

## AESO INFORMATION REQUESTS TO TCE

### AESO.TCE-001

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**Preamble:** The AESO's 2005 DTS rate recovered all demand- and customer-related costs through billing capacity charges. The AESO's 2006 DTS rate recovers demand-related costs partly through coincident peak demand charges and partly through billing capacity charges, and customer-related costs through customer (\$/month) charges.

**Reference:** Evidence of TCE, Page 7 of 46, Lines 19-22

"As a result, the large shifts in the cost structure being proposed by the AESO must be understood in the context of looking at the same assets differently than in the past, rather than as a result of underlying changes in the costs themselves."

**Request:**

- (a) Please explain if TCE considers the change from the 2005 DTS rate to the 2006 DTS rate to be a "large shift".
- (b) Does TCE believe the changes from the 2005 rate to the 2006 rate in the AESO's 2005-2006 GTA proceeding were appropriate?

### AESO.TCE-002

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**Reference:** Evidence of TCE, Page 10 of 46, Lines 30-31 and Page 16 of 46, Lines 2-4

"It is preferable to allocate fixed costs on a demand allocator and refine that allocator to reflect diversity."

"TransCanada considers the On-Peak energy method constrained to hours where the majority of the transmission lines peak to have the highest ranking from a cost causation perspective."

**Request:**

Please explain TCE's preference to allocate fixed costs on a demand allocator in the context of TCE's suggested assignment of the highest ranking from a cost causation perspective to the on-peak energy method.

### **AESO.TCE-003**

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**Preamble:** The evidence of Alan Rosenberg on behalf of ADC, specifically Exhibit AR Schedule 6 and the related discussion on page 38, provides the frequency that transmission lines were loaded at 90% or more of their annual peaks in each hour of the day during summer and winter months.

**Reference:** Evidence of TCE, Page 10 of 46, Lines 25-27

“...it is not difficult to reduce the coincidence to a reasonable number of peak hours by using a proxy to when these peaks occur, either in the form of the 12 CP method or some on peak energy method.”

**Request:**

Please reconcile TCE’s position that a 12 CP method is a good proxy for transmission component peak loads with ADC’s analysis which shows that transmission line peak loads are distributed with fairly consistent frequency over hours 9 through 23 in the summer and over hours 9 through 22 in the winter.

### **AESO.TCE-004**

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**Reference:** Evidence of TCE, Page 13 of 46, Lines 26-27

“...(3) the non-coincident peak method treats opportunity loads the same as firm loads.”

**Request:**

- (a) Please explain how opportunity loads are treated the same as firm loads.
- (b) Please clarify what types of loads TCE is referring to as “opportunity loads”, and explain how these loads are similar to or differ from loads which qualify for the AESO’s DOS rates.

### **AESO.TCE-005**

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**Reference:** Evidence of TCE, Page 14 of 46, Lines 20-22

- “1. TransCanada eliminated the statistically irrelevant data that examines all 8,760 hours by only examining the top 10 peaks for each transmission line under consideration.”

**Request:**

Please explain whether TCE is recommending that a customer who avoids the top 10 peaks for each 240 kV transmission line (at most 790 hours of the year) should be charged no costs related to the bulk transmission system.

### **AESO.TCE-006**

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**Reference:** Evidence of TCE, Page 16 of 46, Lines 37-42

“The AESO has only undertaken a cursory examination of future costs by reviewing the drivers for new transmission additions on the system. These drivers are in the context of a marginal cost study (not an embedded cost study) since they relate to some future projects and should be accorded limited weight when designing rates to recover embedded costs.”

**Request:**

- (a) Please explain if TCE would consider the cost drivers identified in Appendix G to TCE’s evidence to be based on examinations of future loads and future additions to the transmission system.
- (b) Please explain how the drivers identified in Appendix G are different from those identified in the examination of future costs provided by the AESO.
- (c) Please comment on why a current examination of future costs should be “accorded limited weight” compared to an examination of future costs conducted many years ago.

