

Preamble: EnCana requests a summary of the rate design principles employed and evaluated by the AESO in preparation of its proposed rate design for DTS Interconnection System charges.

Reference: Section 4.5.1 DTS Interconnection - System Charge and Rate Design Principles

Request:

Please explain in detail how the proposed rate design for the DTS System charge (Table 4.5.1) was evaluated against the following rate design criteria as well as the weight the AESO attached to each criteria in its evaluation:

- (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 intercustomer subsidies;
- (iv) Stability and predictability of rates and revenue; and
- (v) Practicality (simple, convenient, understandable, acceptable, billable)

Response:

Consistent with the findings of the EUB in Decision 2005-096 as summarized in section 4.2 of the Application, the AESO gave primary consideration to the first three rate design principles and secondary consideration to the last two rate design principles. The evaluation against the rate design principles was qualitative rather than numerical.

- (i) Recovery of the total revenue requirement would be satisfied by a rate designed in accordance with Table 4.5.1, since the functionalization and classification simply determine the percentage of the total revenue requirement to be recovered by each rate component.
- (ii) The AESO examined the cost causation basis underlying the functionalization and classification in Table 4.5.1, as discussed in detail in sections 4.3 and 4.5 of the Application. Cost causation and price signal considerations were reviewed with AESO planning and operations personnel, investigated by PS Technologies through the preparation of the *2006 Transmission Cost Causation Update*, discussed with stakeholders during the 2007 rates consultation process, assessed against methodologies discussed in relevant literature, and debated internally within the AESO regulatory group. The AESO concluded the functionalization and classification in Table 4.5.1 appropriately satisfied the second rate design principle.

- (iii) Consideration of fairness, objectivity, and equity was primarily assessed through examination of the rate design as discussed in detail in section 4.5 and, in particular, the discussion regarding the point of delivery charge in section 4.5.2 of the Application. Fairness, objectivity, and equity were also pertinent to the backup or standby service analysis in section 4.6 of the Application. Fairness, objectivity, and equity considerations were also reviewed with AESO planning and operations personnel, discussed with stakeholders during the 2007 rates consultation process, examined in the context of relevant literature, and debated internally within the AESO regulatory group. The AESO concluded the functionalization and classification in Table 4.5.1 appropriately satisfied the third rate design principle.

Having concluded that the proposed functionalization and classification satisfied the three primary rate design principles, the AESO developed the DTS rate based on that functionalization and classification and then assessed the proposed rate against the two secondary rate design principles.

- (iv) Stability and predictability of the final rate design were assessed through bill impact analysis as discussed in detail in section 4.5.3 of the Application. The AESO reviewed the impact, by billing capacity and load factor and by rate component and in total, of the proposed rate design compared to both 2005 and 2006 DTS rates. Results were discussed with stakeholders during the 2007 rates consultation process and debated internally within the AESO regulatory group. The proposed rate design generally satisfied considerations of stability and predictability, with the exception of some PODs which would experience unreasonably large bill increases. In consideration of stability, the AESO decided that a bill impact mitigation rider should be proposed to limit 2005-2007 bill increases to no more than 300%. In consideration of predictability, the AESO decided the rider should be proposed to continue to December 31, 2008. The AESO concluded the rate design based on the functionalization and classification in Table 4.5.1, together with the rate impact mitigation rider, appropriately satisfied the fourth rate design principle.
- (v) Practicality of the final rate design was assessed through discussion with AESO billing staff and internal debate within the AESO regulatory group. No specific concerns were identified, as the proposed rate design is based on billing determinants which already exist within the transmission billing system. The proposed bill impact mitigation rider can also be implemented within the billing system. The AESO concluded the rate design based on the functionalization and classification in Table 4.5.1 appropriately satisfied the fifth and final rate design principle.

The AESO notes that although the evaluation of the rate design is presented as an orderly and sequential process in the above summary, the rate design was developed over a considerable period of time through an iterative process. Most aspects were discussed concurrently and from a variety of perspectives, including possible rate design alternatives. The many discussions were generally not documented beyond the information presented during the AESO's 2007 rates consultation process.

Preamble: There are two different types of end-use customers that use transmission services; those that are directly connected and billed directly from the AESO and those that are connected at a distribution level and billed indirectly via a distribution tariff.

Reference: Section 4.5.1 DTS Interconnection – System Charge and Rate Design Principles

Request:

- (a) Please explain what portion of the AIES load (energy and peak) is composed of distribution utility end-users. Of this amount what portion is transmission-connected and distribution connected. Of the distribution connected customers, what portion has interval meters and what portion does not?
- (b) Would the AESO agree that a rate design with appropriate price signals that reflect costs and benefits (cost causation) should take into account how all end-users, including distribution-connected end-use customers, obtain a price signal that will reflect on the manner such customers cause transmission costs and will result in the appropriate incentive to alter their consumption so as to reduce future transmission costs? Explain.
- (c) Would the AESO agree that if the DTS rates charged to Distribution utilities are not passed to distribution-connected end-users in a manner that reflects transmission cost causation, such end-use customers could cause higher transmission costs than otherwise? Explain.
- (d) Please explain in detail how the proposed rate design for DTS System Charges reflects the transmission costs that are caused by distribution-connected end-use customers and how the rate design promotes the ability of distribution utilities to in turn set rates that provides appropriate price signals for transmission costs.

Response:

(a)

Energy		Peak	
Distribution Utility End-User		Distribution Utility End-User	
96.9%		97.3%	
Distribution Connected	Transmission Connected	Distribution Connected	Transmission Connected
79.7%	20.3%	83.3%	16.7%

The AESO does not have the processes or data to provide distribution utility type of meter information to calculate the portion of distribution connected customer interval meters.

- (b-d) The AESO considers that its rates should provide price signals that reflect costs and benefits attributable to users of the transmission system. In the context of this discussion, the users of the transmission system are the distribution utilities. Based on these price signals, the distribution utilities will make decisions as to how to best manage their costs of transmission service, including setting rates for their customers that give consideration to what signals their customers can respond to in order to contribute to minimizing transmission costs.

Preamble: There are two different types of end-use customers that use transmission services; those that are directly connected and billed directly from the AESO and those that are connected at a distribution level and billed indirectly via a distribution tariff.

Reference: Section 4.5.1 DTS Interconnection – System Charge and Rate Design Principles

Request:

Discuss the “pros” and “cons” of the following rate mechanisms for recovering the demand-related portion of the transmission system charge from distribution-connected end-use customers via rates charged by Distribution utilities. Include a discussion of how each approach complies with the rate design principles listed in EnCana-AESO-1, with attention to cost causation.

- (a) 12 CP allocation method (one-hour per month) per POD
- (b) Multiple CP allocation (e.g. top 10 CP hours per month) per POD
- (c) Time specific allocation method (e.g. average of on-peak demand) per POD
- (d) Average of all hours demand per POD
- (e) Billing Capacity per POD

Response:

Please refer to the response to Information Request BR.AESO-002 (a).

Preamble: The 10-Year Transmission System Plan (2017-2016) will be filed with the Board on or before December 31, 2006.

Reference: Section 4.5.1 DTS Interconnection – System Charge and the 10-Year Plan

Request:

- (a) Please file a copy of the 10-Year Plan here.
- (b) Please provide in table format a list of each of the bulk system upgrades proposed under the 10-Year Plan. For each upgrade indicate the cut-plane or the planning area where it is required and the expected upgrade costs. Also provide a brief summary as to why the upgrade is necessary and explain the key drivers for the upgrade (i.e. the assumptions for the worst-case conditions). When the upgrade is triggered by the requirement to reliably meet future load, please explain whether the load that is to be served reliably reflects load at the time of system coincident peak, regional peak demand, the sum of customer peak or some other load assumption.

