

Reference: 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.

(Section 2, page 5)

Request:

- (a) Please fully explain how the industrial load was treated previously for the purposes of losses calculations, how it is now treated, and how this change in treatment impacts forecast transmission losses.
- (b) Please provide an estimate of the difference of increase in losses calculation for industrial load and for total losses for 2007 arising from the AESO's correction of the referenced overstatement.

Response:

- (a) Please refer to TCE.AESO - 01 (b).
- (b) The AESO anticipates the change in 2007 system losses to be significantly less than 1%. The anticipated change is due to the following:
 - a change in the treatment of load in the losses calculation; please refer to TCE.AESO-01 (b) for more information
 - the reduction of the loss forecast (2006 forecast of 3.18 TW.hr vs. the 2007 forecast of 2.897 TW.hr) is due primarily to further improvements in the forecasting process
 - the AESO also had more 2006 actual data available when developing the 2007 losses forecast resulting in an improvement to the forecast.

Reference: Although there is a decrease in losses volumes from 3,180 GWh in 2006 to 2,897 GWh (\$7.0 million), there is a net increase of \$65.0 million in losses costs from the 2006 Update to the 2007 forecast. (Section 2, page 6)

The 2007 losses volumes forecast, utilized 2005 and 2006 actual settlement volumes, and resulted in an anticipated reduction in losses volumes for 2007. Other considerations that have reduced 2007 total losses volumes forecast relative to 2006 include the following:

- 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 forecast.

(Section 2, page 20)

2007 Forecast volumes of 2,897 GWh are 283 GWh lower than the 2006 Forecast of 3,180 GWh, due to industrial load forecast adjustments which had been previously overstated, and includes consideration of historical losses volumes.

(Section 2, page 21)

Request:

- (a) Please provide a full explanation as to the reason total system losses are not increasing as quickly as forecast.
- (b) Of the factors discussed in response to part (a), do any of these factors impact other revenue requirement items (e.g. location of TMR generation may impact losses and TMR costs)? Please fully explain your answer.

Response:

- (a) When developing the 2006 GTA loss forecast, it was noted that losses appeared to be increasing at a faster rate than system load. The AESO attributed the increase in losses to the non-linear relationship between losses and system loading. However, actual data (2006) indicates that losses have not grown as quickly as expected. Actual data recorded in 2006 has been used to estimate a lower loss volume in 2007.
- (b) No. The over forecast of losses does not materially impact other revenue requirement items.

Reference: Section 3 – Tariff Consultation

Request:

- (a) Please advise when the AESO began considering use of the “average and excess” methodology for the classification of bulk transmission costs and when the decision was made to utilize the concept.
- (b) Please confirm that the concept of utilizing the “average and excess” methodology for classification of bulk transmission costs was not included in any AESO materials circulated as part of the AESO’s tariff consultation and thus was not included in any materials which stakeholders could provide comments or feedback on. If this cannot be confirmed, please fully explain.
- (c) Please advise when the AESO began considering the use of cost data from the 2006 Transmission Cost Causation Update (“TCCU”) for PODs less than 7.5 MW and when the decision was made to utilize the concept.
- (d) Please confirm that the use of cost data from the TCCU for PODs less than 7.5 MW was not included in any materials circulated as part of the AESO’s tariff consultation and thus was not included in any materials concerning which stakeholders could provide comments or feedback on. If this cannot be confirmed, please fully explain.
- (e) Please advise when the AESO concluded that a 5% load factor standby load should pay approximately 40% of the tariff for an average load.
- (f) Please confirm that the AESO’s conclusion that a 5% load factor standby load should pay approximately 40% of the tariff for an average load was not included in any materials circulated as part of the AESO’s tariff consultation and thus was not included in any materials concerning which stakeholders could provide comments or feedback on. If this cannot be confirmed, please fully explain.

Response:

- (a) The AESO recalls that an “average and excess” methodology was first raised by stakeholders at a technical meeting held by the AESO on June 14, 2006. Although the AESO conducted a preliminary investigation of the methodology when reviewing stakeholder comments after that meeting, a more thorough assessment was completed in September 2006.

After consideration of stakeholder input at the final tariff consultation meeting on September 21, 2006, the AESO further examined various approaches to cost allocation including consideration of bill impacts and consistency with findings related to backup service costs and rates. The decision to base its proposed 2007 rate design on the “average and excess” approach was made by the AESO in late October 2006.

- (b) The AESO did not present any rate design proposals based on an average and excess methodology as part of its 2007 tariff consultation. As noted in (a) above, the AESO recalls that an “average and excess” methodology was raised by stakeholders at a technical meeting in June 2006. Although the AESO did not specifically present any proposals based on an average and excess methodology, stakeholders were invited to comment on the AESO proposed approaches and were always able to provide comments and feedback on alternative approaches. Some stakeholders did refer to the average and excess methodology in written comments and in individual discussions after the June technical meeting.
- (c) The AESO investigated using cost data from the cost causation study for PODs less than 7.5 MW after consideration of stakeholder input at the final tariff consultation meeting on September 21, 2006. Various approaches to incorporate cost causation study data were assessed in detail during October, including consideration of bill impacts and consistency with other tariff components such as customer contribution policy. The approach that was included in the AESO’s 2007 tariff proposal was finalized on October 25, 2006.
- (d) The AESO did not present any rate design proposals which used cost data from the cost causation study for PODs less than 7.5 MW as part of its 2007 tariff consultation. Although the AESO did not specifically present any proposals which used cost data from the cost causation study, stakeholders were invited to comment on the AESO proposed approaches and were always able to provide comments and feedback on alternative approaches. At least one stakeholder did suggest using cost data from the cost causation study in written comments and in individual discussions during the tariff consultation process.
- (e) The AESO developed its analysis of costs attributable to backup or standby service after consideration of input at a backup rate discussion with stakeholders on September 27, 2006. Following the stakeholder discussion, the AESO investigated backup service considerations during early October, including consistency with other tariff components such as the DTS and DOS rates and consideration of bill impacts. The costs attributable to backup or standby service were finalized on October 23, 2006.
- (f) The AESO did not present an analysis of costs attributable to backup or standby service as part of its formal 2007 tariff consultation. Although the AESO did not formally present any proposals which analyzed costs attributable to backup or standby service, stakeholders were invited to comment on the AESO proposed approaches and were always able to provide comments and feedback on alternative approaches. The AESO did distribute a draft of its analysis of costs attributable to backup or standby service to one stakeholder in late October 2006, and received verbal comments from that stakeholder before filing its 2007 tariff application. As well, some stakeholders suggested the cost basis for a backup or standby service should be further investigated, in written comments received after the final tariff consultation meeting on September 21, 2006.

Reference: Section 3 – Tariff Consultation

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.

(Section 3, page 1, underlining added)

Request:

Please describe what is meant by a “reasonable tariff solution” and which party or parties in the AESO’s view is/are to make the assessment of reasonableness.

Response:

In the context of consultation, the AESO believes the question of “what constitutes a reasonable tariff” is one that all stakeholders had the opportunity to comment on, and continue to have the opportunity to comment on in this EUB review process. The AESO has the obligation to file a tariff proposal with the EUB, and therefore has the responsibility put forward a proposal that it believes is reasonable. Input from stakeholders gathered during the consultation process was considered in the AESO’s proposals as described throughout the Application. Given parties did not agree on all aspects of the proposals (i.e. a negotiated settlement was not reached), the EUB will ultimately decide what is reasonable.

Reference: Section 3 – Tariff Consultation

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.

Section 4 – Rate Design

The proposed changes primarily respond to EUB directions in the three referenced decisions and to conclusions reached in stakeholder consultation during development of the 2007 tariff, with rate levels adjusted to recover the 2007 revenue requirement detailed in section 2 of this Application.

(Section 4, page 1)

Request:

- (a) Please fully explain what is meant by the phrase “consensus among interested parties”.
- (b) Please fully explain what is meant by the phrase “conclusions reached in stakeholder consultation”.
- (c) Please identify specific changes or proposals in the application that reflect “conclusions reached in stakeholder consultation”.
- (d) Please identify what “conclusions reached in stakeholder consultation” have not been reflected in the application.
- (e) Please advise whether the “conclusions reached in stakeholder consultation” were reached as a result of “consensus among interested parties” and if not, on what basis the conclusions were reached.

Response:

- (a) Consensus means agreement. Interested parties in this context are those stakeholders who participated in the AESO’s consultation process as described in Section 3 of the Application.
- (b) The “conclusions” referred to are those the AESO reached on various tariff matters after considering and responding to comments made by stakeholders. The conclusions were arrived at in the context of not only stakeholder input, but the overall considerations of tariff design, as detailed in the Application (e.g. rate design criteria, EUB directives, past tariffs, new data and analyses available since the last GTA, etc).

- (c) The way in which the AESO relied on and responded to stakeholder comments, and the resultant conclusions that form the basis for the AESO's proposals are described throughout the Application.
- (d) The AESO considers the proposals in respect of the 2007 tariff are complete. At the same time, as noted in the Application, the AESO understands stakeholders may have reached different conclusions (i.e. disagree with the AESO's proposals).
- (e) The conclusions were not reached as a result of consensus. Please see the response to (b) above.

Reference: Section 4 – Rate Design

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

- (i) Recovery of the total revenue requirement;
- (ii) Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
- (iii) Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- (iv) Stability and predictability of rates and revenue; and
- (v) Practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable. (Section 4, page 4)

Request:

- (a) In respect of addition of new wires, what price signal does the AESO believe would most appropriately reflect all costs and benefits?
- (b) Does the AESO feel that certain customer behaviours or characteristics reflect the most efficient use of the system and therefore should be “promoted” through its tariff design? Please fully explain your answer.

Response:

- (a) Additions to the bulk and local transmission system are generally required to avoid violation of limits with respect to one or more of thermal capacity, voltage, or stability, as discussed in section 2 of the *2006 Transmission Cost Causation Update* (provided as Appendix C to the AESO’s 2007 GTA). A price signal which reflects the costs and benefits of such additions would be one which encourages a customer to take transmission service in a manner that does not increase the likelihood that those limits would be violated. In general, the AESO considers that an appropriate price signal would encourage consistent and predictable use of system facilities.

Additions to point of delivery facilities are generally required to meet capacity and service location requirements of the customer. A price signal which reflects the costs and benefits of such additions would be one which ensures each customer pays a comparable cost for comparable service, as well as any costs related to facilities not generally provided to other customers. In general, the AESO considers that an appropriate price signal would encourage long-term and predictable use of point of delivery facilities

- (b) In general, the AESO considers that consistent, long-term, and predictable usage patterns contribute to enabling the efficient development of the bulk and local systems. These characteristics therefore reflect the most efficient use of the bulk and local

system. Rather than “promote” such use, however, the AESO considers the purpose of a tariff design is to ensure a customer pays a fair, objective, and equitable amount for the service provided, no matter how the customer uses the service.