### **AESO.TCE-007**

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**Reference:** Evidence of TCE, Page 16 of 46, Lines 39-42 and Page 20 of 46, Lines 33-34

“These drivers are in the context of a marginal cost study (not an embedded cost study) since they relate to some future projects and should be accorded limited weight when designing rates to recover embedded costs.”

“However, the transmission cost structure in Alberta has not materially changed in recent years.”

**Request:**

Please explain why, if the transmission cost structure has not materially changed in recent years, a cost study would not give similar results whether based on historical conditions, current conditions, or future conditions.

### **AESO.TCE-008**

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**Reference:** Evidence of TCE, Page 17 of 46, Lines 4-5

“The key problems with the cost of service study described in Appendix F are summarized below....”

**Request:**

- (a) Please identify which of the “key problems” listed by TCE apply to cost of service studies in general and which apply specifically to the cost of service study filed by the AESO.
- (b) Please identify which of the “key problems” listed by TCE apply to the “more refined analysis” provided by TCE.

### **AESO.TCE-009**

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**Reference:** Evidence of TCE, Page 18 of 46, Lines 26-28

“Loads that shift from on-peak periods to off-peak periods improve system utilization by increasing the usage levels of the same transmission facilities, thereby potentially benefiting all other customers with lower rates.”

**Request:**

- (a) Please explain whether a non-coincident peak demand charge provides a price signal to a customer to maintain a flat load profile.
- (b) Please comment on whether a flat load profile results in efficient and cost-effective use of the transmission system.

### **AESO.TCE-010**

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**Reference:** Evidence of TCE, Page 21 of 46, Lines 16-18

“Participants in the Alberta power industry have expressed concerns in recent years on the need for more stability and to reduce the amount of instability and volatility of pricing.”

**Request:**

Please discuss the need for stability and predictability of prices in the context of TCE’s recommendations to continue to use the 12 CP method for the 2007 rates and an on-peak energy method in the future.

### **AESO.TCE-011**

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**Reference:** Evidence of TCE, Page 22 of 46, Lines 8-10

“It is useful to review the historical decisions, supported by expert testimony, from the past that relate to the bulk transmission system.”

**Request:**

Please explain how transmission system costs were billed to and recovered from end-use customers in the decisions reviewed by TCE, especially with respect to the determinants used to calculate bills to large industrial customers.

### **AESO.TCE-012**

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**Reference:** Evidence of TCE, Page 16 of 46, Lines 34-37; Page 22 of 46, Lines 12-13; and Page 22 of 46, Lines 15-17

“Historical drivers for costs should be given significant weight in a cost of service study because they are based on facts and expert advice that was the basis of regulatory approvals and because they relate directly to the costs included in the embedded cost of service study.”

“In the early part of the Electric Energy Marketing Agency (‘EEMA’) era, costs were allocated on the 1 CP method.”

“Still prior to industry restructuring and in the latter part of the EEMA era, the transmission costs were ‘allocated on the basis of a weighted CP designated as three winter months/nine non-winter months (3W/9NW).’”

**Request:**

- (a) Please discuss the change from the 1 CP method to the 3W/9NW method in the context of TCE’s recommendation that historical decisions be given significant weight.
- (b) Please confirm that in the “EEMA era” referred to, industrial customers were not billed on either a CP or 3W/9NW basis.

### **AESO.TCE-013**

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**Reference:** Evidence of TCE, Page 24 of 46, Lines 22-23

“The continued use of the 12 CP method for bulk transmission costs will result in the greatest rate stability to customers since this is the method currently in use.”

**Request:**

Please explain whether TCE considered rate stability to be an important criterion in the determination of the AESO’s 2006 tariff.

#### **AESO.TCE-014**

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**Reference:** Evidence of TCE, Page 26 of 46, Lines 33-34

“Figure 1 below provides a survey of jurisdictions and the demand allocation method in use in those jurisdictions.”

**Request:**

Please identify which jurisdictions are most relevant when assessing the comparability of the AESO’s rates, and explain why.

