

Request:

- (a) Does the AESO consider the Transmission Cost Causation Update (TCCU) to be a traditional cost of service study? Please explain your answer.
- (b) If not, why didn't the AESO conduct a traditional cost of service study?

Response:

- (a-b) The *2006 Transmission Cost Causation Update (TCCU)* is an update to the *Transmission Cost Causation Study* filed as Appendix B to the AESO's 2006 GTA on January 31, 2005. The TCCU addresses various issues that were contentious during the AESO's 2005-2006 GTA and responds to directions from the EUB issued as a result of that proceeding.

The *Transmission Cost Causation Study* used methods consistent with a traditional cost of service study. Since the DTS rate class is the only class responsible for the costs of the transmission system, the *Transmission Cost Causation Study* did not complete the last step of a traditional cost of service study in determining revenue to cost ratios by rate class. The *Transmission Cost Causation Study* was completed to provide guidance regarding rate structure, and not rate level by rate class.

Request:

- (a) Does the AESO agree that its revenue requirement for 2007, focusing particularly on the “wires cost,” arises predominantly from investments made prior to December 31, 2006?
- (b) Has the AESO any evidence that transmission costs to be incurred in the future will be driven by different types of consumer behavior from those that influenced the investments made in Alberta up through 2006? If so, please provide all such studies, investigations and analyses leading to this conclusion.

Response:

- (a) Yes, the majority of the TFOs' wires costs shown in Schedule 2.0 – Revenue Requirement are incurred as the result of investment decisions made prior to 2007.
- (b) The AESO has no specific evidence, and notes that consumer behaviour is only one factor that has influenced investment in the transmission system in the past and will influence investment in the future. Transmission investments will be made to provide safe, reliable, and economic transmission service. Section 2.2.2 of the 2006 *Transmission Cost Causation Update*, provided as Appendix C to the AESO's 2007 GTA, was based on interviews with transmission planners for the purpose of reviewing the factors that transmission planners take into consideration when determining the need for new transmission facilities. The *Update* provided the following summary on page 13 of section 2.2.2:

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

- Preamble:** Reference the NERA Report “Assessment of AESO Transmission Cost of Service Analysis, prepared for the AESO and dated October 31, 2006 (NERA Report). The NERA Report notes that use of NCP for demand-related transmission cost allocation is not common.
- (a) Please explain why a departure from the common industry standard allocation methodology is needed in Alberta?
 - (b) What is so unique about the Alberta transmission system that this radical departure from the common industry standard is justified?
 - (c) How much weight does the TCCU place on historical cost drivers, i.e., load that drove the need for the transmission facilities currently in place? Please explain your answer.
 - (d) Please provide all documents relating to consultation and discussion with transmission planners regarding the cost drivers for transmission facilities. Please include documents regarding the cost drivers for the transmission lines that are already in place.
 - (e) NERA’s Executive Summary, page I states that it was “asked to provide information on methods used to functionalize, classify and recover transmission wires costs in other jurisdictions, including regions with transmission systems similar to those in Alberta”. Please provide all documents collected in the process of completing this task, including any notes or memoranda discussing the results of the information gathered.
 - (f) NERA’s Executive Summary page ii states “Underlying the AESO proposal to combine Bulk and Local costs is the assumption that bulk facilities tend to evolve into local facilities over time and in areas experiencing load growth.” Please provide support for this assumption.
 - (g) NERA’s Executive Summary page ii states that the AESO’s detailed analysis suggests that Bulk and Local planning differ in many respects. Please identify each area in which Bulk and Local planning by the AESO differ.
 - (h) NERA’s Executive Summary page ii states that classification of a portion of transmission costs to energy is a standard industry practice. Please provide support for this statement including all research conducted, documents collected and analysis of the data. Please provide a list of all jurisdictions where any portion of transmission costs is classified as energy-related.
 - (i) NERA’s Executive Summary page ii states that the energy-related portion of Bulk transmission costs are the costs assumed to be incurred to reduce losses. Please provide support for this assumption. Please also confirm that the cost of losses is recovered from generators and not through the DTS tariff. Since the cost of losses is recovered from generators and not from load, please confirm that it would be reasonable

- to recover the costs assumed to be incurred to reduce losses from generators and not from DTS customers.
- (j) NERA's Executive Summary page iii states that the adjustment to the demand-related share of Bulk costs to shift some of those costs to the energy rate component is not justified. Please agree or disagree with this statement and explain your answer.
 - (k) NERA's Executive Summary page iii states that the Alberta transmission system users should face incentives to carefully control loads in all hours. The AESO's NCP approach essentially provides an incentive for users of the Alberta transmission system to minimize their usage of the system in all hours. Please agree or disagree with this statement and explain your answer.
 - (l) NERA's Executive Summary page iv states that the use of NCP for demand-related transmission cost allocation is not common, but Nova Scotia Power uses a combination of NCP and CP for this purpose. Please identify every other jurisdiction where NCP is used to allocate bulk transmission cost.
 - (m) NERA's Executive Summary page iv states that a disadvantage of the AESO's proposal to use ratcheted NCP to recover demand-related Bulk system costs is that the incentive to control load will be reduced in hours unlikely to set the billing capacity, although those may be hours when the lines affected by the customer's load are stressed. Please agree or disagree with this statement and explain your answer.
 - (n) Please confirm that under the AESO's proposal to use a ratcheted NCP demand billing determinant based on a 90% factor applied to the contract capacity and the highest demand in the past 24 months means that once a customer's load is high enough to trip the ratchet in one month, the customer has no incentive to minimize load below the level that tripped the ratchet in the following 24 months. Please comment on the impact of this with regard to price signals to customers regarding the efficient use of the transmission system.
 - (o) NERA's report page 2 states that the AESO studies were intended to identify the cost causation of the several elements of the transmission system. However, in using the study's results for rate design, the AESO recognized that its proposal departed from cost causation. Please explain this statement, i.e. how, in the AESO's view, does its rate design proposal depart from cost causation.
 - (p) NERA's report page 4 states that energy related costs were defined as those associated with upgrading the line to an optimal configuration that minimizes costs, including losses. Please identify and quantify the costs other than for losses, referred to in this statement.
 - (q) NERA Appendix. Please explain how the selected utilities included in the Appendix were chosen, i.e., what were the criteria? Were any other utilities' practices examined? If the answer is yes, provide all information collected for each utility. If the answer is yes, why were those utilities excluded from the Appendix?
 - (r) NERA Report, page 10 states that in the case of utilities that did not classify transmission as entirely demand-related and allocated using 12CP, the cost method and rate design are not exclusively focused on the historical factors driving transmission investment but rather on the current use of the system. Please provide a complete list of

these utilities and indicate whether historical cost drivers were considered in addition to current use of the system.