Response:

- (a) Please see Attachment EnCana.AESO-004, *10-Year Transmission System Plan 2007 – 2016*, dated December 2006.
- (b) The information requested is provided in Section 4, pages 37-55, of the Attachment. Beginning at page 44 the Plan describes eight different operating conditions (load level and generation dispatch) scenarios that were studied for each of the eleven generation development scenarios. The subsequent discussion for each of the four cut planes identifies the particular combination of operating conditions and generation scenario that resulted in the maximum loading stress on the particular cut plane. Tables 13, 14 and 15 of the Plan summarize the estimated cost and in-service date for each of the system reinforcements identified. Detailed analysis of the drivers for each reinforcement identified will be provided during the course of discussions with stakeholders through the planning process and will be included in the subsequent Need Application(s) filed with the Board.

Preamble: The 10-Year Transmission System Plan (2017-2016) will be filed with the Board on or before December 31, 2006.

Reference: Section 4.5.1 DTS Interconnection – System Charge and the 10-Year Plan

Request:

- (a) Do the AESO planning technicians in preparing the 10-Year Plan examine or take into consideration the customer specific peak load for either transmission-connected or distribution-connected end-use customers? If yes, explain in detail how this information is incorporated in the transmission planning and plans.
- (b) Please confirm that the load forecast used as an input to the 10-Year Plan is based on the same methodology as described in Appendix B (Demand and Energy Requirements Methodology) with the forecast extending out 10 years. In other words, the 10-Year Plan studies use a 'typical' load shape based on observed historical metering point loads aggregated to create a unique 'typical' AIES load shape, which is then escalated based on the projected energy growth. (Please discuss the weather normalization adjustment to the load forecast.)
- (c) In the next ten years, if the diversity in system load is reduced over time such that the system peak approaches the sum of customer-specific peaks, will the transmission system require more or less expansions than proposed under the 10-Year Plan. Explain why?

Response:

- (a) No. Please refer to the response to DUC.AESO-001 (d) for more information regarding system conditions that were considered in preparing the 10-Year Plan.
- (b) Confirmed. The AESO does not include a weather normalization adjustment in its load forecast methodology.
- (c) A reduction in diversity as indicated would result in an increase in the AIES system peak coincident loading. The impact on the transmission system would be dependent upon the generation development scenario that would develop to meet the load requirements within this time period as well as other relevant planning considerations.

Preamble: The 10-Year Transmission System Plan (2017-2016) will be filed with the Board on or before December 31, 2006.

Reference: Section 4.5.1 DTS Interconnection – System Charge and the 10-Year Plan

Request:

- (a) Did the AESO take into account any of the line loading data for 2004 and 2005 as presented in Appendix D when preparing the 10-Year Plan? Explain.
- (b) Please explain in detail the relevance of the line loading data as presented in Appendix D to the transmission planning practices used by the AESO. Please list which planning studies and Need applications, if any, relied on similar data to justify a transmission expansion and describe the nature in which such data was used.

Response:

- (a) In preparing the 10-Year Plan the applicable forecast load and generation scenarios were used in the analysis. The AESO did not specifically take into account the loading data as presented in appendix D when preparing the 10-Year Plan.
- (b) The AESO assesses the transmission requirements based upon the applicable forecast load and generation dispatch scenarios. The AESO has not specifically used the loading data as presented in Appendix D in the planning studies or Need Applications.

Preamble: Section 6.2 of the AESO *Transmission Reliability Criteria* states:

6.2 System Load

The [Alberta Transmission System] will be designed to supply forecast peak load and peak flows based on a forecast of MWh/hour in a normal weather year.

There are elements or paths of the system that may need to be designed to accommodate peak loads that are substantially higher when measured over shorter durations.

The loads to be used for specific geographic areas are the expected forecast coincident peak loads for load areas.

The loads to be used for generation surplus areas may be the light or peak loads. The system shall be planned for the most onerous reasonable load and generation conditions.

The system will be planned to accommodate long term firm contracts for interchanges to other jurisdictions.

Operational loads will be based on one-minute values unless otherwise stated.

Reference: Section 4.5.1 DTS Interconnection – System Charge and the AESO *Transmission Reliability Criteria*

Request:

- (a) Please file a copy of the *AESO Transmission Reliability Criteria (Version 0)* March 11, 2005.
- (b) Please confirm that the AESO continues to plan the Alberta Transmission System in accordance with the *Transmission Reliability Criteria*. If not, explain.
- (c) Please confirm that the AESO plans the transmission system to ensure that future system peak load (i.e. Alberta Internal Load) can be served reliably. If not, explain.
- (d) Please provide a summary of the timing of peak loads for each planning area used by the AESO and the coincidence of these area peaks relative to system peak. (Please submit all background data in a spreadsheet format.)
- (e) Would the AESO agree that when transmission upgrades are required to facilitate energy flows from an area that is generation surplus, load is not the trigger for such expansion costs? Explain.

- (f) Assume a transmission path is stressed in conditions of (a) energy flows from an area that is generation surplus and (b) light system load. Would the AESO agree that reducing load in this instance would not reduce or avoid the need for a system upgrade? Explain.

Response:

- (a) The *AESO Transmission Reliability Criteria* is attached.
- (b) Confirmed.
- (c) The AESO plans the transmission system to accommodate all relevant loading conditions. For example, please refer to the response to Information Request PWX.AESO-018.
- (d) Please see attached Schedule EnCana.AESO-007 (d).
- (e) The trigger would be dependent upon the applicable forecast system or local load and generation dispatch scenario.
- (f) Not necessarily. The local loading condition in the area may be driving the need for the system upgrade.

Preamble: In the 2006 GTA, AESO provided the following response under EnCana-AESO-14(a)

A cost of service or cost causation study on its own does not cause harm or detriment to anyone. Such a study is a technical and objective analysis of **how costs are caused**, accompanied by an allocation of these costs to rate classes.

The next step in the process is rate design, where one of the primary inputs, but not the only input, is usually a cost of service or cost causation study. The actual result of the rate design can impact all customers including both high load factor and low load factor customers. The goal of the process is to study costs, **to understand the nature of cost causation**, and to have rates that appropriately reflect costs and other rate design criteria. (emphasis added)

Reference: Section 4.5.1 DTS Interconnection – System Charge and Rate Design methodology.

Request:

Please summarize here the AESO's current evidence respecting how “costs are caused” as it relates to the transmission system costs (excluding POD costs).

Response:

The AESO evidence respecting transmission system cost causation is provided in section 4.3 of the AESO's 2007 GTA.

Preamble: In the 2006 GTA, AESO provided the following response under EnCana-AESO-14(a)

A cost of service or cost causation study on its own does not cause harm or detriment to anyone. Such a study is a technical and objective analysis of **how costs are caused**, accompanied by an allocation of these costs to rate classes.

The next step in the process is rate design, where one of the primary inputs, but not the only input, is usually a cost of service or cost causation study. The actual result of the rate design can impact all customers including both high load factor and low load factor customers. The goal of the process is to study costs, **to understand the nature of cost causation**, and to have rates that appropriately reflect costs and other rate design criteria. (emphasis added)

Reference: Section 4.5.1 DTS Interconnection – System Charge and Rate Design methodology.