The AESO recognizes that, by extension, efficient use of the bulk system should lead to lower charges for a customer, which would “promote” efficient use. But the promotion of efficient use is not a goal of tariff design; fairness, objectivity, and equity is.

Reference: In Decision 2005-096, the EUB considered that the second and third principles would be satisfied by rates which recover costs in the manner in which they are caused. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective, and equitable, and should minimize or eliminate inter-customer subsidies. Cost causation therefore becomes the primary consideration when evaluating a rate design proposal.

(Section 4, page 4)

Request:

- (a) Please describe the nature of the evidence of causation relied on by the AESO to formulate its proposed basis for billing bulk transmission costs. Please advise whether such evidence is based on the causation of existing facilities at the time of their approval, the current use of existing facilities, or the evaluation of factors and behaviours that will cause the need for future facilities?
- (b) Please enumerate the components of AESO costs and indicate if the proposed tariff reflects the cost causation to the greatest extent possible, and those components where factors other than cost causation have resulted in tariff components that do not reflect cost causation to the greatest extent possible.

Response:

- (a) The cost causation evidence relied on by the AESO comprised:
 - the *Alberta Transmission System Wires Only Cost Causation Study* prepared for the AESO by PS Technologies and filed as Appendix B to the AESO's 2006 GTA on January 31, 2005;
 - the *2006 Transmission Cost Causation Update* also prepared for the AESO by PS Technologies and filed as Appendix C to the AESO's 2007 GTA on November 3, 2006, and
 - additional analysis of bulk system data by the AESO and filed as Appendix D to the AESO's 2007 GTA on December 13, 2006.

The nature of the evidence in the 2005 *Transmission Cost Causation Study* included wires costs from the four major transmission facility owners in Alberta; a review of transmission planning practices; zero intercept, minimum system, and other quantitative analysis, and a review of literature and cost of service in other jurisdictions.

As summarized on page 8 of section 4 of the AESO's 2007 GTA, the nature of the evidence in the *2006 Transmission Cost Causation Update* included interviews with "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)." The quantitative analysis was based on hourly metered data for all 240 kV transmission lines in Alberta for 2005 and 2004.

The nature of the evidence in the additional analysis of bulk system data included graphing the hourly metered data for all 240 kV transmission lines in Alberta on peak Alberta Internal Load days in 2005 and 2004, averaged by hour and by month in 2005 and 2004, and as load duration curves for 2005 and 2004.

The evidence is based primarily on cost causation resulting from current use of existing facilities and the evaluation of factors that will cause the need for future facilities. The AESO does not consider that the drivers of transmission system additions will be materially different in the foreseeable future from those which currently exist.

- (b) The components of AESO costs are enumerated in section 2 of the AESO's 2007 GTA, and the cost causation aspects of those costs are thoroughly discussed in section 4 of the GTA. The AESO considers its proposed tariff reflects cost causation to the greatest extent possible in all material respects, and in a level of detail appropriate for transmission costs.

Reference: The AESO has accordingly based the rate proposals in this 2007 tariff application on cost causation principles as much as possible, as described in more detail in the following section. In particular, the AESO has relied on a 2006 Transmission Cost Causation Update (provided as Appendix C) as the basis for functionalization and classification of costs for the proposed rates

(Section 4, page 5, underlining added)

Request:

- (a) Please confirm that the “average and excess” methodology is not discussed in the TCCU.
- (b) Please explain how the AESO can claim it relied on the TCCU for classification of costs when the classification of bulk transmission costs in the proposed AESO rates are based on an “average and excess” methodology – a methodology that is not discussed in the TCCU?

Response:

- (a) Confirmed. The *2006 Transmission Cost Causation Update* studied the functionalization and classification of transmission costs, while the average and excess demand approach was used in the rate design which was not part of the scope of the *Update*.
- (b) As noted in part (a) above, the AESO utilized the average and excess demand approach for the DTS rate design included in its 2007 GTA, which was not part of the scope of the *Transmission Cost Causation Update*. As explained in *Principles of Public Utility Rates* by James C. Bonbright et al. (Public Utilities Reports, Inc., Arlington, Virginia, 2nd Edition, 1988, p 497), the average and excess demand approach “apportion[s] a part of the capacity costs among kilowatt-hours of energy rather than entirely among kilowatt or kilovolt amperes....”

Please refer to the responses to Information Requests BR.AESO-002 (b) and EnCana.AESO-012 (b) for additional discussion.

Reference: 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.

(Section 4, Page 8)

Request:

- (a) Please provide the hourly data referred to (2006-07-20_AESO_2006_Cost_Causation_Update_-_2005_Meter_Data.xls) as part of the record of this proceeding.
- (b) Please explain why the above passage refers to 79 lines when the Excel spreadsheet provided (2006-07-20_AESO_2006_Cost_Causation_Update_-_2005_Meter_Data.xls) includes data for only 75 lines.
- (c) Please provide all data for all excluded lines.
- (d) For each of the 79 lines, please provide the line number, describe the termination points, describe the location of the metering point and indicate the direction of flow for positive and negative metered values.
- (e) Please correlate each of the 79 lines with the transmission paths identified in the draft 10-year plan (10-year Transmission System Plan 2007-2016, dated October 30, 2006, Figures 3 and 4 and Section 4).
- (f) Where a number of 240 kV lines are included in a transmission path, please indicate by transmission path if the path flows of the 240 kV lines can be added directly or if the sign convention adopted requires that some values be inverted (i.e. multiplied by -1) to derive the path flows.

- (g) For each transmission path indicated in the ten-year plan, please indicate the lines for which flow data is not provided. Please also describe the basis for excluding these lines (i.e. not 240 kV, not significant proportion of the path flow, etc.).
- (h) Please explain why the AESO did not combine the lines into transmission paths prior to conducting the analysis described in the reference to this question. Please discuss whether the conclusions of the analysis may be different if the analysis focused on path flows rather than individual lines. Please provide a full explanation.
- (i) Please provide a spreadsheet that includes the hourly data for each path identified in the 10-year plan.
- (j) Please provide graphs as in Appendix D representing the flows on the paths identified in the 10-year plan rather than the 79 lines presented by the AESO in the application.
- (k) Please confirm that in calculating correlation coefficients between line loadings and AIL load, all hours are considered, not merely those hours that are likely to relate to cost causation. If this cannot be confirmed, please explain.

Response:

- (a) The hourly metered 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-c) As noted in the Excel workbooks referred to in part (a) above, data for five of the seventy-nine 240 kV lines examined for the *2006 Transmission Cost Causation Update* was excluded from the workbooks, where those lines connected a single customer or otherwise could be considered to provide confidential information about the operation of a single customer. The Excel workbooks therefore contain data for seventy-four 240 kV lines.

One of the 75 metering points included in the original 2005 data file posted by the AESO on July 20, 2006, did not relate to a 240 kV line, and has therefore been removed from the final Excel workbooks referred to in part (a) above.
- (d) The line number identifiers are included in the Excel workbooks referred to in part (a) above. Additional meter data is not public information.
- (e) The *2006 Transmission Cost Causation Update* did not rely on, nor refer to, the 10-Year Transmission System Plan. While some information regarding the correlation of lines into paths is available in Table 1 on pages 11-12 of the *Update*, the AESO has not correlated all lines and paths and does not believe such information to be relevant to the Application.

- (f) Where there are parallel lines, the loads on the lines can be added to determine the total flow.
- (g) Please refer to part (e) above.
- (h) The purpose of the *2006 Transmission Cost Causation Update* was to review cost causation, and usage of the system. While transmission planners may view path flows to understand trends of energy moving from one area to another, the transmission system is ultimately planned and built one line at a time. Also, meter data is available on a line by line basis. Therefore, the *Update* considered usage on the system line by line, rather than various combinations of lines.
- (i) Please refer to part (e) above.
- (j) Please refer to part (e) above.
- (k) Confirmed.

Reference: Figure 4.3.5 provides average daily and monthly profiles of loading on each of the seventy-nine 240 kV bulk transmission lines in the AES, as well as the daily and monthly profile of ALL (the heavy black line) and the average of all 240 kV lines (the heavy gray line). To plot the profile for each bulk transmission line, the average loading on the line was first calculated over all hours in the year, and then the loading in each hour on each line was expressed as a percentage of the average loading for that line. The profile for each line on an hourly and monthly basis was then plotted, and represents variation from the average for the line expressed as a percentage. These profiles reveal a variety of information.

(Section 4, page 9)

Request:

- (a) Please confirm that Figure 4.3.5 represents “averages of averages” in that the load pattern is averaged over all days and over all months. If the AESO cannot confirm as requested, please fully explain your answer.
- (b) Does the AESO agree that the need for transmission facilities is often driven by conditions at the extreme (i.e. at times of maximum or minimum load or under contingencies at times of maximum or minimum load) rather than average conditions? If the AESO does not agree, please fully explain your answer.
- (c) Is it the AESO’s position that the degree of path loading in hours other than the top flow hours is relevant in terms of cost causation? If so, please fully explain. If not, please explain the relevance of the flow duration data (Appendix D) presented by the AESO in this application.

Response:

- (a) Confirmed. The AESO reviewed data both on an hour-by-hour basis and on various average bases in an attempt to discover patterns or trends in line loading. The AESO considered the charts provided in Figure 4.3.5 to be illustrative of the lack of consistent patterns and trends in the line loading data.
- (b) The AESO agrees that the need for transmission facilities is often driven by conditions at the extreme on the specific facilities being reinforced or expanded, rather than on the overall system. The discussion in section 4.3.2 of the AESO’s Application relates to whether those extreme conditions on the specific facilities being studied occur at the same time as the overall system extreme conditions. If there was strong correlation, the individual transmission lines would be expected to experience extremes at similar times or in similar patterns, and averages should reveal similar loading patterns over a majority of transmission lines. Such patterns were not seen, as illustrated in Figure 4.3.5.

- (c) The degree of path loading in hours other than the top flow hours is relevant in terms of cost allocation, as discussed in the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-026.

However, the load duration curves on the final page of the Additional Analysis of Bulk System Data (provided as Appendix D of the AESO's 2007 GTA) were provided as an additional illustration of the differences between transmission line loading (individually and on average) and AIL system loading.

Reference: The AESO also reviewed the profiles and Appendix D analysis with AESO system planners. All agreed with the conclusions that some bulk transmission line loading varies with total system load, while others do not. Although bulk transmission lines are designed and built to accommodate maximum loading on the line, that maximum loading does not always coincide with maximum system load. (Section 4, page 9)

Request:

Please explain whether the conclusion “maximum system loading does not always coincide with maximum system load” is based on existing system loading, forecast future loading or some other basis.