- (s) The NERA Report at page 13 indicates that, historically, system peak demand drove the need for bulk system expansion. Does the AESO agree that, historically, the cost driver for bulk transmission system expansion was system peak demand? If the answer is yes, when did this relationship end?
- (t) Does the AESO believe that, in the past, expansion of the transmission system was driven by different factors and load growth at different times of the day and year, depending on location? Would it be possible to consider both the historical reasons as well as current factors that drive the need for expansion of the transmission system? If not, why not? If so, what would the implications be for cost causation and rate design?
- (u) The NERA Report at page 13 states that they are not aware of any jurisdiction in North America that classifies and allocates costs based on the factors that affected historical system expansion decisions without regard to the current use of the system. Please confirm that the NERA Report also states that most jurisdictions classify transmission cost as 100% demand related and allocate the cost on some type of peak demand method. Please agree or disagree that, ergo, those jurisdictions must consider that the use of a system peak allocation methodology reflects current use of the system as well as historical cost drivers.
- (v) The NERA Report at page 17 states that the AESO's proposed billing determinant dampens important customer incentives for efficiency. Please agree or disagree with this statement and explain your answer.

Response:

- (a) The AESO draws a distinction between cost of service and rate design. To the AESO's knowledge, there is no common industry standard allocation methodology within cost of service studies for transmission systems as a stand-alone function. Rate design for transmission systems may be based on cost of service studies that were conducted on the combination of generation and transmission systems and these result in rates designed on 1 CP, 12 CP, or other methods. The *Transmission Cost Causation Study* and its subsequent *Update* are studies that review transmission costs on their own, and there is no "common industry standard allocation methodology" for cost of service studies for transmission systems. Therefore, Alberta has not departed from any "common industry standard allocation methodology" regarding cost of service studies.
- (b) Please refer to part (a) above as well as the original *Transmission Cost Causation Study* and the *Update*.
- (c) The *2006 Transmission Cost Causation Update* considers existing practices regarding the expansion of the transmission system. The cost of providing transmission service is not linked to historical practices that are no longer relevant. For example, generation and transmission were at one time classified on the basis of 1 CP when winter peaks were predominant and drove the need for generation capacity. As summer peaks grew, classification in Alberta was revised to a 3 winter/9 non-winter basis to recognize that the winter peak no longer as dominant a cost driver. Cost drivers specific to the transmission system have similar changed over time and, in light of these changing conditions, the

AESO considers that existing cost drivers for system expansion are appropriate for the determination of cost causation.

- (d) Discussions with system planners were oral, and are summarized in section 2.2.2 of the *2006 Transmission Cost Causation Update*.
- (e) The NERA Report summarizes the information gathered and the assumptions made during the completion of their task. The AESO did not separately collect such documents.
- (f) Please refer to section 4.2 of the original *Transmission Cost Causation Study* filed as Appendix B to the AESO's 2006 GTA on January 31, 2005.
- (g) Please refer to section 4.1 of the original *Transmission Cost Causation Study*.
- (h) Please refer to section IV.A. of the NERA Report.
- (i) Please refer to section IV.A. of the NERA Report. The AESO confirms that the cost of losses is recovered from generators, importers, and opportunity services as required under Section 22 of the *Transmission Regulation*, A.R. 174/2004. The classification of the bulk transmission system costs in the *Transmission Cost Causation Study* was thoroughly reviewed in the AESO's 2005-2006 GTA, and in Decision 2005-096 the EUB stated (p 24), "Given the above, the Board is prepared to accept that some portion of embedded wires costs are energy related."
- (j) Please refer to the response to Information Request IPCAA.AESO-013 (c).
- (k) Please refer to the response to Information Request IPCAA.AESO-028.
- (l) The AESO has not surveyed every other jurisdiction's allocation of bulk transmission costs. Please refer to the appendix to the NERA Report in which NERA summarizes methods used in selected jurisdictions.
- (m) Please refer to the response to Information Request TCE.AESO-011 (d).
- (n) Not confirmed. Please refer to the response to Information Request EnCana.AESO-018 (b).
- (o) Please refer to the responses to Information Requests BR.AESO-002 (b) and EnCana.AESO-012 (b).
- (p) Other costs that may be minimized through an optimal configuration may include avoidance of additional expenditures for future capacity upgrades, reduction of inventory costs, savings due to standardized engineering and design, and reduction of variable transmission costs such as ancillary services.
- (q) The utilities were selected by NERA. The AESO is not aware of the selection criteria used.