Request:

- (a) When examining the nature of cost causation for purposes of developing rates should the cost causation study use a “backward looking approach” or a “forward looking approach”? A “backward-looking approach” would examine the triggers to past incurred costs. A “forward-looking approach” would examine the triggers to future planned costs.
- (b) Which approach has the AESO used in the 2007 GTA application? Please elaborate.

Response:

- (a-b) Please refer to the response to Information Request ADC.AESO-3 (c).

Preamble: In the 2006 GTA, AESO provided the following response under EnCana-AESO-14(a)

A cost of service or cost causation study on its own does not cause harm or detriment to anyone. Such a study is a technical and objective analysis of **how costs are caused**, accompanied by an allocation of these costs to rate classes.

The next step in the process is rate design, where one of the primary inputs, but not the only input, is usually a cost of service or cost causation study. The actual result of the rate design can impact all customers including both high load factor and low load factor customers. The goal of the process is to study costs, **to understand the nature of cost causation**, and to have rates that appropriately reflect costs and other rate design criteria. (emphasis added)

Reference: Section 4.5.1 DTS Interconnection – System Charge and Rate Design methodology.

Request:

Please summarize here why and how the final proposed rate design for the system charges (**Table 4.5.1**) reflects the nature of cost causation on the transmission system.

Response:

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

Preamble: The Application says:

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.** (Emphasis added)

Reference: Section 4.5.1 (p.16 of 53)

Request:

- (a) Would the AESO agree that recovering some portion of the demand-related costs on the basis of peak load responsibility (e.g. 12CP or average On-peak demand) can account for the varying POD load factors and the coincidence of end-use loads with maximum stress on the transmission system (especially when such stress is triggered by peak system load)? Explain.
- (b) Would the AESO agree that the Board's approved classification and recovery of transmission costs in Decision 2005-096 reasonably accounts for load diversity by including the recovery of bulk system costs using 12 CP, NCP and Energy as summarized here:

**Functionalization and Classified Transmission Wire Costs
EUB Order U2005-464 (2006 Tariff)**

	Total	% of Total				% of Function			
		12CP	NCP	Usage	Customer	12CP	NCP	Usage	Customer
Bulk System	41.0%	24.1%	-	16.9%	-	58.8%	-	41.2%	-
Local System	17.1%	-	14.0%	3.1%	-	-	81.9%	18.1%	-
System	58.1%	24.1%	14.0%	20.0%	-	41.5%	24.1%	34.4%	-
POD	41.9%	-	17.9%	-	24.0%	-	42.7%	-	57.3%
Total	100.0%	24.1%	31.9%	20.0%	24.0%				

- (c) Would the AESO agree that the Board's approved classification and recovery of transmission costs in Decision 2005-096 reasonably addresses the competing issues raised in this application – load diversity, causation of (non-standby) low load-factor customers, causation of standby customers, some recognition of peak load responsibility, some recognition of cost responsibility in all hours, single system charge for all AESO customers? If not, explain why.

Response:

- (a) The AESO does not agree. Recovering demand-related costs on the basis of system peak coincidence assumes that bulk transmission system components experience

maximum stress at the time of system peak, which is not supported by the analysis completed for the AESO's 2007 GTA. Please refer to the responses to Information Requests IPCAA.AESO-014 and IPCAA.AESO-015 for additional information.

- (b-c) The AESO does not agree. Although the EUB's decision was reasonable based on the analysis and discussion available during the AESO's 2006 GTA, significant additional analysis of transmission system cost causation and cost recovery has been completed for the AESO's 2007 GTA. The recovery of bulk transmission system costs on the basis of coincidence with system peak is not supported by the additional analysis. As well, the additional analysis supports a greater proportion of cost recovery on a usage-related (\$/MWh) basis. Please refer to the responses to Information Requests BR.AESO-002 (b) and IPCAA.AESO-026 for additional information.

Preamble: The Application states:

Allocating and recovering the majority of transmission system costs on a non-coincident peak basis may be most appropriate when customers have reasonably similar load factors. This is not the case for the transmission system, where 230 DTS PODs have load factors of 60% or more, 138 PODs have load factors between 40% and 60%, and 117 PODs have load factors below 40%.

The “average and excess” method suggested by some stakeholders generally provides better recognition of variations in load factor, since it accounts for the increasing likelihood of an individual customer’s contribution to a peak system component demand with increasing load factor. This method also does not distinguish between customers based on timing of the customer’s load, which seems to appropriately reflect the AESO’s findings in its analysis of the transmission system. (Emphasis added)

Reference: Section 4.5.1 (p.16 of 53)

Request:

- (a) Please confirm that during the stakeholder consultation process (as profiled in Section 3 of the Application) the AESO did not present any rate design proposals based on the “average and excess” (A&E) method nor did it present the A&E method as an alternative rate design method for the bulk system charges.
- (b) Please provide the theoretical grounding behind the A&E method and discuss why such a method should be used to adjust the portion of demand-related costs.

Response:

- (a) Please refer to the response to Information Request IPCAA.AESO-003 (a-b).
- (b) The following discussion of the average and excess demand (AED) approach is taken from *Principles of Public Utility Rates* by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen (Public Utilities Reports, Inc., Arlington, Virginia, 2nd Edition, 1988, pp 497-498):

Average and Excess Demand Formula. *The third formula is called the “average and excess demand” (AED) method by Caywood (1972), who points out that it reaches the same result, though by a different mathematical technique, as that reached by another method called the “Greene method.” Here, the assumed cost of that portion of the company’s plant capacity which would be needed even if all consumers were taking their power at 100 per cent load factor is apportioned among consumers in proportion to their average loads — that is, in proportion to their kilowatt-hour consumption of energy during the time period in*

question. But the assumed cost of the excess in actual plant capacity over this lower, hypothetical capacity is apportioned by applying the noncoincidental peak method to the difference between maximum loads and average loads.

Like other formulae which, overtly or in effect apportion a part of the capacity costs among kilowatt-hours of energy rather than entirely among kilowatts or kilovolt amperes, the average and excess demand method has a certain degree of justifiable support from the standpoint of cost analysis. This support lies in the fact that, when the extent of coincidence between the maximum load of any given ratepayer and the peak system load cannot be measured or prophesied directly, one may be justified in assuming 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. Thus, the maximum load of a 100 per cent load-factor ratepayer is certain to coincide at some point of time with system peak, whereas the maximum load (or, for that matter, even the entire load) of a 10 per cent load-factor ratepayer may be entirely off the system peak. However, no one stochastic or probabilistic method of capacity-cost imputation has received widespread acclaim. Instead, empirical studies of the relationship between load factors and coincidence factors for different uses of service (air conditioning, water heating, elevator operation, etc.) are required.

There have been several variants of the average and excess demand method used in various jurisdictions including assigning the average demand portion by both load and diversity factors; employing peak and base methods; and using noncoincident demands (Catalano, 1981). If the agency believes that the capacity costs should reflect load diversity or generation mix, there is some merit in the average and excess demand method. That is, regulators sometimes feel it is fair to allocate on an energy basis a large portion of demand charges because utilities are building new generation plants to save on fuel costs rather than to meet peak distortions. They favor allocating energy costs on a marginal cost basis, such as the peaker method — which does it on short-run marginal costs — and allocating demand costs on the cost of a peaking unit which is less costly than a new base-load unit. (emphasis in original)

Additional discussion of the average and excess demand approach can be found in *The Process of Ratemaking* by Leonard Saul Goodman (Public Utilities Reports, Inc., Vienna, Virginia, 1998, p 1069) and in the *Electric Utility Cost Allocation Manual* by the National Association of Regulatory Utility Commissioners (Washington, D.C., January 1992, pp 49-52 and 81-82).