Response:

The conclusion was based on both existing system loading and forecast future loading. This characteristic of the transmission system is not expected to change in the foreseeable future.

Reference: 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 patterns.

(Section 4, page 9, underlining added)

Request:

- (a) Can the AESO confirm that the need for facilities (and therefore cost causation) is frequently attributable, in whole or in part, to contingency conditions? If not, please fully explain.
- (b) Please fully explain the relationship, if any, between current usage of the system and cost causation.
- (c) Is the AESO assuming that existing flows on the bulk transmission system are representative of future flows? If so, please fully explain how the AESO can justify this view absent the assumption that load and generation at each POD and POS increases proportionately in the future.
- (d) If cost causation is the primary goal in rate design, how does this reconcile with the (implied) suggestion in the quoted passage that current usage (rather than cost causation) is relevant in cost classification?
- (e) If cost causation is not the basis for determining cost classification please fully explain the basis.

Response:

- (a) Yes, the need for facilities is often based on planning criteria with consideration of contingencies.
- (b) Costs are generally caused by expansion of the transmission system. Expansion of the transmission system occurs on the basis of the current usage of the system plus the forecast addition of generation and load. Since the forecast of future generation and load will never be perfectly accurate, current usage of the system is commonly used as a proxy for cost causation in cost of service studies. For example, load profiles frequently used in cost studies are based on actual meter data or on load research which is based on a sample of actual data.

- (c) No. The *2006 Transmission Cost Causation Update* is not used for planning of the transmission system. Please refer to part (b) above.
- (d-e) Please refer to part (b) above.

Reference: 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.

(Section 4, pages 11-12)

Request:

- (a) Please provide a copy of the NERA study for the record of this proceeding.
- (b) Please confirm that the classification NERA found to be reasonable was the classification discussed in the TCCU (Appendix C to the application); namely, the classification that was based on the minimum system approach, and not the "average and excess" methodology recommended by the AESO in this application. If this cannot be confirmed, please fully explain the classification that NERA found reasonable.
- (c) Does the AESO agree with NERA's comments that the use of a factor to reduce the demand classification in proportion to the average loading at the time of AIL peak is not appropriate? If the AESO does not agree with NERA's comments, please fully explain why.

Response:

- (a) Please refer to the response to Information Request BR.AESO-001.
- (b) Confirmed. NERA was asked to review the *Wires Only-Cost Causation Study* dated January 25, 2005 and the *2006 Transmission Cost Causation Update* dated September 15, 2006, both of which dealt with functionalization and classification of transmission costs but not rate design.

The average and excess method was subsequently applied by the AESO in the development of the DTS rate design. The AESO notes that NERA commented in its conclusions (p. 17), "AESO could use a version of the 'Average and Excess' (A&E) allocation method, which uses the system load factor to define the percentage of costs to be allocated on the basis of energy, and one minus the system load factor to define the portion to be allocated using NCP."

- (c) The AESO is not convinced it is inappropriate to use the factor applied in the 2006 rate design and initially proposed for the 2007 rate design, especially if costs are to be billed on the basis of coincidence with system peak. The AESO considers that recovering bulk system costs on a coincident peak basis is not justified from a cost causation perspective, and therefore some adjustment is required to reflect that most bulk costs are not related to coincident peak. The proposed factor could be utilized — and perhaps refined — in the absence of a superior alternative approach.

In preparing the 2007 Application the AESO concluded that the average and excess method was such a superior alternative, in that it better addressed the underlying rationale for the factor discussed above as well as other aspects important to the rate design (such as equitably charging customers having different load factors).

Reference: 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.

(Section 4, page 12)

Request:

In stating that there is “no basis to support cost recovery based on loading at different times of day and different months of the year” please confirm that the AESO also concludes cost causation is not based on peak demand at different times of day and/or different months of the year. If this cannot be confirmed, please fully explain.

Response:

Cost causation for individual transmission system components is based in large part on peak loading at a specific time of day and specific month of the year. However, as discussed in the response to Information Request IPCAA.AESO-010 (b), the peak loading on individual components frequently does not coincide with overall system peaks, and occurs on different transmission system components at different times and in different months. The discussion in section 4.3.2 of the AESO’s 2007 GTA 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.

Since cost recovery applies to all transmission system components collectively rather than to individual components separately, it would be inappropriate to base cost recovery on loading at different times of day or different months of the year.

Reference: The AESO also does not consider it appropriate to recover bulk system costs wholly on an energy basis. An energy (\$/MWh) charge indicates that total throughput on the bulk system is the most important cost consideration. This is clearly not the cost driver for the bulk system; individual bulk lines and other equipment are designed to meet maximum demand requirement, not total throughput.

(Section 4, page 12)

Request:

As the AESO concludes that maximum demand rather than average demand over all hours (energy) is the most important cost consideration, please confirm that this is consistent with a view that high load factor industrial loads impose lower bulk transmission unit costs than lower load factor residential and commercial loads. If this cannot be confirmed, please fully explain.

Response:

If maximum demand was the sole cost consideration and if both the high load factor industrial load and low load factor residential and commercial loads imposed peak load on the transmission system coincident with the time of maximum demand, then:

- costs should be recovered solely on a demand basis,
- both loads would experience **the same** unit costs on a demand (\$/MW) basis, and
- the high load factor industrial load would experience **lower** unit costs on a usage (\$/MWh) basis.

As discussed in the response to Information Request IPCAA.AESO-022, transmission system components experience maximum stress due to complex interrelationships between many elements such 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. The peak load of a low load factor load will likely coincide with maximum load on some transmission system components. The repeated or extended peak loads of a high load factor load will likely coincide with maximum loads on more transmission system components. This varying probability of coincidence with maximum stress on transmission system components is addressed through the average and excess demand approach, such that in the proposed DTS system charge:

- costs are recovered in part on a demand basis and in part on a usage basis,
- the high load factor industrial load would experience **higher** unit costs on a demand (\$/MW) basis, and
- the high load factor industrial load would experience **lower** unit costs on a usage (\$/MWh) basis.

Reference: 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.

(Section 4, pages 12-13)

Request:

- (a) Is it the AESO's position that demand in any hour could equally cause bulk system costs?
- (b) Please identify those hours that, directionally, are more relevant and those that are least relevant to bulk system costs.

Response:

- (a) As discussed in the response to Information Request IPCAA.AESO-022, 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. Demand in any hour could therefore potentially cause bulk system costs, but those bulk system costs would not necessarily be equal.
- (b) Some transmission system components are likely to be at or near maximum loading conditions in every hour of the day. However, in the average hourly loading graphs provided on pages 15 and 16 of the additional analysis of bulk system data (provided as Appendix C to the Application on December 13, 2006), there appears to be two hours when many lines experience less than maximum loading conditions: around 8:00 am and around 11:00 pm. Those two hours may be less relevant to bulk system costs than other hours.

Reference: 4.3.5 Proposed Transmission Cost Functionalization and Classification

The final functionalized and classified wires costs incorporating the findings discussed above are provided in Table 4.3.7.

Table 4.3.7 Functionalized and Classified Transmission Wires Costs ("2007"), % of Total

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	41.7%	34.0%	7.7%	-
Local System	17.4%	14.3%	3.0%	-
POD	40.9%	35.9%	-	5.0%
Total	100.0%	84.2%	10.8%	5.0%

Note: Totals may not add due to rounding

The AESO notes that these findings are further modified for rate design purposes as discussed in section 4.5 of this application.

(Section 4, page 15)

Request:

Please confirm that Table 4.3.7 represents the AESO's view as to the classification of costs, excluding the further rate design considerations referenced in the last sentence of the quoted passage. If this cannot be confirmed please fully explain your answer.

Response:

Confirmed.

Reference: 4.4 Ancillary Services Cost Classification

The classification of ancillary services costs was reviewed extensively in the AESO's 2006 GTA. No changes are proposed to the cost classification in the 2007 application from that approved for the AESO's 2006 tariff.

(Section 4 – Page 15)

Request:

- (a) Please confirm that TMR costs are recovered on an energy basis. If this cannot be confirmed, please fully explain the basis for the recovery.
- (b) Please confirm that as new wires are built, particularly in the Northwest, the level of TMR costs will be reduced.
- (c) Please confirm that as new wires replace TMR, cost recovery will shift from energy towards demand and energy.
- (d) Please advise whether the AESO agrees that as TMR costs are a replacement for wires investment, TMR costs should be recovered in the same manner as wires costs. If the AESO does not agree, please fully explain your answer.

Response:

- (a) Confirmed.
- (b) The construction and commissioning of new wires in the Northwest is expected to reduce the need for transmission must-run (TMR) service in the area. TMR costs are a function of contract details and typically are affected by pool price.
- (c) Based on the proposed tariff, this would be the expected effect.
- (d) Although TMR service may provide a less expensive or short-term alternative to a wires solution in providing reliable transmission service, TMR costs are fundamentally different from wires costs. TMR costs reflect relatively short-term contractual arrangements with suppliers, and vary over time based on volume, pool price, and contractual provisions. Wires costs represent long-term fixed investments which vary little after construction.

In accordance with these differences, TMR costs are appropriately recovered through a usage (\$/MWh) charge while wires costs are appropriately recovered through a combination of demand (\$/MW) and usage (\$/MWh) charges.

The recovery of TMR costs through a usage (\$/MWh or percentage of pool price) charge is also consistent with current and prior transmission tariffs.

Reference: 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

(Section 4, page 16 Underlining added)

Request:

Please confirm that the recovery in the proposed DTS tariff is neither 81.5%/18.5% demand/energy nor 82.5%/17.5% demand/energy.

Response:

Confirmed. The referenced demand- and energy-related proportions are calculated from Table 4.3.7 on page 14 of section 4 of the Application, before additional modifications for rate design purposes. Those modifications, as detailed in section 4.5 of the Application, result in an allocation on a 51.4% demand- and 48.6% energy-related basis, as provided in Schedule 5.3 in section 5 of the Application (or as can be calculated from Table 4.5.1 on page 17 of section 4 of the Application).

Reference: Section 7 – Tariff Proposal

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.

(Section 4, page 16)

Request:

- (a) Please confirm that NERA's review of the TCCU questioned the validity of the basis for applying the factor to moderate the demand classification.
- (b) Does the AESO support NERA's assessment that questions the basis for the factor to moderate the demand classification?
- (c) Please fully explain the AESO's basis for supporting or rejecting NERA's assessment.

Response:

- (a) Confirmed.
- (b-c) Please refer to the response to Information Request IPCAA.AESO-013 (c).