- (r) The AESO has not surveyed other utilities' approaches to classification and allocation of transmission costs. Please refer to the appendix to the NERA Report in which NERA summarizes methods used in selected jurisdictions.
- (s) The AESO understands that 1 CP was used for classification of generation and transmission plant in Alberta. This approach was discontinued around the mid-1980s and replaced with a 3 winter/9 non-winter approach, which was in turn discontinued for the transmission system at the time of industry restructuring in 1996.
- (t) The AESO believes that, in the past as today, transmission system expansions were generally required to avoid violation of limits with respect to one or more of thermal capacity, voltage, or stability, and to meet capacity and service location requirements of customers. However, as discussed on page 11 of section 4 of the AESO's 2007 GTA, the nature of the transmission system has changed from the era of centrally-planned generation to the current market-based model, and the location of generation with respect to load has affected usage patterns for transmission components. Although the reasons for expansion may not have changed, the factors which lead to those reasons has changed considerably as the transmission system has developed over time. Allocating current costs of the transmission system based on historical factors would lead to a disconnect between cost causation and rates, and would likely result in a price signal that would not result in the most efficient use of the transmission system.
- (u) The AESO considers that many factors influence decisions regarding the allocation and classification of transmission costs, and declines to speculate on the basis for such decisions in other jurisdictions. Please refer to the appendix to the NERA Report in which NERA summarizes methods used in selected jurisdictions.
- (v) Please refer to the response to Information Request TCE.AESO-011 (d).

Request:

- (a) Has the AESO conducted an analysis of the merits of using some definition of a peak allocation method versus the proposed NCP method?
- (b) If so, please provide a copy of the analysis, including all workpapers.
- (c) If the AESO did not conduct such an analysis, please explain why not?
- (d) If the answer to part (a) of this data request is no, please prepare an analysis of the advantages and disadvantages of using a peak allocation method versus the proposed NCP method. The peak allocation method does not have to be limited to a 1 CP method. It could include a summer/winter peak, a 12 CP or the hours above 90% of the system peak.
- (e) Please provide statistical support that NCP demand will more accurately allocate bulk transmission costs than a CP demand method.

Response:

- (a-c) The AESO has not conducted an analysis of the merits of using a peak allocation method. A peak allocation method would be appropriate only if transmission system loading varied directly with system load. The AESO's examination of the relationship between 240 kV line loading and system peak, as discussed in section 4.3.2 and in Appendix D of its Application, did not reveal any significant correlation that would support further analysis.
- (d) The overwhelming disadvantage of using a peak allocation method is that it would not lead to recovery of costs in the manner in which they are caused, since transmission system loading does not correlate to system load.
- (e) The AESO cannot provide statistical support that NCP demand will more accurately allocate bulk transmission costs. As discussed on page 38 of the *2006 Transmission Cost Causation Update* (provided as Appendix C to the AESO's 2007 GTA), "It is impractical to correlate maximum load at each POD with maximum circuit loading for each circuit due to the volume of POD's and circuits."

Request:

- (a) Does the AESO agree that peak demands of large groups of customers are a cost driver of the bulk transmission system in Alberta? Please explain your answer.
- (b) Does the AESO believe that a DTS customer's individual monthly highest demand is more or less likely to be correlated to the peak demands of South or Central Alberta than that customer's peak demand at the time of the 12 monthly provincial peaks? Please explain your answer.
- (c) Does the AESO agree that a billing determinant for DTS based on some measure of regional peak demand would be indicative or representative of the demands driving the need for expanding the bulk system? Please explain your answer.
- (d) Assuming that the Board would decide to use some measure of coincident peak as a billing determinant for a portion of the DTS tariff, please describe, with as much specificity as possible, the most cost-based measure of such demand to use.

Response:

- (a) The AESO considers that peak demands of all customers are a cost driver of the bulk transmission system. The costs of the transmission system are primarily demand-related, as detailed in the original *Transmission Cost Causation Study* and in the *2006 Transmission Cost Causation Update*, and customer demand would therefore be a cost driver.
- (b) Over all DTS customers, a customer's individual monthly peak demand would generally be expected to exhibit reasonable correlation with peaks of the Alberta Interconnected Electric System (AIES) as a whole, since the sum of all customers' demands constitute the system demand.

As the AIES is broken into smaller subsystems (such as South or Central regions), the correlation of a customer's demand to the subsystem demand would be expected to weaken. Over all DTS customers, a customer's individual peak demand would therefore be less likely to correlate to the peak demand of South or Central Alberta than to the AIES system peak.

Ultimately, at the individual transmission system component level as discussed in section 4.3.2 of the AESO's 2007 GTA, and over all system components and all DTS customers, a customer's individual peak demand would be expected to exhibit very weak correlation with system component peak demands. Since individual transmission system components experience peak demands at different times (as illustrated in Figure 4.3.5 on page 10 of section 4.3.2), a single DTS customer's peak may correlate well with some system components and poorly with others. Over all customers and all components, however, average correlation would be expected to be very weak.

- (c) No, the AESO does not believe coincidence with a regional peak demand would be representative of the cost drivers on the bulk system as a whole.

First, the bulk system interconnects all the regions of Alberta, and a regional peak demand may not be representative of demands driving interregional expansions.

Second, a regional peak demand may be representative of demand driving expansion of the bulk system within the region, but may not be representative of demands driving expansions in other regions.

Since the bulk system both moves power from generation-surplus regions to load regions and provides support between regions during contingencies and special operating conditions, the bulk system should be considered as a single system that integrates the regional subsystems. The billing determinants for the bulk system should therefore be representative of demands on the bulk system as a whole, not just of those on a regional subsystem.

- (d) The only peaking pattern exhibited in the AESO's analysis of bulk transmission lines is a very weak "on-peak" period from about 1:00 AM to about 1:00 PM, as illustrated in Figure 4.3.5 on page 10 of section 4.3.2 of the AESO's 2007 GTA. Within that period, average weighted line loading was about 101% of the average over all hours. Within the corresponding "off-peak" period from about 1:00 PM to about 1:00 AM, average weighted line loading was about 99% of the all-hours average.

The AESO therefore suggests that the only coincident peak measure that should be considered would be a slightly higher charge for peak demand from about 1:00 AM to about 1:00 PM and a slightly lower charge for peak demand from about 1:00 PM to about 1:00 AM. However, given the very small differences between the average weighted line loadings in the two periods, the AESO does not consider the distinction to satisfy considerations of practicality and simplicity.