As discussed in the second paragraph of the above extract from Bonbright et al., the average and excess demand approach reflects the probability of coincidence between the maximum load of a customer and the peak loading on the system. Since the various components of the transmission system experience peak loading at different times, it is not practical to measure or predict when a customer's maximum load would coincide with the various transmission component peak loads. It is therefore appropriate to use the probabilistic method inherent in the average and excess demand approach and to allocate on an energy basis costs which are classified as demand-related.

Reference: Section 4.5.1 DTS Interconnection – System Charge

Request:

- (a) Please discuss the expected consumption behaviour of transmission-connected and distribution-connected end-use customers as a result of collecting the system charges using Billing Capacity (as proposed by the AESO) to recover system charges. Please give consideration to both low and high-load factor customers.
- (b) Please discuss the expected consumption behaviour of transmission-connected and distribution-connected end-use customers if system charges were recovered using a price mechanism reflecting peak-load responsibility (e.g. 12CP, or average on-peak demand). Please give consideration to both low and high-load factor customers.

Response:

- (a-b) As discussed in the response to Information Request IPCAA.AESO-028, the AESO considers that the billing capacity component of the proposed system charge provides a clear signal that customers should avoid demand peaks and should strive for as flat a load provide as possible. That signal applies to both low load factor and high load factor customers. It is likely that a low load factor customer will not be able to respond to the price signal and achieve a flat load profile, in which case the proposed system charge appropriately recovers costs from such a customer.

If the system costs were recovered based on coincidence with system peak, the system charge would provide a price signal that customers should minimize their loads at times when system peaks were likely to be set. Customers would receive no signal regarding use of system facilities at other times, despite it being 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 price signal would apply to both low load factor and high load factor customers. However, low load factor customers could potentially more readily avoid the times of system peak and avoid system charges, despite contributing to system loading conditions at other times.

Please refer to the response to Information Request ADC.AESO-007 (a-b) for additional information.

The distribution utility is responsible for allocating transmission system charges to distribution-connected end-use customers. Please refer to the response to Information Request EnCana.AESO-002 (b-d) for additional information.

Preamble: For a single month comparison EnCana calculates the proposed DTS System Charges as follows:

Monthly System Charge per AESO Proposal

Billing Capacity \$1,176/MW
Metered Energy \$2.42/MWh

Assumptions 10 MW Contract Capacity
 9 MW Monthly Peak & Billing Capacity

LF	Billing Capacity (MW)	Monthly Energy (MWh)	Demand Charge (\$)	Energy Charge (\$)	Total System Charge per Month (\$)
10%	9	648	10,584	1,568	12,152
20%	9	1,296	10,584	3,136	13,720
30%	9	1,944	10,584	4,704	15,288
40%	9	2,592	10,584	6,273	16,857
50%	9	3,240	10,584	7,841	18,425
60%	9	3,888	10,584	9,409	19,993
70%	9	4,536	10,584	10,977	21,561
80%	9	5,184	10,584	12,545	23,129
90%	9	5,832	10,584	14,113	24,697
100%	9	6,480	10,584	15,682	26,266

Reference: Section 4.5.1 DTS Interconnection – System Charge

Request:

- (a) Please confirm the calculation correctly reflects the AESO's proposal. Please adjust for any inaccuracies.
- (b) Please explain why a demand-charge that is constant across the range of load-factors is a proper reflection of transmission cost causation.
- (c) Please explain why a 10% load-factor customer causes as much as 46% of the transmission system costs as a 100% load-factor customer ($\$12,152/\$26,266 = 46.3\%$).

Response:

- (a) Confirmed.

- (b) The proposed non-coincident peak demand (\$/MW) component of the system charge reflects the importance of demand in every hour. The associated usage (\$/MWh) component of the system charge appropriately accounts for variations in load factor between customers. Please refer to the response to Information Request ADC.AESO-009 (a-b) for additional information.
- (c) Please refer to the responses to Information Requests IPCAA.AESO-015 and IPCAA.AESO-022.



Preamble: Assume that Customer A and B have consumptions profiles as illustrated in the following calculation of the AESO's proposed system charge

System Charge per AESO Proposal
Billing Capacity \$1,176/MW Metered Energy \$2.42/MWh

Customer A

Month	LF	Contract Capacity (MW)	Monthly Peak (MW)	Billing Capacity (MW)	Monthly Energy (MWh)	Demand Charge (\$)	Energy Charge (\$)	Total System Charge (\$)
1	0%	10	0	9	0	10,584	0	10,584
2	0%	10	0	9	0	10,584	0	10,584
3	15%	10	10	10	1,080	11,760	2,614	14,374
4	0%	10	0	9	0	10,584	0	10,584
5	0%	10	0	9	0	10,584	0	10,584
6	0%	10	0	9	0	10,584	0	10,584
7	0%	10	0	9	0	10,584	0	10,584
8	0%	10	0	9	0	10,584	0	10,584
9	0%	10	0	9	0	10,584	0	10,584
10	0%	10	0	9	0	10,584	0	10,584
11	0%	10	0	9	0	10,584	0	10,584
12	0%	10	0	9	0	10,584	0	10,584
Total	1%				1,080	\$ 128,184	\$ 2,614	\$ 130,798

Customer B

Month	LF	Contract Capacity (MW)	Monthly Peak (MW)	Billing Capacity (MW)	Monthly Energy (MWh)	Demand Charge (\$)	Energy Charge (\$)	Total System Charge (\$)
1	95%	10	9	9	6,156	10,584	14,898	25,482
2	95%	10	9	9	6,156	10,584	14,898	25,482
3	95%	10	10	10	6,840	11,760	16,553	28,313
4	95%	10	9	9	6,156	10,584	14,898	25,482
5	95%	10	9	9	6,156	10,584	14,898	25,482
6	95%	10	9	9	6,156	10,584	14,898	25,482
7	95%	10	9	9	6,156	10,584	14,898	25,482
8	95%	10	9	9	6,156	10,584	14,898	25,482
9	95%	10	9	9	6,156	10,584	14,898	25,482
10	95%	10	9	9	6,156	10,584	14,898	25,482
11	95%	10	9	9	6,156	10,584	14,898	25,482
12	95%	10	9	9	6,156	10,584	14,898	25,482
Total	85%				74,556	\$ 128,184	\$ 180,426	\$ 308,610

Reference: Section 4.5.1 DTS Interconnection – System Charge

Request:

Please confirm the calculation correctly reflects the AESO's proposal. If not please provide a correct summary of the system charges for customer A and B.

The AESO's proposed rate for system charges appears to imply that Customer A has an equal contribution or causation to system demand-related costs. Please explain how a customer that has a 1% annual load-factor (Customer A) causes the same demand-related transmission system costs as a customer with an annual load-factor of 85% (Customer B).

Response:

Confirmed.

In assessing the impact of the proposed system charge, it is inappropriate to consider just the demand component of the charge on its own. As EnCana observed, the same demand charges are assessed to customers of the same capacity but with significantly different load factors. This effect, together with other matters discussed in section 4.3.2 and 4.5.1, led the AESO to allocate a significant portion of demand-classified system costs on a usage (\$/MWh) basis. The resulting usage component must be included in an examination of system charges.