Reference: Stakeholders also suggested the AESO examine other approaches to cost classification, including the “average and excess method”.

(Section 4, page 16)

Request:

- (a) Please identify the stakeholder submissions suggesting the average and excess method.
- (b) Please provide a discussion setting out the AESO’s complete justification for utilizing the average and excess methodology for classifying transmission costs as demand or energy related.
- (c) Does the AESO agree that the conceptual basis for allocating generation costs as per the average and excess methodology is stronger than the basis for allocating transmission costs? If the AESO does not agree, please fully explain.

Response:

- (a) The AESO recalls that an “average and excess” methodology was first raised by stakeholders at a technical meeting held by the AESO on June 14, 2006. Stakeholders who registered for that meeting were ADC, ATCO Electric, City of Medicine Hat, EnCana, EPCOR, IPCAA, PPGA (Kinder Morgan), and TransCanada Energy. EPCOR suggested an average and excess methodology in written comments submitted on July 11, 2006, and FIRM suggested an average demand approach to allocate costs based on energy in written comments submitted on August 29, 2006. EnCana recommended the AESO adopt an energy allocator to recognize different POD load factors, in written comments submitted on October 10, 2006. The AESO also recalls the average and excess demand approach being raised during discussions with PICA and TransCanada Energy during the 2007 rates consultation process.

Please refer to the response to Information Request IPCAA.AESO-003 (a-b) for additional information.

- (b) Please refer to the response to Information Request EnCana.AESO-012 (b).
- (c) No, the AESO does not agree. Although the average and excess demand method is frequently used to allocate generation costs, its justification is that it addresses the probability of a load’s coincidence with peak loading on the system when that coincidence cannot be measured or predicted directly. The AESO considers such justification applies equally to the transmission system, when the various components of the transmission system experience peak loading at different times.

Reference: 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.

(Section 4, page 16)

Request:

Is it the AESO's position that the probability that individual POD loads will coincide with maximum stress on transmission system components varies because the maximum stress on transmission system components occurs on a random basis or that the peak loads occur on a random basis? Please fully explain your answer.

Response:

The AESO suggests that neither the maximum stress on transmission system components nor the peak loads at individual PODs are "random" events. Transmission system components experience maximum stress due to the interaction primarily of different customers' loads and different generators' outputs with the physical characteristics of the interconnected system's components on a real-time basis, combined with specific elements being in and out of service for various reasons at various times. The peak loads at individual PODs are generally due to customers' choices related to equipment and (where onsite generation exists at a POD), generation operation. Maximum stress and peak load are therefore not random in the sense of "occurring in a manner without reason, purpose, or pattern," but are caused by complex inter-relationships between many elements.

If the word "variable" is substituted for "random" in the question, then, in the context of the quoted reference, the AESO suggests the more important factor is the variability of an individual POD's peak load, especially for a low load factor customer.

The discussion in section 4.3.2 of the 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. Thus, no matter when a POD's peak load occurs, it is likely it will coincide with maximum load on some transmission system components. If a POD exhibits repeated or extended peak loads, it would likely coincide with maximum load on more transmission system components. If a POD exhibits a continuous peak (that is, a flat load profile), it would coincide with maximum load on all transmission system components. The average and excess demand approach addresses this varying probability of coincidence between an individual POD's peak load and maximum stress on transmission system components.

Reference: 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.

(Section 4, page 16)

Request:

Please indicate what the AESO would consider “similar”.

Response:

The AESO notes that the sentence which follows the quoted reference provides the number of DTS customers in different load factor ranges:

- 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 AESO suggests that considerations of similarity would vary from case to case, but a group where 47% of customers have high load factors, 29% have medium load factors, and 24% have low load factors would not be considered “similar” under any circumstances.

Reference: 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.

(Section 4, pages 16-17)

Request:

- (a) Please explain what the AESO means by “recognition of variation in load factor”.
- (b) Please confirm that the proportion of “average” versus “excess” is a linear function of load factor. If this cannot be confirmed, please fully explain.

Response:

- (a) Please refer to the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-022.

As provided in an excerpt from *Principles of Public Utility Rates* by Bonbright et al. in EnCana.AESO-012 (b), the average and excess demand method assumes “a greater *probability* of coincidence if the ratepayer is operating on a high load factor than if he or she is operating on a low load factor.” (p 498) This is what the AESO means by “recognition of variations in load factor.”

- (b) Confirmed. Although the average versus excess portions do vary linearly with load factor, the load factor used in the average and excess demand method in the proposed 2007 rate design is not that of an individual customer. The load factor is the length-weighted average 240 kV line load factor for 2005 and 2004, and reflects loading on transmission system components which results from complex interrelationships between many elements as explained in response to Information Request IPCAA.AESO-022.

Reference: 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.

(Section 4, page 17)

Request:

Please confirm that in the present application the relative relationship between “average” and “excess” is determined by the loading in hours that are not related to maximum loading on the transmission system. If this cannot be confirmed, please explain.

Response:

Not confirmed. As discussed in section 4.3.2 of the AESO’s 2007 GTA, there is no single period which defines “maximum loading on the transmission system.” 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.

Please refer to the response to Information Request IPCAA.AESO-022 for additional information.

Reference: The excess component represents the amount of system load above the average, and is simply the balance of costs which is recovered on a non-coincident peak basis. From the length-weighted average 240 kV line load factor discussed above, 51.4% of transmission system costs would be classified as demand-related and recovered through demand charges. (Section 4, page 17)

Request:

Please fully describe the relevance, if any, of average load in terms of cost causation.

Response:

The *Electric Utility Cost Allocation Manual* by the National Association of Regulatory Utility Commissioners (Washington, D.C., January 1992, p 49) describes the relevance of average load in the average and excess demand methodology as follows:

The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.

The same relevance applies to the transmission system: average 240 kV line load factor represents the transmission line capacity that would be needed if all lines were loaded at a constant level throughout the year.

Reference: The AESO recommends the 48.6% energy-related and 51.4% demand-related classification for recovery of the entirety of transmission system costs. The average and excess method is generally an alternative to the minimum system approach that was utilized in the original Transmission Cost Causation Study, and the two approaches should not be applied together. (Section 4, page 17)

Request:

Please fully explain the basis for the statement that the “average and excess method is generally an alternative to the minimum system approach”.

Response:

The proportions of demand- and energy-related costs are generally determined through application of a single cost allocation methodology (coincident peak, non-coincident peak, average demand, average and excess, minimum system, etc.) to all costs in a function, subfunction, or property account. The most appropriate allocation methodology is chosen for the costs being allocated. In the AESO’s experience, multiple allocation methodologies are generally not applied sequentially to the same costs.

Reference: 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.

(Section 4, page 17 underlining added)

Request:

Please fully describe the signal(s) that customers are intended to respond to and the results of customers both responding to and not responding to the signal.

Response:

As discussed in the response to Information Request IPCAA.AESO-006 (a), the AESO considers that for the bulk and local transmission system an appropriate price signal would result in consistent and predictable use of system facilities.

In the quoted reference the AESO is referring to the price signal provided by a billing capacity charge which includes ratchet and contract minimum provisions. The AESO considers that such a charge provides a clear signal that customers should avoid demand peaks and should strive for as flat a load profile as practical. If customers respond to the price signal, the AESO will be able to plan and operate the transmission system in an orderly and efficient manner, and will be able to better avoid violation of limits with respect to thermal capacity, voltage, and stability. If customers do not respond to the price signal, it will be more difficult for the AESO to develop the transmission system in an orderly and efficient manner, to operate the transmission system effectively, and to avoid violation of the limits just mentioned.

Reference: With respect to differences between substations serving smaller loads and those serving larger ones, the Customer Contribution Study also found that no small load services have been interconnected in recent history. Specifically, load services smaller than 7.5 MW have not been interconnected since 1999 nor are any currently being interconnected. The AESO was therefore unable to quantitatively assess the costs of substations serving small load using the recent project data in the Customer Contribution Study.

(Section 4, page 19, underlining added)

Request:

- (a) Would the AESO agree that a grandfathered rate is a rate that is available to existing customers, is adopted in recognition of historical factors which likely are no longer relevant and is not available to new customers? If the AESO does not agree please discuss the AESO's definition of a grandfathered rate.
- (b) Given that there are no recent or forecast loads less than 7.5 MW, and that costs for PODs were assessed based on historical costs, does the AESO agree that the alterations to the tariff to recognize smaller loads are, in effect, a grandfathered rate? If not, please fully explain.

Response:

- (a) In addition to the characteristics suggested, the AESO understands that a grandfathered rate is also generally not available to existing customers who are not already on the rate being grandfathered.

The AESO also understands that a grandfathered rate may be adopted for a variety of reasons beyond historical factors which likely are no longer relevant, such as avoidance of rate shock to customers on the grandfathered rate, legislative or policy changes preventing a service being offered to new customers, and restructuring of rate classes into more, fewer, or significantly different classes.

- (b) The AESO does not agree. As stakeholders pointed out during consultation, although no small load services have been interconnected since 1999, a small load could appear in the future and would be served on the proposed rate. Also, an existing service larger than 7.5 MW could reduce its capacity to less than 7.5 MW and would be served on the proposed rate.

Since the rate would be available to new services if they appear and would also be available to existing services which are not currently smaller than 7.5 MW, the AESO does not consider the rate changes to recognize smaller loads to be, in effect, a grandfathered rate.

Reference: In reviewing the application of the substation fraction, the AESO notes that the recommended cost function on which the POD charge is proposed to be based was developed using data for single-service load-only interconnections. Where a substation serves both load and generation, or multiple loads, the cost function must be adjusted to reflect the “substation fraction” approach established by the EUB during the course of the AESO’s 2005-2006 GTA. All but two transmission substations with multiple services (either load and generation or multiple loads) have more than 7.5 MW of total contract capacity, and therefore give rise to incremental costs in accordance with the second demand component of the recommended cost function: \$0.154 million/MW × DTS Capacity above 7.5 MW.

In effect, the customer and first demand components of the cost function can be considered representative of the fixed cost of multiple-service substations, since almost all are above 7.5 MW in total capacity. Since the fixed cost should be shared between services at a multiple-service substation, those two cost components should be shared based on the substation fraction of each service. Accordingly, the substation fraction should apply to the customer and first demand rate components to ensure equitable sharing of charges between customers at multiple service substations.

(Section 4, page 22)

Request:

- (a) Where the AESO states “more than 7.5 MW of total contract capacity” please explain whether the total contract capacity means the sum of STS plus DTS demand or the largest of STS or DTS capacity.
- (b) If “total contract capacity” means the sum of STS plus DTS capacity, please explain why this measure is more relevant to achieving economies of scale than the larger of STS or DTS capacity.