Request:

- (a) What customer behavior contributes to the need for additions and upgrades to the bulk transmission system in Alberta?
- (b) Given its response to part (a) of this data request, what, in the AESO's view, are the implications for DTS rate design?

Response:

- (a) Please refer to the response to DUC.AESO-001 (d) for more information regarding system conditions that are examined in planning for additions and upgrades to the bulk transmission system. Also, as stated in the response to IPCAA.AESO-006 (b), the AESO considers that consistent, long-term, and predictable usage patterns contribute to enabling efficient development of the bulk and local systems.
- (b) The AESO considers that a charge which includes energy, ratchet, and contract minimum provisions provides a clear signal that customers should avoid demand peaks and should strive for as flat a load profile as practical. This will allow the AESO to develop the transmission system in an orderly and efficient manner, to operate the transmission system effectively and to avoid violation of thermal capacity, voltage and stability limits. For more information please refer to the responses to IPCAA.AESO-006 (a-b), IPCAA.AESO-028 and ADC.AESO-007 (c).

Preamble: Assuming the AEUB approves the AESO proposal to allocate and bill the entire demand-related cost of the bulk transmission system based on NCP demand, please respond to the following questions regarding the impact on customer behavior.

Request:

- (a) Does the AESO agree that its proposal places the same cost burden on off-peak as on-peak loads? Please explain your answer.
- (b) Does the AESO agree that its proposal will eliminate the incentive to shift load from on-peak to off-peak periods? Please explain your answer.
- (c) Does the AESO agree that the proposed method eliminates the incentive to minimize additional transmission capacity provided by the current allocation and billing method? Please explain your answer.

Response:

Although the AESO proposes to recover some of the cost of the bulk transmission system based on NCP demand, that cost is not the entire cost of the bulk system nor even the 81.5% of the bulk system cost determined to be demand-related in the cost causation studies prepared by PS Technologies. Rather, the AESO proposes to bill 51.4% of the bulk system cost on NCP demand, as discussed in section 4.5.1 of the Application.

- (a) Agreed. 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. Thus no matter when a POD's peak load occurs, it will likely coincide with maximum load on some transmission system components.
- (b) Agreed. There should be no incentive to shift loads from one period to another when load in any period will likely coincide with maximum load on some bulk transmission system components.
- (c) The AESO does not agree.

The proposed non-coincident peak billing method will encourage customers to avoid demand peaks in every hour and strive for as flat a load profile as possible, which would result in the most efficient use of the bulk transmission system as discussed in the responses to Information Requests IPCAA.AESO-006 (a-b) and IPCAA.AESO-028.

The current coincident peak billing method encourages customers to avoid the time of monthly Alberta system peak only. Load in any other hour incurs no bulk system-related charges, even though it is likely that some, but not all, bulk system components will be at

or near maximum loading conditions in every hour of the day and every month of the year. The AESO therefore considers that coincident peak billing does not currently provide an incentive to appropriately minimize the addition of transmission capacity to the bulk system.



Request:

- (a) Does the AESO agree that the method chosen to allocate the cost of and bill for the bulk transmission system should create an incentive for customers to utilize the system as efficiently as possible? Please explain your answer.
- (b) Please discuss the incentives for efficient use of the bulk transmission system provided by the AESO's proposed cost allocation and billing method.

Response:

- (a-b) Please refer to the responses to Information Requests IPCAA.AESO-006 (a-b) and IPCAA.AESO-028.

Preamble: By adopting an energy allocation for a significant portion of bulk transmission costs the AESO tariff effectively signals that load in any hour of the year equally impacts the requirement for future transmission upgrades.

Request:

- (a) Does the AESO agree or disagree with this statement? Assuming that the AESO agrees with the statement, does the AESO agree or disagree with the resulting price signal?
- (b) Does the AESO agree that the use of individual customer maximum demands, irrespective of when those demands may occur, as the billing determinant for DTS, conveys a signal that all hours of the year equally impact the requirement for future transmission upgrades? Please explain your answer.

Response:

- (a-b) After extensive review of cost causation on the bulk transmission system, the AESO concluded, "Load in every hour is therefore important," as stated on line 46 on page 11 of section 4 of the AESO's 2007 GTA. The adoption of non-coincident demand (\$/MW) and usage (\$/MWh) components in the DTS rate, in approximately equal proportions, both reflect this conclusion.

Please refer to the responses to Information Requests BR.AESO-002 (b), IPCAA.AESO-016 (a-b), and IPCAA.AESO-028 for additional discussion.

Request:

Please confirm that maintenance on transmission lines is generally scheduled to avoid on-peak hours during system peak periods.

Response:

As a standard practice, the AESO conducts an assessment of system performance to identify any risks or performance issues associated with a proposed maintenance schedule. Some assessments indicate that certain transmission elements should not be scheduled out of service during system peak periods. Other assessments indicate that certain transmission elements can be scheduled out of service during system peak periods, but should not be scheduled out of service during other periods due to other considerations relevant to the transmission element in question.

Preamble: The AESO has presented a significant amount of qualitative and quantitative analysis that purportedly proves that coincident peak demand is not related to the times of maximum stress on the bulk transmission system.

Request:

Please provide a similar amount and type of analysis showing that the use of NCP demand is a better fit (than some measure of coincident peak demand) with the maximum stress on the transmission system.

Response:

The *2006 Transmission Cost Causation Update* illustrated that transmission constraints occur throughout the year and that the constraints are not simultaneous to AIL peak. The time of constraints on transmission system components occurs throughout the year depending on the location and the nature of the constraint, as discussed in section 2.2.2 of the *Update*. Therefore, the link between the time of coincident AIL peak and the time of maximum stress on transmission system components is weak. Rates designed on the basis of coincident peak will send the price signal that demand is only important at the time of system peak load, and such a price signal is erroneous and does not provide an incentive to control demand during other periods.