When both the demand and usage components of the system charge are considered together, Customer A (with 1% load factor) pays about 58% less in system charges than Customer B (with 95% load factor). Based on the AESO's analysis, this reduction reflects an appropriate allocation of system costs to each customer.

Preamble: At pages 35-36, the application attempts to assess the costs attributable to backup loads using the weighted average duration curve for loading on the 240 kV lines for 2004 and 2005. On page 36, the application makes the following assumption:

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. (Emphasis Added)

Reference: Section 4.6.2 Backup Service Costs

Request:

- (a) The AESO appears to have confused the concept of “load duration” with “load coincidence”. What data does the AESO have to support the assumption that each 5% load factor customer (whether or not a back-up load) would be using the transmission system **at times coincident** with the top 5% of line loadings?
- (b) Is it reasonable to alternatively assume that a 5% load-factor customer (whether or not a back-up load) could be using the transmission system coincident with those times when the line loading is at 50% or 25% or 5% of maximum observed line load? Explain.
- (c) If the AESO agrees with this observation, does the AESO agree that the method used on p.35 (li. 43) to p.37 (li.7) of Section 4 to estimate the cost contribution of low load-factor customers (in general) is faulty? Explain.
- (d) Does the AESO agree that if a 5% load factor customer does not use the transmission system coincident with the times of system peak then these customers will have no, or only a small, impact on the need to expand the transmission system? Explain.

Response:

- (a) Please refer to the responses to Information Requests IPCAA.AESO-045 (a-b) and IPCAA.AESO-046 (b).
- (b) Please refer to the response to Information Request ADC.AESO-027.
- (c) The AESO considers that the load-duration profile analysis is a reasonable approach to estimate the impact of short-duration loads on the transmission system. Given the relatively flat average loading of most 240 kV transmission lines as illustrated in Figure 4.3.5 (on page 10 of section 4 of the AESO’s 2007 GTA), the portion of the load-duration

curve to the left of the 5% duration threshold in Figure 4.6.1 (on page 36 of section 4) is likely to include many loads of less than 5% duration.

- (d) 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 further finds that load on the transmission system in every hour is important, and it is likely that the peak load of a low load factor load will coincide with maximum load on some transmission system components.

Please refer to the responses to Information Requests IPCAA.AESO-015 and IPCAA.AESO-022 for additional information.

Preamble: Page 14 of the draft Section 4 document circulated to stakeholders as part of the consultation process says:

In general, the AESO found that short-duration, infrequent use does not give rise to long-term or short-term costs on the transmission system. Discussions with AESO system planning and operations planning suggest 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. This conclusion assumes a small number of such loads in any specific planning area, and reasonable diversity of the timing of such loads in an area. However, particular concern was expressed about the Fort McMurray area where a number of loads would be expected to request standby or backup service, and where the assumed diversity may not exist.

Reference: Draft Section 4 – 2007 Rate Design (July 21, 2006)

Request:

- (a) Please confirm the finding that generally short-duration infrequent use (low load factor customers) does not give rise to transmission costs.
- (b) Would the AESO agree that ‘partial requirements’ customers are a unique class of low-load factor and intermittent user of the grid that causes system costs? If no, explain what other type of low load factor customer causes system costs and the extent of these costs?
- (c) Please explain why the proposed DTS rate, which appears to be designed to allocate costs to low load factor customers as if all such customers were “partial requirement” customers causing costs, will not harm the low load factor customers that in fact do not and have not caused transmission costs?

Response:

- (a) Not confirmed. Upon further investigation and analysis as discussed in section 4.6.2 of the AESO’s 2007 GTA, the AESO has assessed transmission system costs attributable to backup loads.
- (b) As discussed on page 32 of section 4 of the AESO’s 2007 GTA, not all partial requirements customers are low load factor, intermittent users of the transmission grid. Supplemental service customers regularly take transmission service for load in excess of their onsite generation capacity, and economic replacement service customers may take transmission service for extended periods depending on the cost of producing and delivering electricity relative to the cost of their onsite generation.

With respect to backup or standby service, the AESO provided the following comments at lines 37-40 on page 34 of section 4 of its 2007 GTA:

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.

The AESO's analysis does not distinguish between types of low load factor customers, but considers that costs should be allocated in a similar manner to all low load factor customers.

- (c) Please refer to part (a) above and the response to Information Request EnCana.AESO-016 (d).

Preamble: EnCana wishes to know how the proposed DTS rate will provide an appropriate price signal to control load so as to reduce future demand-related costs.

Reference: Section 4.5.1 DTS Interconnection – System Costs

Request:

- (a) If the Board approves the use of Billing Capacity to recover System Charges as proposed by the AESO in Section 4.5.1, please explain how the AESO will set each AESO customer's Billing Capacity in the initial month of implementation. (i.e. for each POD)
- (b) In respect of the demand-related System charges as proposed by the AESO, would the AESO agree that once a POD customer sets a ratchet in their Billing Capacity the incentive to control load is reduced considerably in all hours. Please explain, providing numerical and graphical examples.
- (c) In respect of the demand-related System charges as proposed by the AESO, would the AESO agree that once a ratchet is set there is little to no savings for high load factor customers to reduce their POD load below their contract capacity in any hour or any incentive for low load-factor customers not to raise the POD load up to their contract capacity in any hour? Please explain, providing numerical and graphical examples.

Response:

- (a) Billing Capacity already exists in the AESO billing system for calculation of local system and point of delivery charges under the AESO's 2006 DTS rate. The existing values will simply also be used to bill system charges under the proposed DTS rate.
- (b) The AESO disagrees. If a peak load establishes a ratchet level which determines billing capacity in future months, demands in those future months could also establish a subsequent ratchet level which would apply after expiry of the initial ratchet. The customer therefore continues to receive an incentive to control load, avoid demand peaks, and strive for as flat a load profile as practical, as discussed in the response to Information Request IPCAA.AESO-028.
- (c) A high load factor service would exhibit a reasonably flat load profile, which is the profile encouraged by the AESO's proposed system charge as discussed in the response to Information Request IPCAA.AESO-028. There would generally be little opportunity for such a customer to further reduce charges under any billing methodology, since approximately the same load would be "on the system" all the time. As well, high load factor customers generally experience minimal ratchet effects since their loads vary within a narrow range.

The request further asks about effects of reducing load below and raising load up to contract capacity. In general there should be minimal reduction in demand (\$/MW) charges if a customer operates below contract capacity. The transmission system is built, operated, and maintained in part in expectation of a customer utilizing the transmission system at the contracted level. Loads below contract do not materially reduce these costs.

Although there would be no reduction in the demand (\$/MW) component of the proposed system charge if a high load factor customer did reduce load below contract capacity, there would be a reduction in the usage (\$/MWh) component of the charge reflecting the customer's lower usage in the billing period.

Similarly, although there would be no increase in the demand component if a low load factor customer did increase load up to contract capacity, there would be an increase in the usage component reflecting the customer's higher usage in the billing period.

Preamble: The Application states:

The AESO therefore considers that recent usage of the bulk system is an appropriate basis for cost classification for rate design. (p.11 of 53)

Reference: Section 4.3.2 Bulk Transmission System Cost Classification

Request:

- (a) Please summarize here the AESO's line of reasoning and conclusions on what portions of the bulk system costs should be classified demand-related and energy-related based on the study of recent usage of the bulk system.
- (b) The original Transmission Cost Causation Study (TCCS) used the minimum system approach to classify the bulk system costs between demand-related and energy-related costs. It appears as though this method has been abandoned. Please explain whether the AESO continues to rely on the minimum system approach, how it does so and whether the minimum system approach was applied to all of the lines comprising the bulk system in order to determine the exact portion of costs that are energy-related.