#### **AESO.TCE-015**

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**Reference:** Evidence of TCE, Page 37 of 46, Lines 26-29

“Put another way, there are no increases [in] fixed costs on the transmission system for opportunity service exports, regardless of how they are allocated. The cost of service for serving an opportunity service customer should not include any fixed costs.”

**Request:**

- (a) Please explain if TCE agrees that static VAR compensators, capacitor banks, transformation at 102S Langdon substation, and other equipment has been installed and is operated to support both export and domestic services.
- (b) Please confirm that clause 8(1)(g) if the Transmission Regulation requires the AESO to expand and enhance the transmission system so that inter-ties can import or export electricity at or near their path ratings.

#### **AESO.TCE-016**

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**Reference:** Evidence of TCE, Page 41 of 46, Lines 1-2

“The WECC Standard for Operating Reserves sets out that each Balancing Authority shall maintain minimum Operating Reserves....”

**Request:**

- (a) Please confirm that the WECC Standard also provides for Reserve Sharing Groups, and that the standard applies to such a group as a whole rather than to individual members of the group.

- (b) Please confirm that OPP 405 defines the contingency reserve sharing requirements applicable to the AESO as a member of the Northwest Power Pool Reserve Sharing Group.

#### **AESO.TCE-017**

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**Reference:** Evidence of TCE, Page 43 of 46, Lines 20

“1. the AESO occasionally reduces or eliminates exports within the hour”

**Request:**

Is it TCE’s understanding that this approach is different than that used in other jurisdictions, when inter-tie flow is scheduled at levels near the inter-tie capacity?

#### **AESO.TCE-018**

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**Reference:** Evidence of TCE, Page 43 of 46, Lines 23-24

“3. Export ATC is only reliably available in off-peak hours and to a limited degree and occasionally in on-peak hours.”

**Request:**

- (a) In what percentage of on-peak hours has export ATC been non-zero since August 2006 (when the determination of ATC was revised)? Please provide the basis for your response.
- (b) What has been the average level of export ATC in on-peak hours in which it was non-zero since August 2006? Please provide the basis for your response.

#### **AESO.TCE-019**

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**Reference:** Evidence of TCE, Appendix A, Page 2 of 13, Lines 24-25

“Figure A1 below shows the percentage of hours for each hour of the day where ATC was available and consequently the system was not constrained.”

**Request:**

- (a) Please confirm that Figure A1 actually shows the percentage of hours where Export ATC was not available rather than when it was available.

- (b) Please confirm that export ATC may not be available for reasons other than the SOK-240 limit being reached, such as steady-state voltage and voltage stability constraints.

#### **AESO.TCE-020**

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**Reference:** Evidence of TCE, Appendix A, Page 6 of 13, Page 8 or 13, and Page 9 of 13

Figure A5  
Figure A7  
Figure A8

**Request:**

Please provide the units for the vertical axes in the referenced figures.

#### **AESO.TCE-021**

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**Reference:** Evidence of TCE, Appendix A, Page 6 of 13 and Page 8 of 13

Figure A5  
Figure A7

**Request:**

Please clarify that the analysis conducted for these figures:

- (a) included only the 10 hours of highest loading for each of the 240 kV lines (that is, at most 740 hours based on the 74 lines provided in the AESO's data set), and
- (b) excluded any of those hours in which the SOK-240 limit was not reached as indicated by the availability of any amount of Export ATC.

## **AESO.TCE-022**

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**Preamble:** The monthly AIL system peaks in 2005 (as provided by the AESO in Appendix D to its 2007 GTA) occurred twice in each of hours ending 14, 15, and 16; once in each of hours ending 19 and 20; and four times in hour ending 18.

The monthly AIL system peaks in 2004 (as provided by the AESO in Appendix D to its 2007 GTA) occurred once in each of hours ending 14 and 15; twice in each of hours ending 16 and 17; and three times in each of hours ending 18 and 20.