Response:

- (a) Total contract capacity refers to the sum of all contract capacities at a substation with multiple services, and includes both load (DTS) and generation (STS) contract capacities.
- (b) The AESO agrees that, at dual-use substations, the larger of the DTS or STS capacity would generally be more indicative of economies of scale than the sum of DTS and STS capacities. However, the AESO’s observation — that most substations with multiple services are not “small” substations — remains valid.

Out of the 80 transmission substations with multiple services, only five have both total DTS contract capacity less than 7.5 MW and total STS contract capacity less than

7.5 MW. Of those five substations, only two have transformers smaller than 10 MVA and may therefore exhibit lower economies of scale compared to larger substations. However, even those two substations are close to the 7.5 MW threshold: the transformers at the two smaller substations are 6 MVA (serving a maximum of 5.3 MW DTS contract capacity) and 7 MVA (serving a maximum of 6.8 MW DTS contract capacity).

The 7.5 MW threshold was developed not as a precise measure of economies of scale but as the boundary of data contained in the analysis. Since it is not a precise measure of economies of scale and since even the two smallest multiple-service substations are near the threshold, the AESO suggests it remains appropriate to apply the substation fraction to the customer and first demand rate components of the DTS rate for simplicity and practicality.

Reference: In reviewing application of the Primary Service Credit, the AESO recommends the EUB's question be broadened in recognition of the small services with unusual characteristics discussed in points (a) and (b) above, to "what additional relief, if any, should be offered for customer interconnections where the TFO does not own conventional transformation facilities?" Such interconnections would include:

- those with customer-owned transformation (as contemplated in the current Primary Service Credit);
- those utilizing metering transformers (as discussed in point (a) above);
- those which are isolated from the transmission system (as discussed in point (b) above); and
- other unusual interconnections such as those taking service at transmission-level voltage without the use of transformation facilities.

The AESO proposes all such services be eligible for the Primary Service Credit.

(Section 4, pages 22-23)

Request:

- (a) Please confirm that isolated generation sites incur energy costs in excess of Pool Price that are pooled into the AESO tariff. If the confirmation requested cannot be given, please fully explain your answer.
- (b) Please provide an estimate of these excess energy costs on a \$/MWh of isolated load.
- (c) Please compare the excess energy costs with unit POD transmission charges (\$/MWh) for DTS load.
- (d) If the excess energy costs exceed the unit DTS POD transmission charges, please fully explain why these sites should receive relief on POD costs through the PSC.

Response:

- (a) Confirmed, as required by section 3 of the *Isolated Generating Units and Customer Choice Regulation*.
- (b) The cost of isolated generation was \$5.9 million in 2005, as reported on line 3 in Schedule 2.0, on pages 8-9 of section 2 of the AESO's 2007 GTA. The energy volumes of isolated communities in that year totaled about 80,000 MWh, for an equivalent \$/MWh cost of \$73.75/MWh.
- (c) On average, an isolated community has metered energy of 736 MWh and billing capacity of 1.5 MW in a month. Under the AESO's proposed tariff, the DTS bill for such a

community, excluding the proposed Primary Service Credit, would be about \$15,500.00 per month, resulting in an equivalent \$/MWh cost of \$21.06/MWh.

- (d) The treatment of costs relating to service to isolated communities is to be determined independently under the *Isolated Generating Units and Customer Choice Regulation*. The *Regulation* describes the treatment of commodity (or energy) costs in subsection 3(a) and the treatment of transmission (or system access service) costs in subsection 3(b). With respect to the treatment of transmission costs, subsection 3(b) states:

the owner of the electric distribution system in whose service area the isolated community is located must pay the Independent System Operator for system access service as if the isolated community were being provided with system access service via the interconnected electric system

Transmission costs for isolated communities are to be paid without regard to the commodity cost treatment associated with those communities. The isolated communities are not interconnected through TFO-owned conventional transformation equipment, and should therefore be charged consistent with other services interconnected through unconventional facilities. Application of the Primary Service Credit appropriately recognizes the reduction in costs attributable to services which do not utilize TFO-owned conventional transformation.

Reference: Based on these considerations, the AESO completed a POD-by-POD comparison of bills under the 2005, 2006, and proposed 2007 DTS rates. Monthly bills were calculated under each rate using actual customer billing determinants from June 2005 through May 2006 (including demand determinants from June 2004 through May 2005 for ratchet calculations). The twelve monthly bills were then averaged for each rate, and increases attributable to the rate changes determined. The average bills for individual PODs are provided in Appendix E, and are grouped by billing capacity and load factor in Table 4.5.2.

(Section 4, page 25)

Request:

- (a) Please provide the spreadsheet model used to calculate the rate impacts in Appendix E. Please provide the model in a form that permits the calculation of bill impacts resulting from changes in demand and energy charges.
- (b) Please provide the model with the complete data set. If the AESO cannot provide the model with the complete data set due to confidentiality concerns, please describe the data that the AESO feels must be considered confidential and explain why the data should be considered confidential. Please provide all other data.
- (c) Please indicate the substation fraction applicable to each POD listed in Appendix E.

Response:

- (a-b) The AESO views the individual customer billing determinants utilized in the bill impact analysis to be confidential information, and does not consider it appropriate to disclose such information publicly. The analysis was based on monthly customer-specific data for metered energy, metered demand, coincident demand, contract capacity, substation fraction, and average commodity price. The AESO considers that providing this quantity of detailed individual data, even when not identified by customer name or account, exceeds the usual standards of disclosure for billing information.

Beyond the individual customer billing determinant data, the bill impact analysis included only the AESO's 2005, 2006, and proposed 2007 rates as inputs. Those rates are publicly available on the AESO website and in EUB decisions.

The AESO notes that Appendix E provides average monthly metered energy, billing capacity, load factor, and substation fraction for each DTS service. These averages can be used to estimate average monthly bills, and therefore bill impacts, under each of the relevant tariffs. The AESO believes that such an analysis would allow an intervenor to assess any rate alternatives which the intervenor wishes to bring forward.

- (c) The substation fraction is already provided for each service in Appendix E, in the column labeled "SF".

Reference: The AESO further understands that under the provisions of the current DTS rate, customers who require backup service generally respond to the DTS rate structure in two ways:

- They contract for the capacity needed during the backup load conditions, and thereby minimize the probability of capacity or other system constraints; or
- They contract for the capacity needed during normal load conditions, incur ratchets based on the capacity needed during the backup load conditions, and incur higher probability that constraints may exist at those times.

(Section 4, page 34)

Request:

- (a) Is it the AESO's position that it plans and causes facilities to be built to meet all contracted capacity?
- (b) If this is not the AESO's position, please fully explain why loads that do not contract incur higher probability that constraints may exist.

Response:

- (a) Yes, the AESO plans facilities to ensure that contracted capacity as well as forecast service requirements can be served, subject to an appropriate level of diversity regarding system facilities.
- (b) When services operate above their contracted capacities, they may impose loads on the transmission system beyond those for which the transmission system in the area was planned. Such loads may therefore cause constraints on the transmission system.



Reference: In either case, customers who require backup service incur charges higher than those which would be incurred if their load never exceeded “normal” levels. The AESO therefore examined such charges in the context of the costs caused by use of the transmission system for backup service. (Section 4, page 34 underlining added)

Request:

Please confirm that the analysis undertaken pertains only to bulk and local transmission, not POD related costs. If this cannot be confirmed, please provide a full explanation.

Response:

Confirmed.

Reference: 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. (Section 4, page 34)

Request:

Please fully describe and quantify, to the extent possible, what the AESO means by “a small number” and “reasonable non-coincidence” in the above statement.

Response:

The AESO’s assessment was qualitative rather than quantitative. In context, a “small number” was two or three such loads in a planning area. “Reasonable non-coincidence” was not defined, but would generally refer to not occurring at the same time, not occurring during a post-contingency time period, and not occurring during or immediately following the return to normal operation after resolution of a contingency.

Reference: Stakeholders who provided comments on the proposed backup service rate generally supported it. At the same time, the AESO continued to review the details of the rate within the AESO and developed significant concerns about the unscheduled nature of the service. Specifically, the AESO was concerned that with only a usage charge:

- (a) customers would have minimal incentive to manage backup service requirements such that usage of the service could increase significantly, and
- (b) significantly increased usage could create unforecast and unscheduled loading on the transmission system with considerable risks of voltage deviations or tripping of system elements which would affect all customers in an area and which might result in cascading effects in other areas.

(Section 4, page 35)

Request:

- (a) Please confirm that it is the AESO's position that the greater the amount of backup load, the higher the potential risks. If this cannot be confirmed, please fully explain.
- (b) Please elaborate on what is meant by "significantly increased usage". At what level of usage would such risks arise?

Response:

- (a) The AESO's concern is not specifically with the quantity (in megawatts of demand) of backup load, but more with the frequency and probability that the transmission system will be required to serve that load without specific forewarning.
- (b) As discussed in section 4.6 of the AESO's 2007 GTA, unscheduled usage of the transmission system is permitted under the AESO's current tariff. The risk of voltage deviation or tripping of system elements from unscheduled usage therefore already exists, and the AESO plans, builds, and operates the transmission system to reasonably manage such risks as they currently exist. There is no specific threshold at which risks for system operations and reliability arise.

The AESO's concern is that if unscheduled usage were to increase, the potential for voltage deviations or tripping of system elements would also increase. The outcome could be a decrease in levels of transmission service quality and reliability, or an increase in costs as the system is reinforced and operations are changed to address the increase in unscheduled usage. The issues therefore include balancing reliability and efficiency with reasonable cost, and attributing those costs to different users of the transmission system, rather than limiting risks to a certain threshold.

Reference: Although (as already noted) the current DTS rate allows unscheduled usage, the ratchet provisions of the rate generally encourage customers to minimize backup service requirements. Drastically reducing the charges attributable to backup service use would be expected to encourage unscheduled loading and result in increased risks for system operations and reliability. The AESO estimated that 1,500 to 2,000 MW of load could potentially request backup service and incur minimal cost for utilizing it. Some of these customers would likely be concentrated in areas where concurrent use would intensify operations and reliability concerns. (Section 4, page 35)

Request:

Please provide and explain any assessment(s) the AESO has undertaken that quantify the expected amount of backup service at different tariff levels.

Response:

The AESO has not undertaken such an assessment. The amount of standby usage that might result at the different tariff levels is not a direct consideration inherent in the proposed rates. Of primary concern in the AESO's rate design, as proposed in the Application, is that the rates for standby (and all other system access services) is based on cost causation. If this is the case, then regardless of the level of usage, the rates would be appropriate and would not encourage usage that increases operational risks to the AESO without appropriate cost consequences to the users.