Response:

- (a-b) The AESO considers the minimum system approach as applied in the original *Transmission Cost Causation Study* to provide an appropriate classification of the bulk system function as 81.5% demand-related and 18.5% usage-related, as summarized in Table 4.3.7 on page 14 of section 4 of the AESO's 2007 GTA. Details on the application of that approach were provided in the original *Study*.

Please refer to the response to Information Request IPCAA.AESO-008 (b) for additional information

Preamble: Page 3 of the TCCS Update says:

Maximum stress in the Bulk System is a situation where transmission planning criteria are in violation, and an upgrade is required to alleviate the violation. Stress results when there is violation of limits with respect to one or more of the following parameters:

- Thermal capacity,
- Voltage,
- Stability

And at page 13 it says:

This exercise must be simplified because maximum stress can occur for a number of different reasons. One way to simplify the issue for study is to simply consider loading on Bulk System components. While this may provide some insight, it does not fully reflect how the system is planned, because the system is planned with computer simulations that consider interaction between components.

Reference: Appendix C – TCCS Update

Request:

- (a) Would the author of the TCCS Update agree that the historical average of line loadings of 240kV circuits is not a reliable predictor of when or where on the bulk system network there will be a violation of the reliability criteria and the need for transmission system costs? If not, explain.
- (b) Would the author of the TCCS Update agree that the historical pattern of line loading on one individual circuit or on a group of circuits is not a reliable predictor of when or where on the bulk system network there will be a violation of the reliability criteria and the need for of transmission system costs? If not, explain.
- (c) If the author of the TCCS believes that historical line loading data can reliably predict system upgrade requirements, please demonstrate how the line loading data for 2004 and 2005 is a reliable predictor of the system upgrades the AESO has proposed in the 10-Year Plan.

Response:

- (a-c) The historical average of line loadings of 240 kV circuits is a view of actual usage of existing transmission facilities. Transmission planning for the future takes into account existing transmission facilities, load, and generation, and must also consider additions and deletions of generators and loads, and their specific location, in the future.

Therefore, by itself, existing line loading does not predict when or where future constraints may occur.

Preamble: Page 4 of the TCCS Update says:

The time of maximum stress on the Bulk System is **driven by a number of variables including 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.** The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta. The maximum demand at each POD is a more appropriate indicator of contribution to stress on the Bulk System. (Emphasis added)

Reference: Appendix C – TCCS Update

Request:

- (a) Given multiple reasons why stress (i.e. a violation of the reliability criteria) can occur why does the TCCS presume that peak system load should be the only predictor of all instances of stress?
- (b) Explain the line of reasoning used in the TCCS Update to conclude that “maximum demand at each POD is a more appropriate indicator of contribution to stress on the Bulk System”.
- (c) For each instance in which stress is triggered by generation, the configuration of the transmission system or reasons other than the need to reliably serve peak system load, provide a statistical summary demonstrating that maximum POD demand (i.e. Billing Capacity) can reliably predict such stress.

Response:

- (a) The *2006 Transmission Cost Causation Update* does not presume that peak system load, or the timing thereof, is the only indicator of maximum stress on the system. The *Update* shows that maximum stress can and does occur at times other than the time of ALL peak.
- (b) Maximum demand at a POD will contribute to high demands in the transmission system in close proximity to the POD. As one moves further back into the transmission system, high demands in the transmission system will occur when the combination of POD load in the area is high. The correlation between CP and maximum stress on the bulk system is generally weak, and negative in some cases. Therefore, NCP is assessed as a more appropriate indicator than CP of contribution to stress on the Bulk System.
- (c) It is not possible to complete the requested analysis because stress on bulk system components is caused by a number of factors and occurs at various times throughout the year. Existing load cannot be reliably used to predict when and where the Bulk

System may be stressed in the future. Please refer to the response to Information Request Encana.AESO-020 for additional information.

Preamble: Page 4 of the TCCS Update says:

The Bulk System **is planned to meet the demand for electricity throughout the year**, and the issue at stake is what demand parameter is the best basis to classify demand related costs. (Emphasis added)

Reference: Appendix C – TCCS Update

Request:

- (a) Is the TCCS Update proposing that the AESO uses a planning criteria that differs from the *AESO Transmission Reliability Criteria* (Version 0, March 11, 2005) If yes, please identify the planning criteria the TCCS assumes the AESO to be using.
- (b) Would the author of the TCCS Update agree that the AESO plans the transmission system according to the *AESO Transmission Reliability Criteria* (Version 0, March 11, 2005) so as to ensure that **forecast** peak load can be served reliably and that as a consequence transmission system costs are “driven” by expected peak loads and not average loads, either now or in the future. Please discuss.

Response:

- (a) No.
- (b) Please refer to EnCana.AESO-023 (a).

Preamble: Page 13 of the TCCS Update says:

In addition to the qualitative assessments in Section 2.2.2, quantitative analysis was undertaken to study the correlation between the time of maximum stress on the Bulk System and the time of ALL peak load. This exercise must be simplified because maximum stress can occur for a number of different reasons. One way to simplify the issue for study is to simply consider loading on Bulk System components. **While this may provide some insight, it does not fully reflect how the system is planned, because the system is planned with computer simulations that consider interaction between components.** This study was accomplished by obtaining meter data for 240 kV circuits that were in service during 2003, when the original cost data for the TCCS was obtained. For this analysis, the 240 kV circuits are assumed to represent the Bulk System. (Emphasis added)

Reference: Appendix C – TCCS Update

Request:

- (a) Would the author of the TCCS Update agree that if the transmission system is **planned** in accordance with the AESO's *Transmission Reliability Criteria (Version 0)* the **operation** of the transmission system on a real-time basis would normally not observe any conditions of stress (violations of the reliability criteria) because adequate capacity will always exist prior to the real time usage?
- (b) If not, explain why the line loading data of individual circuits reflect a *bona fide* stress of the transmission system (i.e. violation of the reliability criteria) and which of these observed "stresses" in the 2004 and 2005 data has caused the AESO to file a Need Application in order to expand or enhance the transmission system (i.e. to cause costs to be incurred.)

Response:

- (a) Yes, one would expect that the transmission system normally provides continuous service, even in the event of a contingency. However, the question does not appear to properly recognize the differences between the processes of planning and operating the transmission system. The planning of the transmission system includes provisions to ensure continuous service under specified conditions (for example, one contingency at the time of maximum stress on a system component). The operation of the system is quite different in that very seldom, if ever, do these precise "planning" conditions occur. In real time, several contingencies may occur (each with varying impact) at any time, regardless of the time of maximum stress or peak load. There are so many different scenarios and contingencies that occur in operating the system that planners cannot practically plan for all of them. Therefore, planning criteria are developed to simplify the planning of the electric system. The planning criteria are designed so that the

transmission system is expanded to be robust enough to accommodate most of the operating problems that occur in real time. However, adherence to planning criteria does not guarantee that there will always be adequate transmission to provide continuous service.

- (b) Line loading data by itself does not constitute a stress, which is generally defined as a violation of thermal capacity, voltage, or stability limits. The *2006 Transmission Cost Causation Update* has not been used to justify enhancements to the transmission system in the form of a need application or a long-term transmission development plan.