As concluded on page 13 of the *Update*:

Transmission planning is driven by a large number of independent factors such as the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta.

Transmission constraints on the transmission system near a generator will generally occur when the generator is operating at its maximum output, while constraints on the transmission system near a load centre will generally occur when the load is at its maximum (NCP). The *Transmission Cost Causation Update* indicates that maximum stress can occur throughout the year and is driven by a large number of independent factors. The only one of these parameters that customers control is the level of their own load (NCP).

Therefore, from the perspective of rate design, billing demand based on NCP load is the best price signal for customers to manage their load at all times, in order to minimize the need for transmission system expansion.



Request:

Please indicate the month of the overall Alberta system peak demand in each of the past five years.

Response:

The overall Alberta system peak demand for the last five calendar years 2002 to 2005 has occurred in December of each year. The overall Alberta system peak demand for the calendar year 2006 occurred in November.

Request:

- (a) Does the AESO have knowledge of any Province or states that experiences system peak demand in the summer months during some years and during winter months in other years?
- (b) If the answer to part (a) of this data request is yes, please provide a list of those Provinces and jurisdictions.
- (c) If the answer to part (a) of this data request is yes, please provide the method used in those jurisdictions to allocate the cost of bulk transmission lines.

Response:

- (a-c) The AESO does not have knowledge of other jurisdictions with respect to the timing of annual peak load.



Request:

Reference the AESO 2007 General Tariff Application Table 2.1.2 Commodity Prices. Please provide a copy of all documents and workpapers provided by EDC Associates Inc. with regard to the forecast pool price, gas price and average market heat rate.

Response:

EDC Volume 6 Issue 34-A and EDC Volume 6 Issue 34-B are attached as ADC.AESO-014-A and ADC.AESO-014-B respectively.

Request:

The AESO 2007 GTA Section 4, page 2 states that there is an overall decrease of 3.2% in the DTS rate and an overall decrease of 8.1% in the STS rate. Please reconcile those numbers with the numbers shown in Table 4.0.1, which show an overall decrease of 2.7% in the DTS rate and a decrease of 6.0% in the STS rate.

Response:

The numbers shown in Table 4.0.1 are correct, and reflect the calculations in Schedule 5.10 in section 5 of the Application.

The numbers in the text at lines 27-30 on page 2 of section 4 are incorrect. The text should read:

The net impacts on rates of the changes detailed in this Application are an overall decrease of 2.7% in the Demand Transmission Service (DTS) rate and an overall decrease of 6.0% in the Supply Transmission Service (STS) rate. However, not all components of the DTS and STS rates are affected equally, and changes by component are summarized in Table 4.0.1.

Reference: Reference the AESO 2007 GTA Section 4, page 12.

Request:

Please explain why the AESO did not rely on the NERA review as part of its evidence.

Response:

The AESO contracted NERA to conduct a review of the bulk system analysis and conclusions in the *2006 Transmission Cost Causation Update*. Although the AESO's experience supported the *Update's* cost functionalization and classification, some stakeholders questioned the validity of its approach. The AESO expected an expert review by NERA would identify any areas in the *Update* which were inconsistent with industry practice or otherwise questionable. Further investigation of areas which were identified would then be conducted by PS Technologies (author of the *Update*) or the AESO, rather than by NERA. As well, evidence resulting from any further investigation would be prepared by PS Technologies or the AESO and filed by the AESO.

However, the *NERA Assessment* (provided in response to Information Request BR.AESO-001) found the functionalization and classification proposed in the *Update* to be reasonable. NERA did offer suggestions for a few refinements to the AESO's proposed rate design, and those suggestions were consistent with concerns raised by stakeholders during the AESO's 2007 rates consultation. The AESO was examining various approaches to cost allocation for its proposed 2007 rate design when the *NERA Assessment* was finalized, and ensured that the filed rates addressed any concerns raised by NERA.

The 2007 rates evidence was therefore developed, prepared, and filed by the AESO and PS Technologies. The NERA Assessment supports the reasonableness of this evidence, but this evidence stands on its own, and therefore the AESO did not believe it was necessary to use the NERA Assessment directly in addition to the evidence already available.



Reference: Reference the AESO 2007 GTA Section 4, page 12.

Request:

Please explain why the Electric Utilities Act would preclude a regional cost analysis of the bulk transmission system line loading.

Response:

Please refer to the response to Information Request TCE.AESO-014 (a-b).



Reference: Reference the AESO 2007 GTA Section 4, page 13.

Request:

Please confirm that the AESO did not intend the word peak to be included on line 9.

Response:

Not confirmed. The words “peak demand” are used as a synonym for “highest Metered Demand” which appears in the definition of Billing Capacity in Rate DTS in section 7 of the AESO’s 2007 GTA as well as in the AESO’s 2006 tariff. The peak demand is that of the individual customer, not of the transmission system.

(For clarity, ADC has advised the AESO that the reference intended in this request appears at line 30 on page 12 of section 4 in the PDF version of the AESO’s 2007 GTA.)



Reference: Reference the AESO 2007 GTA Section 4, page 18.

Request:

Please confirm that the table labeled Table 4.5.1 should be labeled Table 4.3.8.

Response:

The table is correctly labeled Table 4.5.1, in accordance with the convention in section 4 of using the sub-section number as the first two digits of table and figure numbers.

However, the reference to the table is incorrect in the sentence which follows it, at lines 24-25 on page 17 of section 4. That sentence should read in part:

The system charge resulting from the functionalization and classification of Table 4.5.1 is provided in Schedule 5.5 in section 5 of this application....

The reference to the table is also incorrect in the sentence at lines 26-27 on page 22 of section 4. That sentence should read in part:

The POD charge resulting from the functionalization and classification of Table 4.5.1 and the above discussion is provided in Schedule 5.5 in section 5 of this application....



Reference: Reference the AESO 2007 GTA Section 4, page 25.