Reference: Stakeholders suggested the AESO's concerns with increased or concentrated utilization of backup service could be addressed through conditions or eligibility restrictions on the service, either for a temporary period while the impact of the service is assessed or on a permanent basis. The AESO suggests such conditions or restrictions on eligibility could be considered preferential or arbitrary. For example, backup service is characterized by short duration, infrequent, and unscheduled usage, and those characteristics could also be exhibited by a low load factor load service which intermittently runs above contracted capacity (for example, periodic operation of equipment in a large-machinery testing facility). 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. (Section 4, page 35)

Request:

- (a) Please confirm that the statement, "there is no cost or operational basis for distinguishing between backup service to a generator and intermittent operation of a load service" assumes that both the backup and load services are random in nature. If this cannot be confirmed, please fully explain your answer.
- (b) Please confirm that backup and load services may be dissimilar if the load service had a pattern of usage, for example, if the load service only occurred during regular working hours. If this cannot be confirmed, please fully explain your answer.

Response:

- (a) Not confirmed. Neither backup service to a generator nor intermittent operation of a load service would be expected to be random in the sense of "occurring in a manner without reason, purpose, or pattern." The AESO considers both types of service to be unscheduled as well as unpredictable based on information available to the AESO.
- (b) Not confirmed. The AESO expects that, in certain but not necessarily all instances, both backup service to a generator and intermittent operation of a load service may exhibit a pattern of usage. For example, it is possible that backup service could be required more frequently during regular working hours if load and generation are both operating at higher capacity during those hours. Despite any such pattern, if the service is required only intermittently (for example, three or four times a year), it still remains unscheduled and unpredictable.

Reference: The AESO also reviewed a “physical assurance” option recommended in California (*Interim Decision Adopting Standby Rate Design Policies*, California Public Utilities Commission, July 12, 2001, pp. 57-60), where if control devices are installed which disconnect load in the event of a generator outage the customer can receive a lower rate. If such a device is installed by a transmission customer in Alberta, the ratchet provision of the AESO’s current DTS rate would be avoided and the customer would accordingly see no additional charges attributable to backup service. The California PUC concludes, “If a customer is not willing to offer such physical assurance, the utility must construct infrastructure or continue to operate existing facilities to ensure that load from a customer taking on-demand backup service can be served. Therefore, it is appropriate for those costs to be recovered from backup customers.” The AESO generally concurs, but suggests no special option is required if the DTS rate structure appropriately charges for backup service. (Section 4, page 36)

Request:

- (a) Please indicate if the AESO would be willing to consider a physical assurance option if the AEUB were to conclude that the DTS rate structure proposed does not appropriately charge for backup service.
- (b) If the AESO were willing to consider such an option, please describe the tariff adjustments that would follow from such an option.

Response:

- (a-b) If a “physical assurance” control device is installed by a customer, then the customer’s load will be disconnected in the event of a generator outage and the transmission system will experience no increase in load at the customer’s service. With no increase in load, no additional charges will accrue to the service, and there would be no requirement to adjust the standard DTS rate that would apply to such a service.

If the customer chooses not to install a physical assurance device, and the EUB were to conclude that the proposed DTS rate does not appropriately charge for the resulting backup service requirement, then the AESO would expect to develop an alternate cost-based rate to address the issues underlying the EUB’s conclusion. The AESO has not speculated on what the specific issues might be nor what tariff adjustments might be required to address them, given the backup service considerations already reviewed and addressed in the development of the proposed DTS rate design.

Reference: Although the transmission system is planned, built, and operated primarily to accommodate normal services, load customers can (and do) utilize the system for backup purposes. This practice has always existed on the transmission system, but has typically not been quantified. The AESO has attempted to assess the costs attributable to backup loads, at least on a comparative basis to normal loads, through two approaches: using historical diversity and using the Northeast Development regional analysis recently completed by the AESO. (Section 4, page 36)

Request:

Please confirm that in adopting its approaches the AESO has failed to demonstrate the degree to which backup load has contributed to the need for existing facilities. If this cannot be confirmed, please fully explain.

Response:

Not confirmed. The contribution of backup load to the need for existing facilities is embedded in a forecast methodology which incorporates actual metering data. The AESO's analysis of actual metering data in section 4.6.2 of the Application demonstrates the amount of intermittent, short duration loading experienced on the transmission system. The resulting attribution of costs to backup load was validated against the Northeast Alberta Transmission Development analysis, which included specific consideration of backup load.

Reference: From a historical diversity perspective, the transmission system is developed to meet demand and energy requirements forecast by the AESO. The forecast incorporates actual hourly load data for each metering point on the transmission system, for the two most recent years for which data is available. (The demand and energy requirements forecast methodology is described in Appendix B of this application.) As the forecast is based on actual metered load data, it includes the effect of actual utilization of the transmission system for backup loads on an historical basis. Actual metered load data includes both normal and backup loads, and embeds historical levels of load diversity (or, alternatively, load coincidence) in transmission development plans. (Section 4, page 36)

Request:

Has the AESO attempted to develop a load profile of all loads it considers to be standby loads? If so, please describe the characteristics of such load in terms of load diversity or load coincidence.

Response:

No such load profile has been developed. The AESO carried out a preliminary review of the load profiles of some backup services but found such a degree of variability that further investigation was not continued.

Reference: This diversity is apparent in the aggregate load-duration profile of the 240 kV transmission lines analyzed for the 2006 Transmission Cost Causation Update. The weighted average duration curve for loading on the 240 kV lines for 2004 and 2005, as a percentage of the annual peak load on the lines, is provided in Figure 4.6.1. (Section 4, page 37)

Request:

- (a) Please describe how the timeline is maintained (or not maintained) in calculating the duration curve.
- (b) Is the peak load in Figure 4.6.1 the single hour peak of each line or the peak at the time of peak loading on all lines? If the latter, please explain how the sign convention of line flows was considered.
- (c) Please fully describe the calculations undertaken to produce Figure 4.6.1.

Response:

- (a) The timeline is not maintained in calculating the average load duration curve. The curves in Figure 4.6.1 represent the averages of individual load duration curves for each of seventy-nine 240 kV lines. The timelines for the individual load duration curves would be different from each other. Please refer to part (c) below for additional information.
- (b) The peak load in Figure 4.6.1 is the single hour peak of each line. Please refer to part (c) below for additional information.
- (c) For each 240 kV line, the following calculations were performed:
 - (i) The peak loading for each year was calculated as the absolute value of the maximum hourly metered load.
 - (ii) The percentage of peak loading in each hour was calculated by dividing the absolute value of the metered load in each hour by the peak loading determined in (i).
 - (iii) The percentages determined in (ii) were then sorted in descending order from 100% to the minimum percentage of peak loading.

The results of the above calculations are presented on page 17 of the additional analysis of bulk system data, provided on December 13, 2006 as Appendix D to the AESO's 2007 GTA. In the graphs on that page, the load duration curve for each 240 kV line is shown individually.

Finally, for each year, length-weighted average percentages of peak loading were then calculated for each load duration hour in order. That is, the average was calculated over the hour of peak loading on each line, then over the hour of next-highest loading on each line, then over the hour of next-highest loading on each line, and so on over all 8,760 load duration hours, down to the hour of minimum loading on each line. For each load duration hour, the length-weighted average percentage of peak loading was calculated by multiplying the percentage for each line by each line's length, summing the values over all lines, and dividing the total by the sum of all lines' lengths. The length-weighted average percentages of peak loading are presented as the thick grey lines on page 17 of Appendix D, and as thick black lines in Figure 4.6.1.

The data and calculations were 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. 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.

Reference: The vertical line highlights the 5% (438 hour) duration threshold. The horizontal line highlights the average percentage of peak load at the 5% duration threshold, namely 72%. 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).

(Section 4, page 37)

Request:

- (a) Please confirm that the approach adopted assumes that the peak load is “driven” by the standby load. If this cannot be confirmed, please fully explain your answer.
- (b) Please confirm that the AESO is effectively assuming that the standby load is all coincident with the load when the remaining load would otherwise be at peak. If this cannot be confirmed, please fully explain.

Response:

- (a) The approach assumes that the peak load is caused by short duration usage of the transmission system, whether for backup or standby service, other partial requirements service, or for intermittent load service.
- (b) Not confirmed. The approach does not assume that all “normal” loads are at peak in the highest loading hours. For example, a highest loading hour may reflect 100 MW of backup load and 160 MW of normal load, for an actual load of 260 MW. A lower loading hour may reflect no backup load and 170 MW of normal load, for an actual load of 170 MW. In such a case the normal load would be higher in the latter, lower loading hour.

Reference: 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.
(Section 4, pages 37-38 underlining added)

Request:

- (a) Please confirm that the above analysis assumes that cost causation is attributable to peak load. If this cannot be confirmed, please fully explain your answer.
- (b) Please explain the logic employed in assuming that line loading in the hours below the 5% duration “represents normal loads”. Does such logic not also assume that peak line loading coincides with peak load? Please fully explain your answer.

Response:

- (a) Confirmed. Peak loading is a primary cause of maximum stress on transmission lines.
- (b) As defined on page 32 of section 4 of the AESO's 2007 GTA, “normal” services have high load factors, which generally indicate long-duration loads. Such services typically operate near the same load level for much of the time — certainly for more than 5% of the time. The AESO therefore considers that loading above the level defined by the 5% duration threshold would typically not include normal load.

This does not assume that peak line loading coincides with peak load, if peak load refers to peak *system* load. The system load duration curve is included in the graphs on page 17 of the additional analysis of bulk system data, provided on December 13, 2006 as Appendix D to the AESO's 2007 GTA. The system load duration curve is higher and flatter than the curves for almost all individual lines, and for the length-weighted average of individual lines.

The 5% duration threshold assumption for backup service simply assumes that normal loads operate for significantly longer than 5% of the time, and therefore would contribute to bulk line loading for longer than 5% of the time. Short duration loads, such as for backup service, would be expected to contribute to line loading for less than 5% of the time.

Reference: As well, the interconnected capacity of backup loads exceeds the concurrent usage of the transmission system as reflected in system metered data. Based on a review of billing data from June 2005 through May 2006 for low load factor customers, load capacities of less than 5% duration were about 103% of the DTS contract capacities for those customers. Transmission system costs attributed to backup loads should therefore be assessed against an amount of backup load approximately equal to normal load. (Section 4, page 38)

Request:

- (a) Please discuss the nature of use of each of the PODs that in the AESO's Appendix E analysis had a load factor of 0%. How many of these PODs would the AESO characterize as backup loads?
- (b) Please indicate which of the PODs in Appendix E the AESO would characterize as backup loads. Please indicate the sum of their maximum monthly demands over the period of 2004 and 2005.
- (c) Please provide the aggregate hourly load of the PODs identified in (b) above for 2004 and 2005. If full data for 2004 and 2005 is not available, please provide all data that is available.