Preamble: Page 4 of the TCCS Update says:

Allocation of costs to the coincident peak has the potential to shift loads away from the coincident peak without any corresponding reduction in the causation of costs resulting in a volatile cost allocation.

Reference: Appendix C – TCCS Update

Request:

- (a) Does the author of the TCCS Update agree that the causes of transmission system expansions can be separated into two categories: (a) those caused by the need to reliably serve peak load, (b) those caused for other reasons? Explain.
- (b) When transmission costs are triggered by system peak load will a price signal based on an NCP (with ratchet) rate design induce load behaviour that will reduce peak load levels and the causation of costs? Explain.
- (c) When transmission costs are triggered by the expansion of generation additions (e.g. Southern Alberta) will a price signal based on an NCP (with ratchet) rate design induce load behaviour that will reduce the causation of costs? Explain.

Response:

- (a) The AESO interprets the question to be asking: “Are transmission system expansions required for one reason, or all other reasons?” and on that basis, the only possible answer is yes. The *2006 Transmission Cost Causation Update* does not identify these categories as rationale for transmission system upgrades. The *Update* identifies causes for transmission system expansions on the basis of violations of transmission planning criteria as identified in section 2 of the *Update*.
- (b) Generally, yes, when peak demands on a transmission system component are reduced, transmission expansions can be deferred. However, this is not always true. As identified in Section 2.2.2 of *2006 Transmission Cost Causation Update*, there are other factors that must also be taken into consideration. For example, the addition of generation may require expansion of the transmission system and this is unrelated to load. In this case, no price signal applicable to load can have an impact. The following is extracted from page 13 of the *Update* to illustrate this concept:

This qualitative assessment shows that transmission planning is very complex and is not dominated by any one simple factor such as ALL 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.

- (c) No. There is no relation between the addition of new generation and individual POD demand, and price signals applied to load will have no direct impact on the addition of new generation.

Preamble: Page 32 of 53 says:

Services for partial-requirements customers may be categorized into four types (adapted from *Rate Structures for Customers With Onsite Generation: Practice and Innovation*, National Renewable Energy Laboratory, December 2005, p. 6):

- (a) *Backup or standby service* serves a customer load that would otherwise be fully served by onsite generation during unscheduled outages of the onsite generation.
- (b) *Supplemental service* is for customers whose onsite generation does not meet all of their needs.
- (c) *Scheduled maintenance service* is taken when a customer's onsite generation is planned to be out of service for maintenance or repair.
- (d) *Economic replacement service* is offered at times when the cost of producing and delivering electricity are less than that of the onsite generation.

Reference: Section 4.6 Standby Service

Request:

- (a) Would the AESO agree that the characteristic which distinguishes "partial requirement" customers from other low load-factor users is that such customers have a native load (which is typically firm or non-interruptible) that is served primarily by on-site generation and secondarily by energy imported from the AIES grid. Are there any other characteristics?
- (b) For each type of "partial requirements" service identified by NREL explain what transmission costs are incurred in Alberta to provide the short-duration intermittent service.
- (c) What transmission costs are planned in the 10-Year Plan to service each type of short-duration intermittent consumption?

Response:

- (a) The description of "native load...that is served primarily by on-site generation" applies to the backup or standby service and the scheduled maintenance service categories. It does not necessarily apply to supplemental service, where service from the transmission grid is an ongoing and recurring requirement, nor to economic replacement service, where service from the transmission grid may be long-term depending on the cost of transmission service compared to onsite generation. The AESO suggests, as stated at lines 1-2 on page 32 of section 4 of its 2007 application, the defining characteristic of

“partial-requirements customers” is that they have onsite non-emergency generation. Whether they also have native load which is typically firm or non-interruptible, and whether such load is primarily served by the onsite generation, are common, but not necessarily defining, characteristics of partial-requirements customers.

- (b) The *10-Year Transmission System Plan 2007-2016* (provided in the response to Information Request EnCana.AESO-004) summarized the planning criteria of the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC). That summary included the following NERC/WECC comments on page 26:

“The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and maintenance equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

The transmission system is accordingly planned, built, and operated to account for “continuously varying customer demands” which include all of the different categories of partial-requirements services. The specific studies conducted for system planning utilize load forecasts based on past historical loading on the transmission system, which includes loads of partial-requirements customers. As a result, the provision of service to partial-requirements customers is embedded in the system projects throughout the province, and is generally not identified during project development and specifically not in the categories identified by NREL.

Specific costs cannot therefore be identified with the categories of partial-requirements customers. Costs must be allocated to such customers more generally. As explained by the AESO in section 4.6.2 of the Application, analysis suggests a megawatt of backup load should be allocated about 38% of the transmission system charges for a megawatt of normal load.

- (c) The only part of the *10-Year Plan* that specifically deals with planning for low load factor DTS load is in relation to the Northeast region. That load would be categorized either as backup or standby service or as scheduled maintenance service, since it is expected to appear due to a loss of one or more generators due to maintenance or forced outages. The *10-Year Plan* specifically notes for the Fort McMurray Area, on page 101:

The load and generation development are expected to generally balance each other. There is, however, potential for the situation to swing from being balanced to turn into a load center or a supply area rapidly. Not only are transmission thermal overloads and voltage fluctuations a concern, but also transient swings and increased inertia of the larger Fort McMurray electrical system may impact the stability of the transmission system.

However, the Northeast region projects are also required because the existing import and export limits for the region are less than the contracted maximum capacities forecast for the region. As with other projects in the *10-Year Plan*, the Northeast region projects

address issues which affect most, if not all, customers in the region, rather than being targeted to, for example, specific categories of partial-requirements customers. This result is to be expected for system projects addressing transmission issues in the province.

The AESO also notes that many of the thermal overloads, voltage criteria violations, and special issues identified in the *10-Year Plan* are exacerbated by short-duration, intermittent, and unexpected load increases such as those arising from partial-requirements customers. The transmission conceptual projects identified in the *10-Year Plan* will reduce the risk of uncontrolled loss of load, including that of partial-requirements customers, in those regions.

Preamble: Page 34 of 53 says:

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. (Emphasis Added)

Reference: Section 4.6 Standby Service

Request:

- (a) Please provide all working papers and calculations that were used to estimate that 1,500 to 2,000 MW of load that could request backup service. Please explain the AESO's methodology and make visible all assumptions.
- (b) What rate does this 1,500 to 2,000 MW load currently use?

Response:

- (a) Please refer to the response to Information Request BR.AESO-004.
- (b) Backup load which currently exists is served on Rate DTS. The AESO also expects some of the potential backup load would represent new, incremental load for which customers currently avoid transmission charges through equipment shutdown, coordination of outages, on-site backup supply, and other measures. The AESO understands customers have implemented these measures because they are more economical than serving the backup load on Rate DTS. If a significantly less expensive backup rate was offered, the AESO would expect some of this load may appear as incremental load on the transmission system.

Preamble: Page 33 of 53 says:

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.

(Emphasis Added)

Reference: Section 4.6 Standby Service

Request:

Respecting confidentiality, please provide for each of the two identified groups of back-up loads a breakdown of the native behind the fence load, the typical DTS contract capacity, the typical back-up load served by imports from the AIES and the expected frequency and duration of imports from the grid.