Request:

Please provide the electronic spreadsheets with all formula intact used to derive the DTS Bill Impact Comparison by POD shown on Table 4.5.2 and in Appendix E.

Response:

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



Reference: Reference the AESO 2007 GTA Section 4, page 25.

Request:

Please describe how the AESO arrived at the number 300% for the point at which the increase should be capped.

Response:

As stated on lines 6-9 on page 28 of section 4 of the AESO's 2007 GTA, "As quoted from Decision 2005-132 above, the EUB commented that 'impact...in excess of 400%...[could be] considered...unreasonable.' (This comment was in the context of the one-year change from 2005 to 2006 rates.)"

The AESO therefore considers that the cap should be substantially less than 400% over a single rate change. The AESO also proposes that the cap apply for a limited time (to December 31, 2008), and therefore needs to be high enough such that the bill impact on expiry of the cap is reasonable as well. Finally, the AESO considers that the cap should apply to as few customers as possible to minimize subsidization between customers.

The AESO considers that a maximum increase of 100% over a single rate change satisfies these considerations. Over two rate changes (from 2005 to 2006 rates and from 2006 to 2007 rates), a maximum increase of 100% per rate change results in a total maximum increase of 300% as illustrated below.

| | 2005 Rate | 2006 Rate | 2007 Rate |
|---|-----------|-----------|-----------|
| DTS Bill (\$/month) | \$2,500 | \$5,000 | \$10,000 |
| DTS Bill Increase, Year Over Year (\$) | — | \$2,500 | \$5,000 |
| Percentage Increase, Year Over Year | — | 100% | 100% |
| DTS Bill Increase, Total Over 2005 (\$) | — | \$2,500 | \$7,500 |
| Percentage Increase, Total Over 2005 | — | 100% | 300% |

Request:

The AESO 2007 GTA Section 4, page 35 describes the rate structure of the AESO back-up service rate wherein for load factors above 10%, higher charges would be incurred on the backup service rate than on the regular DTS rate. Please explain why the AESO does not consider this a sufficient price signal to give customers an incentive to manage backup service requirements and prevent significantly increased usage.

Response:

A usage (\$/MWh) charge as initially proposed would discourage longer-duration backup loads, but would not discourage significant utilization of the rate for short-duration backup loads. In fact, a rate with only \$/MWh charges would provide little, if any, incentive for a customer to manage very short-duration backup loads, as backup loads of a few hours duration would incur minimal cost even at very high MW levels. The AESO would therefore expect the incidence of such short-duration loads to increase, giving rise to risks of voltage deviations or tripping of system elements.

As well, a charge based solely on usage would not be reflective of the costs imposed on the transmission system by backup loads. As discussed in section 4.6.2 of the AESO's 2007 GTA, the AESO determined that a megawatt of backup load should be allocated about 38% of the transmission system charges for a megawatt of normal load. A wholly usage-based rate would not allocate such costs to a very short-duration backup load.

Reference: Reference the AESO 2007 GTA Section 4, page 35.

Request:

Please indicate whether the AESO would consider offering backup service for a temporary period of time so that the impact of the service could be assessed to determine whether the AESO's concerns are well founded.

Response:

The AESO assumes the request is with respect to a backup rate based on a usage (\$/MWh) charge which generates equivalent revenue as the DTS rate at a 10% load factor. If so, the AESO would not consider it appropriate to offer such a rate, for a temporary period or otherwise. As explained in the response to Information Request ADC.AESO-023, a charge based solely on usage would not be reflective of the costs imposed on the transmission system by backup loads and therefore the AESO does not believe such a rate should be offered.

Reference: Reference the AESO 2007 GTA Section 4, page 35.

Request:

Is the AESO aware that it is common industry practice to limit backup service rates to customers with on-site generation and that this condition is not considered arbitrary or discriminatory?

Response:

The AESO understands that this practice is common but not universal. For example, the New York Public Service Commission, in *Opinion and Order Approving Guidelines for the Design of Standby Service Rates, Opinion No. 01-4* dated October 26, 2001 (pp 6-7), states:

The Standards reflect the premise that standby delivery service is sufficiently different from full delivery service to justify some difference in treatment, but that not enough valid cost data exists for OSGs [on-site generators] to justify creation of a separate service classification or classifications for standby service. Until such time that significant data exists on the operation and cost causation of various standby service customers to justify the creation of a separate standby delivery service rate classification, the Guidelines provide that standby delivery service will be provided as part of the otherwise applicable full-requirements class tariff. That applicable service class will be based on the standby customer's maximum potential, or contract, demand. However, as explained below, the unique usage characteristics of standby customers, by virtue of these customers' intermittent and more random reliance on the delivery system, will be recognized through rate design.

Rates applicable only to customers with onsite generation are also not provided in Texas, according to *Rate Structures for Customers With Onsite Generation: Practice and Innovation* by L. Johnston, K. Takahashi, F. Weston, and C. Murray (National Renewable Energy Laboratory, Golden, Colorado, December 2005, p 19):

In Texas, where transmission and distribution utilities (TDUs) have no tariffs specifically for DG [distributed generation] standby service, customers are charged under full tariffs for the power they take from the grid and are subject to demand ratchet provisions.

Rate Structures for Customers With Onsite Generation (p 11) also comments on the general comparability of rates for backup service and normal service:

In their general characteristics, the rates for partial-requirements customers look the same as those for full-requirements customers. The same components of the network provide the two services, so standby and related rates are typically broken out along the traditional lines suggested by the preceding discussion. There are fixed, recurring customer charges; demand charges for capacity

(generation, transmission, and distribution, bundled or unbundled) that may or may not vary with demand; and energy charges for the actual amounts of electricity purchased.

Reference: Reference the AESO 2007 GTA Section 4, page 37.

Request:

Please provide all analysis including electronic workpapers and assumptions used to develop the chart in Figure 4.6.1.

Response:

The data and analysis for Figure 4.6.1 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.