Response:

- (a) There are 16 PODs in Appendix E with load factors of 0%. Thirteen of these PODs provide backup or standby service for generators connected at the same substation. One POD is for an isolated community. There are no STS contracts at the substations serving the remaining two services. The AESO understands one of these services does have onsite generation. The other is a distribution utility service and the AESO is uncertain of the nature of use.

In summary, the AESO would characterize 14 of the 16 PODs with 0% load factors as backup or standby loads.

- (b) The AESO does not have sufficient information to identify all PODs in Appendix E which would be characterized as backup loads.

The AESO notes that there are 64 substations in Alberta where customers have contracted with the AESO for both load and generation service, which indicates the existence of onsite non-emergency generation. The aggregate monthly demands for PODs at those substations during 2004 and 2005 are provided below.

Sum of Highest Metered Demands by Month
for DTS Contracts at Substations With STS Contracts

Month	2004	2005
January	1,443	1,512
February	1,403	1,777
March	1,609	1,563
April	1,559	1,795
May	1,421	1,762
June	1,412	1,590
July	1,566	1,585
August	1,431	1,585
September	1,438	1,600
October	1,474	1,589
November	1,467	1,314
December	1,697	1,208

The actual amount of backup load interconnected to the transmission system for these services is about 2,053 MW, calculated as the sum over all services of the maximum metered demand for each service over the two-year period.

Please refer to the response to Information Request ADC.AESO-032 for additional information.

- (c) The AESO has not compiled aggregate hourly load data for individual PODs, and doing so would require an unreasonable expenditure of time and effort.

Reference: 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.

The Northeast Alberta analysis suggests a megawatt of backup load should be allocated $52\% \div 135\% = 39\%$ of the amount that would be charged to a megawatt of normal load.

(Section 4, page 38)

Request:

- (a) Please provide a copy of the referenced presentation.
- (b) Please identify the 815 MW and 425 MW figures in the referenced presentation.
- (c) Please confirm that the values quoted are referenced on page 23 (of 35) of the pdf file.
- (d) Please confirm that the 815 MW represents all of the high load factor DTS loads.
- (e) Please describe what is included in high load factor DTS loads (i.e. what is the definition of high load factor).
- (f) Please confirm that the 425 MW is comprised of the largest single low load factor load (250 MW) plus the largest FMM generator (175 MW).
- (g) Please confirm that FMM generator stands for Fort McMurray generator.
- (h) Please describe the nature of the largest single low load factor load and the largest FMM generator.
- (i) Why is the largest single low load factor load larger than the largest generator? Are these two at the same site? If so, should the load not be considered to be a baseload of 75 MW and a standby load of 175 MW?
- (j) Can the AESO confirm that if the largest single low load factor were 125 MW, rather than 250 MW, that the AESO's assessment (in this circumstance) of the AESO's assessment of costs attributable to standby loads would be lowered? If not, please fully explain.

- (k) Can the AESO confirm that the proposed FMM planning approach recognizes the probability of overlapping generator outages?
- (l) Does the proposed planning approach recognize the probability of overlapping low load factor loads where such load is not the “result” of generator outages?

Response:

- (a) Please refer to Attachment IPCAA.AESO-048 (a).
- (b-c) Confirmed. The values appear on slide 23 of the presentation.
- (d) Confirmed.
- (e) The high load factor DTS loads are point of delivery customers that do not have onsite generation (i.e., distribution-type loads) or ISD customers that have insufficient onsite generation to supply their load requirements and must contract DTS to augment supply. (These ISD customers may also have an additional requirement for low load factor DTS for backup purposes to protect for a loss of a generator.)
- (f) Confirmed.
- (g) Confirmed.
- (h-i) The single largest low factor load comprises backup service for the simultaneous loss of three onsite generators. The single largest generator in the Fort McMurray area is located within the Petro-Canada ISD. These customers are not the same.
- (j) The AESO confirms that if any of the values increased or decreased for the loads included in the Northeast Alberta analysis, the outcome of the analysis would be different. However, the Northeast Alberta analysis was reviewed primarily as a consistency check of the AESO’s historical diversity analysis. As stated on page 37 of section 4 of the AESO’s 2007 GTA (in the paragraph immediately following the quoted reference above), “However, the Northeast Alberta Transmission Development may be somewhat unique in its backup load characteristics, and the AESO suggests the historical diversity analysis should generally be relied on for allocating costs to backup service.” The AESO therefore does not confirm that a change to the values in the Northeast Alberta analysis would change the AESO’s assessment of costs attributable to backup loads.
- (k) Confirmed.
- (l) The proposed planning approach presented in the October 2, 2006 stakeholder session does make provision for variations in loads due to changes in processing requirements and generator outputs. This results in approximately 270 MW of additional transmission transfer capability. However, the planning approach for this region has not been finalized and is being reviewed through the Northeast Alberta stakeholder participation process.

Reference: On a very basic level, transmission assets represent by nature a long-term fixed investment. Once planned and built, the cost of the transmission system varies very little based on usage. Its cost should therefore be recovered as a fixed, rather than variable, cost, which would generally lead to classification as a demand-related cost. This conclusion applies equally to both that portion of the transmission system planned for normal load and that portion planned for backup load, since the transmission system remains by nature a fixed asset in both cases. Recovery of the demand-related costs of a transmission system over time traditionally leads to incorporation of ratchet provisions. The nature of backup service does not inherently provide any reason to deviate from this approach. (Section 4, pages 38-39 underlining added)

Request:

- (a) Please fully explain whether the AESO considers that recovery of fixed costs through fixed charges and variable costs through variable charges should be a principle of rate design.
- (b) If the AESO feels fixed costs should be recovered through fixed charges, please fully explain why the AESO has proposed recovering roughly 50% of bulk transmission costs through energy charges?
- (c) Please confirm that TFO charges are generally an equal dollar amount in each calendar month. If this cannot be confirmed, please explain.
- (d) Please confirm that billing determinants related to bulk and local charges are not equal in each calendar month. If this cannot be confirmed, please explain.
- (e) Please provide the billing determinants used in Section 5 Schedule 5.9 by month.
- (f) Please confirm that if TFO wires costs were fully recovered in each month the bulk and local wires charges would be higher in summer months and lower in winter months. If this cannot be confirmed, please explain.
- (g) Please provide the AESO's view as to why it would or would not be appropriate to recover TFO wires costs in the month incurred. Would this not provide a more accurate signal as to the costs of the wires?

Response:

- (a) The AESO considers that fixed costs should be classified as demand- or customer-related costs, and variable costs should be classified as usage-related. In general, such classification is reflective of cost causation and satisfies rate design principles relating to the provision of appropriate price signals and the fairness, objectivity, and equity of rates.

As well, costs are frequently recovered in accordance with their classification. *The Process of Ratemaking* by Leonard Saul Goodman (Public Utilities Reports, Inc., Vienna, Virginia, 1998, p 422) states, "Once costs have been identified in relation to their cause, they are normally allocated to the regulated service in accordance with the units of output which caused them."

However, cost allocation and rate design may also vary from simply following cost classification. *The Process of Ratemaking* also states (p 426), "Electric utility costs, for example, may be assigned in accordance with peak responsibility or time-of-day factors for setting some rates, but the relatively low levels of usage that are swept into these schedules bear little, if any, causal relation to any particular level of company plant." The recovery of fixed and variable costs should therefore be determined through careful and thorough cost analysis, rather than by simply applying a general approach.

- (b) Please refer to the responses to Information Request EnCana.AESO-012 (b) and IPCAA.AESO-008 (b) for additional discussion.
- (c) Confirmed.
- (d) Confirmed.
- (e) Please see attached Schedule IPCAA.AESO-049 (e).
- (f) If TFO charges to the AESO were recovered in the month in which they were billed, the system and POD charges would be higher in the summer months (since billing determinants are lower then) and lower in the winter months (since billing determinants are higher then). However, the AESO expects that TFO costs would not necessarily be equal each month, and is therefore uncertain what the impact would be if actual TFO costs were recovered in the month incurred.
- (g) The AESO considers the current approach of designing rates to recover TFO costs on an annual basis to be appropriate. Wires costs reflect a long-term fixed investment as stated in the quoted reference, and assigning those costs to specific months is more reflective of cash flow than cost causation. Rates are generally not designed to accommodate cash flow.

Furthermore, TFO revenue requirements are established on an annual basis, as has been the traditional practice in Alberta for many years. The annual costs are then recovered through rates based on annual billing determinants. The only exceptions the AESO is aware of are time-of-use and seasonal rates where analysis clearly demonstrates that cost causation in certain periods are materially different and support a monthly or seasonal rate variation for reasons of fairness, objectivity, and equity.

Reference: As already discussed, the transmission system is built to accommodate the existence of backup loads on a forecast basis. Costs are incurred to provide backup service whether or not backup usage actually occurs in any specific period. Backup capacity should therefore be paid for on a basis extending beyond the actual usage period, which can also be accomplished by paying for capacity through ratchet provisions.

A ratchet-based capacity charge is also an equitable approach to recovering the cost of backup service. Assuming occasional use of the backup capacity, the customer will pay for the service throughout the extended ratchet period. If usage of the backup service becomes so infrequent that it does not recur during the ratchet period, the customer no longer pays in accordance with the reduced likelihood of future use of the service.

Although ratchet provisions should apply to capacity utilized for backup service, the capacity charge for such service should be substantially less than the capacity charge applicable to normal service. As discussed earlier in this section, the charges should reflect that the system incorporates a level of diversity and non-coincidence of backup loads, such that a megawatt of backup load should be allocated about 38% of the transmission system charges for a megawatt of normal load. The AESO considers that the system wires charges under the DTS rate proposed in this application appropriately charges for backup service compared to normal service.

(Section 4, page 39)

Request:

Please fully explain how utilizing an NCP demand charge reflects diversity and non-coincidence of backup loads. Please explain what the backup loads are non-coincident to.

Response:

In the quoted reference, diversity refers to differences in timing of backup loads on the transmission system. Reducing the amount of demand-related costs recovered through a capacity charge reflects that the transmission system is planned, built, and operated assuming a level of diversity between customer loads.

Please refer to the response to Information Request IPCAA.AESO-022. As discussed in that response, no matter when a POD's peak load occurs, it will likely coincide with maximum load on some transmission system components. Conversely, for a short-duration backup load, its peak will also not coincide with maximum load on other transmission system components.