Response:

The AESO does not have specific knowledge of individual customers' responses to the DTS rate structure in managing their backup service requirements. The two responses described in the quoted paragraph summarize the AESO's understanding from discussions with customers about backup service; these discussions were general and did not include the specific information requested.

There are 120 PODs where monthly peak demand exceeds contract capacity by, on average, 30%. Those PODs total about 2,000 MW of monthly peak demand. The AESO expects that those PODs include customers who require backup service but contract for normal load as described in the second bullet point in the quoted paragraph.

At the remaining 365 PODs, totaling about 6,400 MW of monthly peak demand, monthly peak demand generally does not exceed contract capacity. Those PODs are therefore expected to include customers who require backup service and contract for backup load conditions as described in the first bullet point in the quoted paragraph.

Preamble: Page 34 of 53 says:

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

Reference: Section 4.6 Standby Service

Request:

- (a) Please describe the number of PODs, the type of customer and the areas where the AESO is currently observing concurrent usage above contract.
- (b) Please provide a summary of the constraint management rules being proposed by the AESO and explain the principles which guide the development of these rules.
- (c) What transmission expansions or enhancements is the AESO planning to address the usage above contract?

Response:

- (a) Please refer to the response to Information Request EnCana.AESO-028. The AESO has not compiled concurrent usage data for individual PODs, and doing so would require an unreasonable expenditure of time and effort.
- (b) A summary of the constraints management steps as detailed in the proposed Transmission Management Rule is as follows:
 - (i) Using the effective factor as a guideline, determine the assets which are loads, generating units and interconnections to be included in the following steps.
 - (ii) Issue directives to generating units that are upstream of the transmission constraint directing them to curtail to the amount specified in their system access service agreements as their supply transmission service levels.
 - (iii) Curtail opportunity export services downstream of the transmission constraint and curtail opportunity import services upstream of the transmission constraint.

- (iv) Curtail demand opportunity service loads downstream of the transmission constraint.
- (v) Curtail each generating unit's trigger volume that is upstream of the transmission constraint. If there is more than one generating unit with a trigger volume that is upstream of the transmission constraint, the generating unit with the most recent commitment date must be curtailed first.
- (vi) Dispatch generating units downstream of the transmission constraint which are contracted with the ISO to provide TMR to increase their energy production.
- (vii) Curtail each demand customer's trigger volume that is downstream of the transmission constraint. If there is more than one demand customer with a trigger volume that is downstream of the transmission constraint, the demand customer with the most recent commitment date must be curtailed first.
- (viii) Curtail generating units upstream of the transmission constraint. If there is more than one generating unit upstream of the transmission constraint, the curtailment to each generating unit will be allocated on a pro-rata basis.
- (ix) Issue directives to generating units downstream of the transmission constraint to increase energy production or to begin energy production, if so required by the reliability criteria.
- (x) Curtail demand transmission service loads downstream of the transmission constraint, if so required by the reliability criteria. If there is more than one demand customer downstream of the transmission constraint, the curtailment to each demand customer will be allocated on a pro-rata basis.

The high level principles used to guide the development of this Rule, as described in the Discussion Paper issued in Oct 2005, are:

- The constraint management methodology must be consistent and aligned with the Electric Utilities Act, the Transmission Regulation, and applicable EUB decisions.
 - The AESO reliability criteria must be recognized; any proposed changes to the reliability criteria must be approved by the AESO.
 - NERC and WECC reliability standards, policies and criteria must be complied with, unless noted as an exception by the AESO.
 - Constraint management must ensure reliability of the AIES, and must be consistent and aligned with the fair and competitive electricity markets in Alberta.
 - The time horizon for constraint management is within the operations planning and real time operations timeframes, typically within two years, except when planning solutions take longer to complete.
 - Application of constraint management in real time must be clear and precise, and must be reasonably manageable by the AESO System Controller.
- (c) The AESO uses the actual metered loads as a basis for the load forecast used in regional transmission planning studies. This load forecast may contain usage above contract. Transmission expansions or enhancements are not planned to address specific usage above contract.

Preamble: At page 37 the application says:

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.
(Emphasis Added)

Reference: Section 4.6.2 Backup Service Costs

Request:

- (a) What is the existing amount of 'back-up load' in the Northeast?
- (b) Please explain in detail the rationale for planning to add an additional 425 MW of transmission capacity to accommodate the existing plus 1,100 MW of new 'backup load'. Explain how the AESO arrived at an amount of 425 MW and why the reliable operation of the grid requires that it plan capacity for 'partial requirement' usage. (Please use the most recent values from the NE Transmission Development studies if they differ from the data reported in the Application.)
- (c) If the Board were to direct the AESO to conduct a cost-of-service study related to standby/backup load use of the transmission system explain how the AESO would conduct such a study, with attention to an outline of the approach, the data requirements and the means of differentiating such customers from other intermittent users of the transmission system.

Response:

- (a) The estimated 2006 total of all DTS contracts in the Northeast (Fort McMurray region) is approximately 580 MW of which the AESO has estimated that approximately 300 MW is "back-up load" or low load factor loads.
- (b) Using the values presented in the October 2, 2006 presentation, the AESO proposed a method that would support 425 MW out of the possible 1,100 MW of low load factor (LLF) load (2016 forecast values). The 425 MW is equivalent to the sum of the largest

LLF load (250 MW) plus a loss of the largest area generator (175 MW). In addition, there will be variations in the local area generation due to derates and operating requirements. This is equivalent to adding 270 MW of load. In total, approximately 1510 MW of transmission capacity would be required on the transmission system between Fort Saskatchewan and Fort McMurray. This is only one of many different methods being investigated by the AESO. The Northeast development plan process is currently underway with stakeholders. The current 2016 forecast of all DTS contracts in the Fort McMurray region is approximately 2,040 MW of which the AESO has estimated that approximately 1,190 MW is low load factor load.

- (c) The methodology, approach, and data requirements would depend on the EUB's direction, if any.

Preamble: The AESO proposes a completely new Construction Commitment Agreement pro forma.

Reference: Section 6 – Terms and Conditions of Service; Section 7 – Proposed Tariff

Request:

- (a) Please provide a summary as to the purpose of the Construction Commitment Agreement (CAA), including all situations when and the reasons why the AESO would require a customer to execute such.
- (b) Schedule A refers to “Project Work” and Schedule B to “Security”. Please provide an exhaustive list of work and security that would be used by the AESO in each instance.

Response:

- (a) The Construction Commitment Agreement (CCA) as defined in Article 1 of the AESO’s Terms and Conditions is as follows:

A financial security agreement made between the Customer and the TFO or between the Customer and the AESO prior to arrangements for new facilities required to accommodate the provision of System Access Service to the Customer or an increase thereto.

The AESO is a not-for-profit entity and does not have the ability to absorb financial losses. Consequently customers are required to execute a CCA in circumstances where transmission development is required to interconnect a customer who has applied for system access. If the project is cancelled due to a cancellation event, the CCA and customer security ensures the AESO will be reimbursed by the customer for all cancellation costs, thus avoiding the risk that such costs would have to be recovered by the AESO from customers through its rates.

Please refer to the response to Information Request BR.AESO-011 for additional information.

- (b) Schedule A is intended to define the scope of the proposed transmission development which is required to provide the customer interconnection. This scope forms the basis for the agreed construction commitment. Typically the work includes engineering, materials acquisition, construction and numerous related activities to provide the proposed transmission facilities such as transmission lines, substations and telecommunications.

Security as it is interpreted in Schedule B is defined in Article 6.2 (a) of the Terms and Conditions.