Reference: Reference the AESO 2007 GTA Section 4, page 37.

Request:

Please provide support for the assumption that line load above the 5% duration threshold represents backup load. Please confirm that some portion of the line load above the 5% duration threshold would include what the AESO has deemed “normal” load, i.e., non backup load.

Response:

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

The AESO would agree that some portion of the line load above the 5% duration threshold would likely include “normal” load, and also expects that some portion of the line load below the 5% duration threshold would likely include backup load.



Reference: Reference the AESO 2007 GTA Section 4, page 37.

Request:

Please provide support for the assumption that 72% of peak line loading translates into 72% of the transmission system cost.

Response:

As determined in the original *Transmission Cost Causation Study* (provided as Appendix B to the AESO's 2006 GTA filed on January 31, 2005), approved by the EUB in Decision 2005-096, and confirmed in the *2006 Transmission Cost Causation Update* (provided as Appendix C to the AESO's 2007 GTA filed on November 3, 2006), costs of the bulk and local transmission system are classified primarily as demand-related. Costs would therefore generally reflect the level of loading on the transmission system.

Request:

The AESO 2007 GTA Section 4, page 37 states that “The transmission system is generally planned on a 95% probability of load coincidence.” Does this statement refer to load coincident with the system peak? Please reconcile the AESO’s position that the time of maximum stress on the transmission system is not correlated to the system peak load with this statement.

Response:

The statement refers to the coincidence of loads with each other, relative to the transmission component being planned. Transmission system components are planned to accommodate load at the time of maximum stress on the component. If that maximum stress occurs at the time of load coincidence, a 95% probability of load coincidence is assessed. If maximum stress occurs at a time other than that of load coincidence (nighttime or shoulder period loading, for example), no probability of load coincidence needs to be assessed.



Request:

The AESO 2007 GTA Section 4, page 38 states that “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 a variable, cost, which would generally lead to classification as a demand-related cost.” Please reconcile this statement with the AESO proposal to recover 28.7% of the total transmission wires costs on an energy-related basis.

Response:

Please refer to the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-008 (b).

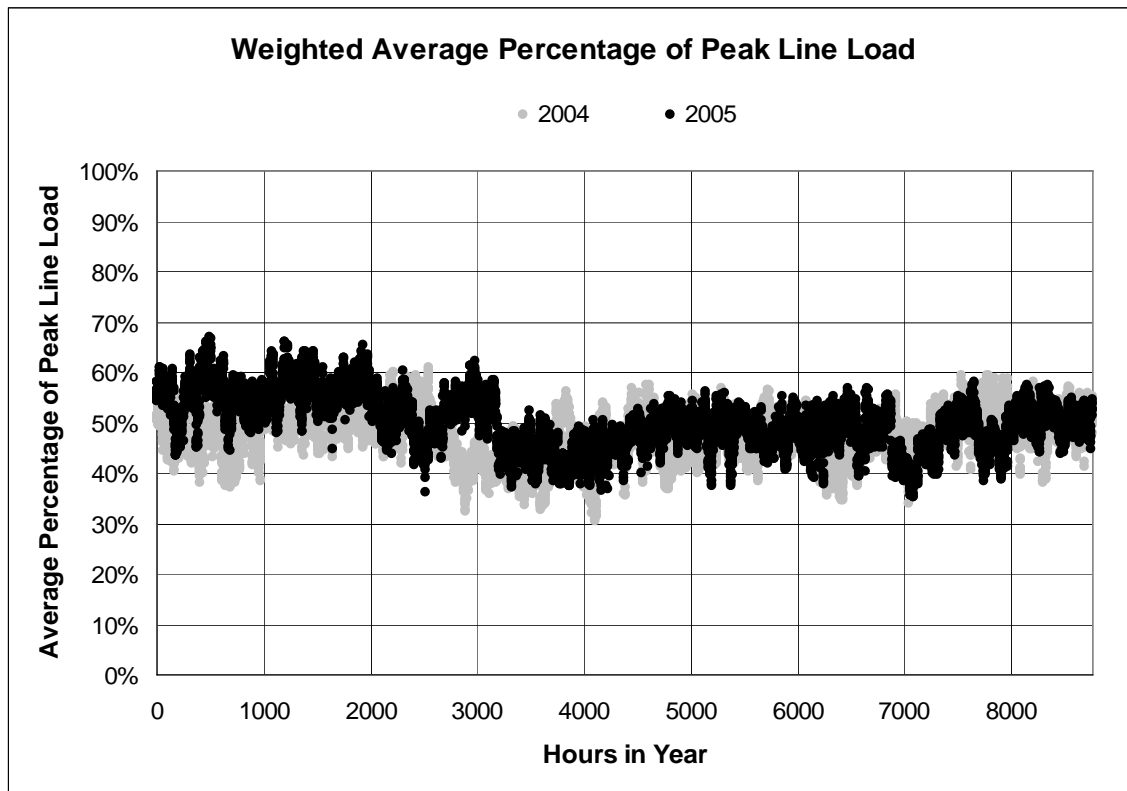
Reference: Reference the AESO 2007 GTA Section 4, page 37.

Request:

Please provide a chart using the data for Figure 4.6.1 with the load data presented in chronological order rather than as a load duration curve.

Response:

The requested chart is provided below, and is included with data in the attached Schedules ADC.AESO-031-A and -B.



Please note that Figure 4.6.1 presented the load duration curves for the weighted average of 240 kV lines from 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 average duration curves were calculated as the average of 79 individual duration curves for each 240 kV line. The average duration curve itself cannot be presented chronologically. To produce the chart above, the loading on each line was sorted chronologically and the weighted average was then calculated. This produces a different set of average data points than those presented in Figure 4.6.1.

The data used for the charge above was also posted on the AESO website shortly after the filing on December 13, 2006 of 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.