**Reference:** Evidence of TCE, Appendix A, Page 10 of 13 and Page 11 of 13

Figure A9  
Figure A10

**Request:**

- (a) Please clarify whether Figure A9 includes summer hours only (as indicated by its title) or all hours (as indicated in the text).
- (b) Please confirm that the six highest hours of peak transmission line flows for 2005 as illustrated in Figure A9 were hours ending 14, 11, 12, 13, 9, and 21, in descending order.
- (c) Please confirm that the six highest hours of peak transmission line flows for 2004 as illustrated in Figure A10 were hours ending 14, 15, 16, 11, 13, and 17, in descending order.
- (d) Please comment on the differences between the hours of AIL system peaks provided by the AESO and the highest hours of peak transmission line flows determined by TCE.

## **AESO.TCE-023**

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**Preamble:** In Decision 2005-096 on the AESO's 2005/2006 General Tariff Application, the EUB stated on page 17:

...the Board considers that cost causation must be afforded the most weight in attempting to balance these sometimes competing principles when evaluating a proposed rate design. That is, in reviewing a proposed rate design, the Board finds that it is critical that the rate design proposed ensures that a customer that causes a cost must be prepared to pay that cost. The principle of rate shock, which can conflict with this cost causation principle, must take a secondary consideration to cost causation in arriving at an appropriate rate design. The balance of the criteria can usually be seen as complimentary to cost causation. On balance, if rates reflect causation, barring unusual regulatory events such as regulatory lag or a dramatic change in cost structure, there should be little need to be concerned about the principles of rate shock and gradualism.

**Reference:** Evidence of TCE, Appendix C, Page 3 of 4, Lines 4-20

In the past, the Board has described the way in which it weighs the various rate design criteria as follows:

The weight to be given to each criterion will, of course, vary depending on the goals and objectives of the service provided and intended to be covered by each rate classification. The Board, in its review of each rate classification, will apply the appropriate weight to each criterion with the overall objective of determining just and reasonable rates while recognizing the need to maintain a level playing field consistent with achieving a competitive market for the provision of electric generating service with the province, as mandated by the EU Act. The Board will also review the cost allocation used to support the rates to ensure that the cost of service is appropriately determined to promote efficient and cost-effective usage of transmission facilities. [EUB Decision U97065, page 611-612]

TransCanada agrees that the weight given to each criterion will vary depending on the goals and objectives of the service provided. The specific circumstances in a particular rate design process will also contribute to the weight given to each criterion."

**Request:**

Given that the EUB has expressed somewhat different views regarding rate design principles in Decisions U97065 and 2005-096, please explain which Decision TCE considers should be given greater weight when assessing rate design principles in the AESO's current rate application.

**AESO.TCE-024**

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**Reference:** Evidence of TCE, Appendix F, Page 8 of 8, Lines 11-13

“The lack of use of direct assignment of assets where a customer class is known to specifically use a particular asset class, or the converse, they are known not to use a particular asset class creates inaccuracies in the cost study.”

**Request:**

Given that the AESO has a single DTS rate class to which wires costs are allocated, please explain what assets TCE considers could be directly assigned, and to which customer classes.

**AESO.TCE-025**

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**Reference:** Evidence of TCE, Appendix G, Page 2 of 6, Lines 7-11

“1. The major drivers for new bulk transmission when constructed for load growth are the annual peaks and in some situations, the winter and summer peaks either for the AIES peak load, for the Electric Utility or for the specific area. From a cost allocation perspective, the demand allocation method representing 1 CP or a summer/winter CP would best capture these cost drivers.”

**Request:**

- (a) Please clarify whether TCE recommends the use of a 1 CP methodology to allocate demand-related costs for transmission line additions. If not, please summarize the method TCE recommends and the reasons why.
- (b) Please explain TCE's recommendation in part (a) in the context of TCE's suggestion that the on-peak energy method has the highest ranking from a cost causation perspective, as discussed on page 16 of 46 (lines 2-4) of its evidence.