Reference: The annual charge for 1 MW of backup load would be about 45% of the annual charge for 1 MW of normal load. Although this is somewhat higher than the 38% of charges for normal load discussed above, the AESO considers this amount to represent an appropriate premium for backup service. Addressing specific concerns arising from backup loads incurs greater administration (through technical studies and ongoing assessments) and greater risk (due to the unscheduled and infrequent nature of backup service) than normal service. The northeast Alberta transmission development process is an example of the extensive work completed to ensure backup loads can be accommodated on the transmission system.

The AESO therefore concludes the proposed DTS rate accommodates the cost and rate design considerations related to the provision of backup service. The contract capacity and ratchet structure of the proposed DTS rate is a reasonable approach which balances facilities costs attributed to backup service and risk mitigation. Based on this conclusion, a separate backup rate is not proposed. (Section 4, pages 39-40 underlining added)

Request:

Please explain the basis for consideration of “greater risk” contributed by backup loads in the context of allocation of embedded costs of transmission assets.

Response:

Please refer to the response to Information Request IPCAA.AESO-038 (a-b),

Reference: The premise of opportunity service is that it should be priced above cost, where cost includes only variable components and not fixed components which would be incurred whether or not the opportunity service was utilized. The AESO therefore examined the variable cost basis for opportunity service rates, as well as other aspects which differentiate DOS 7 Minutes, DOS 1 Hour, and DOS Term rates.

To determine the variable cost for DOS, the AESO first converted all components of its 2007 DTS revenue requirement into \$/MWh amounts as if all were to be recovered on a flat usage (\$/MWh) basis from all DTS customers, as provided in Table 4.7.1.

(Section 4, page 40)

Request:

- (a) Please confirm that in the assessment provided in Table 4.7.1 the AESO has assumed the classification in the AESO tariff is the same as the costs incurred (i.e. fixed charges reflect fixed costs and variable charges reflect variable costs).
- (b) Please confirm that the AESO has acknowledged that bulk transmission costs are 48% variable costs (132.6/272.5).
- (c) Please reconcile the approach taken by the AESO in Table 4.7.1 with the cost classification determined in the TCCU.

Response:

- (a) Table 4.7.1 classifies costs which are billed on a \$/month or \$/MW basis as fixed costs, and costs which are billed on a \$/MWh or percentage of pool price basis as variable costs.
- (b) The classification in Table 4.7.1 is consistent with that in Table 4.5.1 on page 17 of section 4 of the Application, where bulk and local system costs are classified 51.4% as demand-related and 48.6% as usage-related.
- (c) Please refer to the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-008 (b).

Reference: 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 $(1 \text{ MW} \times 1 \text{ month}) + (1 \text{ MW} \times 90\% \times 11 \text{ months}) = 10.9$ 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. (Section 4, page 44, underlining added)

Request:

- (a) Please confirm that the proposed DOS Term rate is nearly 4 times the DOS 1 Hour rate (\$23.79/\$5.99).
- (b) Please confirm that the approach taken to determine the level of the tariff is essentially a “repackaging” of the DTS tariff and not an extension of the DOS tariff. If the AESO does not agree, please fully explain the AESO’s characterization of the DOS Term tariff.

Response:

- (a) Confirmed. In the AESO’s current tariff, the DOS Term rate (\$20.00/MWh) is also four time the DOS 1 Hour rate (\$5.00/MWh).
- (b) Confirmed. As stated on page 2 of section 4 of the Application, the AESO proposed “changes to DOS rate levels to reflect current transmission system costs.” As the DTS rate is cost-based and reflects all load-related costs incurred by the AESO, it provides an appropriate foundation for the DOS rates. As explained on page 40 of section 4 of the application, “...each DTS rate component was then examined to determine if such costs were incurred in providing service to DOS customers.”

Reference: Export rate component charges are proposed to be based on similar component charges for the DTS rate. Similar to the AESO's DOS rate proposals, the AESO proposes that all export rate components will be charged on a usage (\$/MWh or percentage of pool price) basis. The AESO has therefore converted all components of its 2007 DTS revenue requirement into usage charges as if all were to be recovered on such a basis from all DTS customers, as provided in Table 4.8.2. (Section 4, page 46)

Request:

- (a) Please confirm that the AESO proposes to charge a four-week DOS Term load the same contribution to the bulk system as this load would incur on the DTS tariff.
- (b) Please provide the AESO's full justification for the charge noted in question (a) above.
- (c) Please fully explain why the AESO does not propose to impose similar charges under the export tariff.

Response:

- (a) Confirmed.
- (b) As discussed in the opening paragraphs of section 4.7 of the AESO's 2007 GTA, opportunity service is a short-term temporary service provided to customers whose use of the transmission system would not be economically viable at the rates otherwise applicable. Opportunity service should generally be priced above cost, and should also be priced at a level which does not result in cannibalization of other rates to the detriment of other customers on those rates. The AESO considers that when service is required for more than four weeks of the year, it is no longer short-term. If customers wish such longer-term service, they should receive it under the DTS rate which appropriately assesses charges for longer-term service.
- (c) The AESO considers that it does not have a proposed export rate which is comparable to DOS Term. The non-recallable XTS and MTS export rates have different rate components, longer contractual requirements, higher minimum charges, and different curtailment provisions. The opportunity XOS and MOS export rates have different contractual requirements and curtailment provisions. Each rate includes components and provision which are appropriate to the rate, as discussed in the relevant section of the AESO's Application.

Reference: However, the export rates discussed above include a contribution to the costs of the Alberta-British Columbia and Alberta-Saskatchewan inter-ties, which would not be utilized for energy transfers over a merchant line. (If a merchant transaction was scheduled with a corresponding inter-tie transaction for “wheel-through” energy flow into and out of Alberta, the inter-tie would be utilized for the corresponding transaction but not for the merchant transaction itself.) The AESO proposes that both fixed and variable wires costs attributable to the existing inter-ties be excluded from rates applicable to export over merchant inter-ties (Section 4, page 51)

Request:

- (a) Please confirm that the inter-tie costs shown in Figure 4.9.1 include both the B.C. and Saskatchewan ties.
- (b) Please provide the import and export volumes for 2004, 2005 and 2006.
- (c) Please confirm that the AESO has proposed that current use of the system should be the basis for assessing costs of providing service (Section 4, page 9, “Classification of costs is typically based on current usage of the system, and is frequently based on recent historical patterns”). If this cannot be confirmed, please fully explain.
- (d) Please confirm that the AESO proposes to exclude the costs of inter-ties from merchant rates based on the rationale that merchant transactions do not utilize the existing inter-ties. If this cannot be confirmed, please fully explain.
- (e) Please confirm that the role of the existing inter-ties in the current Alberta market structure is to facilitate import and export transactions and there is no explicit reliability enhancing role for the inter-ties in the current Alberta market structure. If this cannot be confirmed, please fully explain.
- (f) Please fully explain what use DTS customers make of inter-ties in the current market structure.
- (g) Please explain the considerations the AESO feels would be necessary to allocate the cost of the existing inter-ties to export transactions in the AESO’s tariff structures.
- (h) Please explain the considerations the AESO feels would be necessary to allocate the cost of the existing inter-ties to import transactions in the AESO’s tariff structures.

Response:

- (a) Confirmed. The description of the costs included for inter-ties in Figure 4.9.1 is provided on page 41 of the *2006 Transmission Cost Causation Update* (provided as Appendix C to the AESO’s 2007 GTA).

(b) Year	Import MWh		Export MWh	
	AB-BC Tie	AB-SK Tie	AB-BC Tie	AB-SK Tie
2004	1,073,472	418,267	968,434	92,940
2005	1,067,997	463,726	985,164	50,493
2006	1,101,207	415,828	460,050	29,415

(c) Confirmed.

(d) Confirmed.

(e) Not confirmed. The Alberta Department of Energy's November 2003 policy paper titled *Transmission Development: The Right Path for Alberta* states:

*Since the ability of inter-ties to exchange electricity in both directions (i.e. import and exports) is essential to a robust wholesale market **and a reliable electric system**, the cost for internal reinforcements and RAS arrangements to allow the inter-ties to function as designed will be allocated to load. (p 9, emphasis added)*

The Alberta Department of Energy's June 6, 2005 policy paper titled *Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable* states:

*Transmission interconnections with neighbouring jurisdictions are essential to a well-functioning power market as they support **reliability**, price stability, generation development and continued economic growth in Alberta.... Supporting export capability of surplus energy could stimulate generation development in the province which would directly enhance system adequacy **and reliability**. (pp 38-39, emphasis added)*

(f) The benefits received by DTS customers from inter-ties are included in the quoted text in part (e) above.

As participants in an electricity market, DTS customers benefit from the inter-ties' contribution to price stability, generation development, and continued economic growth in a well-functioning power market.

As transmission customers, DTS customers benefit from the increased reliability of the Alberta system and operating flexibility provided by inter-ties.

(g) The AESO would consider it necessary to allocate the cost of the existing inter-ties to export transactions if:

- (i) the cost of the inter-ties are demonstrated to be incurred in support of export transactions, and
- (ii) export transactions can reasonably be considered to cause the need for the inter-ties.

- (h) Considerations similar to those provided in part (g) above would apply to the allocation of costs of the existing inter-ties to import transactions. However, the *Transmission Regulation* suggests there should be no allocation of inter-tie costs to importers, in paragraph 30(a)(i) which states:

the just and reasonable costs of the transmission system are wholly charged to owners of electric distribution systems, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff

Reference: 9.6 Determination of Customer Contribution
Customers may be required to contribute toward demand-related costs. The Customer's contribution to demand-related costs will be determined in accordance with this Article 9.6. Otherwise, the Customer must pay all demand-related costs.
The Customer's contribution to the demand-related costs will be calculated as follows:
Customer Contribution = Demand-related costs less the Local Investment
Where:
(a) for a Customer taking service under Rate DTS:
(i) the maximum Local Investment where the TFO provides and owns conventional transformation facilities =
• \$54,500.00/year of DTS contract term for new PODs, multiplied by the Substation Fraction; plus
• \$35,800.00/MW of DTS Contract Capacity/year of DTS contract term for the first 7.5 MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD, multiplied by the Substation Fraction; plus
• \$8,900.00/MW of DTS Contract Capacity/year of DTS contract term for all Contract Capacity over 7.5 MW for both new PODs and increases in capacity of or improvements to the service at an existing POD.
(Section 6, page 31 underlining added)

Request:

Please confirm that "the first 7.5 MW of Contract Capacity" does not refer to the first 7.5 MW of increased capacity at an existing POD but rather to the first 7.5 MW of total capacity at existing PODs. If this cannot be confirmed, please provide a calculation of the maximum local investment of an existing 5 MW POD that expands to 10 MW.

Response:

The AESO confirms that the first 7.5 MW of Contract Capacity refers to the first 7.5 MW of total capacity at new and existing PODs.