Request:

The AESO 2007 GTA Section 4, page 38 states that there is a forecast of 1,100 MW of backup load. What is the number of customers represented by the 1,100 MW of backup load? How many customers in Alberta have on-site generation?

Response:

The 1,100 MW of backup load in the Northeast Alberta Service Requirements included approximately 10 customers.

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. There may also be customers who have onsite generation but who have not contracted for generation service, either because their onsite generation does not meet all of their load needs (that is, they require supplemental service for their load as discussed in section 4.6 of the AESO's 2007 GTA) or for other reasons.

Reference: Reference the AESO 2007 GTA Section 4, page 35.

Request:

- (a) Please provide empirical evidence that customers with on-site generation would be likely to experience unscheduled outages at the same time.
- (b) Please provide empirical evidence that customers with on-site generation would be likely to experience unscheduled outages coincident with the time of the system peak.

Response:

- (a) The AESO has not based its proposed rates on an assumption that customers with onsite generation would be likely to experience unscheduled outages at the same time, and has not compiled empirical evidence in that respect.
- (b) The AESO's evidence is that recovering bulk system costs on a coincident system peak basis cannot be justified from a cost causation perspective. The AESO has not compiled empirical evidence that customers with on-site generation would be likely to experience unscheduled outages coincident with the time of the system peak.

Reference: Reference the AESO 2007 GTA Section 6, page 34

Request:

- (a) Under section 14.4, the AESO provides a sample calculation to assess the lump sum payment to a customer reducing their contract capacity. Please provide another sample calculation for the same customer under the current tariff. Please describe the differences in the results of the two calculations and reconcile to the actual costs of a customer reducing load or exiting the system.
- (b) Please indicate how many customers have exited the system in the past 5 years.
- (c) Of the customers that have exited the system in part b, how many were required to pay out the contract capacity? Please indicate the tariff in place at that time provide a calculation that compares the costs assessed against costs that would be assessed under revised section 14.4.
- (d) In Decision 2000-01, page 216, the Board recognized that under special circumstances, such as the absence of stranded costs or some other benefit to the system or remaining customers, may warrant a waiver of the notice provisions. For example, a given area of the province may have transmission constraints and EAL may be considering upgrading the transmission system. The Board directed that should EAL determine that circumstances warrant a waiver of notice its provisions, EAL should file a waiver with the Board and interested parties for comment.
 - (i) Has the AESO filed any such waivers?
 - (ii) What are the circumstances under which the AESO would file such a warrant?
 - (iii) Please list areas on the transmission system the AESO is considering upgrading where such a waiver would be filed.
 - (iv) Under what conditions would the AESO not consider filing a waiver?

Response:

- (a) All assumptions used in the buyout calculation are outlined below:

Notice Provided: 1-January-2006
 Reduction Effective: 1-January-2011
 Buy-down Effective: 1-July -2007

Tariff Applied: As per Decision 2005-096

Pre-Notice Capacity: 8.00 MW
 Post-Notice Capacity: 4.00 MW
 Reduction: 4.00 MW
 Metered Demand July 1, 2007: 4.00 MW
 Discount Rate: 7.92%

Coincidence with System Peak: 85%
 Load Factor: 70%
 No ratchet incurred prior to notification of termination

Assumed Billing Charges:

| | | |
|---------------------------|--|---------------|
| Bulk System charge | | |
| Coincident Metered Demand | | \$1,233.00/MW |
| Metered Energy | | \$1.41/MWh |
| Local System Charge | | |
| Billing Capacity | | \$553.00/MW |
| Metered Energy | | \$0.26/MWh |

Buyout amount: approx. \$56,000

The variance between the \$141,000 buy down calculation outlined in Section 6.7, page 36 of the Application and the \$56,000 provided above is primarily due to the nature of the Bulk System Charge. In the proposed tariff the bulk system charges would be recovered through a billing capacity charge while under the currently approved tariff the bulk system charge is based upon the customer's actual usage in the hour of the system peak (i.e. the coincident demand). To illustrate, if the customer chose to simply to reduce their consumption to 4.0 MW and their contract capacity remained at 8.0 MW, the bulk system charge portion of the DTS rate would be based upon the coincident demand in that month, which in this case would be 4.0MW. Under the proposed tariff the customer would be required to pay based on the billing capacity (90% of 8.0MW = 7.2MW). The AESO submits this is reasonable as the transmission system is constructed to meet the customer's original 8.0 MW system access request.

- (b) There have been 3 Points of Delivery (POD) and 7 Points of Supply (POS) that have exited the system since 2002.

| POD / POS | Contract Termination Date | Additional Detail |
|-----------|---------------------------|-----------------------------------|
| POD | 5-31-2005 | |
| POD | 5-31-2006 | |
| POD | 6-30-2002 | |
| 4 POS | 9-30-2005 | Regulating unit base life expired |
| 3 POS | 01-01-2001 | Regulating unit base life expired |

- (c) None of the PODs or POSs were required to pay out their contract capacity as each customer opted not to buy down their 5 year notice period early.
- (d)
 - (i) No, the AESO has not filed for any such waivers at this point in time as the AESO has not encountered any circumstances that it considers warrant such action.
 - (ii-iv) The AESO notes that this provision is from 2000, and is not part of the 2006 approved tariff. The existing and proposed tariffs are designed to be appropriate for all customers, reflecting that all customers receive comparable system access service, regardless of their location. Notwithstanding, the AESO acknowledges the passage from Decision 2000-01, and that it suggests that the AESO may

review, on a case by case basis, whether the circumstances around a termination warrant the waiver of the 5 year notice period. The AESO understands the intent is that if there is clear evidence that, as a direct result of the termination of the customer's service, transmission costs to serve new loads would be deferred or avoided thereby benefiting all ratepayers, the AESO may file this information with the EUB. However, also of note is that even if evidence of reduced transmission costs exists, this does not guarantee the waiver would ultimately be granted. The AESO is of the view that providing waivers of this nature could be construed as differentiating the tariff on the basis of location.