

Title: Functionalization

Preamble: At the time of the last GTA, the AESO witness, Mr. Reimer, stated high voltage switch gear and bus work would be part of the local system, and that just the transformers and low-voltage bus work would be POD-related costs. [T241;L2 2006 GTA]

Reference: T241;L2, 2006 GTA

Request:

Please indicate how high voltage switch gear and bus work were functionalized in the application and provide the rationale for the proposed functionalization. If these items are included under POD costs please provide an estimate of the amount of the shift in costs if high voltage switch gear and bus work were functionalized as part of local system.

Response:

The AESO has not proposed any changes to the functionalization that was completed in the original *Transmission Cost Causation Study*. Mr. Reimer was commenting on a different functionalization that could be completed if additional cost data had been available. There has been no additional cost data that would allow the variation in functionalization discussed by Mr. Reimer.

Please refer to section 4 of the *2006 Transmission Cost Causation Update* provided as Appendix C to the AESO's 2007 GTA filed on November 3, 2006.



Title: Billing Determinants

Preamble: Growth in Billing Determinants

Reference: Section 4, page 2

Request:

Please provide and compare the forecast 2006 billing determinants to the forecast 2007 billing determinants.

Response:

Please see attached Schedule CG.AESO-002.

Title: Transmission Cost Functionalization

Preamble: Dual-Use Substation Costs

Reference: Section 4.3.1

Request:

- (a) Please discuss the major reasons dual-use substation costs could not be functionalized on the basis of TFO cost data and indicate the direction of on-going and future analysis.
- (b) Please elaborate on the use of the substation fraction to apportion costs between demand and supply and functionalized between POD and the bulk system. How do supply related costs functionalized as bulk system costs provide a basis for cost recovery of these costs through supply customers rather than demand customers?

Response:

- (a) Dual-use substation costs were functionalized on the basis of the substation fraction in addition to the TFO cost data. Dual-use substations could not be functionalized only on the basis of the TFO cost data because the substation provides two functions but TFOs only record the cost of the total substation, without apportioning part of the cost to supply and the remainder to load.
- (b) The substation fraction is a stable and reasonable means of apportioning the costs of a substation that serves both supply and load. Substation costs determined to be supply-related through application of the substation fraction were functionalized as bulk system costs. The net impact was a small reduction to POD function costs and a small increase to bulk system function costs, as detailed in section 6.3 of the *2006 Transmission Cost Causation Update*.

Substation costs determined to be supply-related are generally recovered from supply customers through customer contributions. Those contributions were also allocated to the bulk system, as detailed in section 6.3 of the *Update*.

The recovery of costs from supply customers is generally governed by the *Transmission Regulation* and the AESO's Terms and Conditions of Service.

Title: Bulk Transmission System Cost Classification and Cost Recovery

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

Reference: Section 4.3.2, page 11

Request:

- (a) Please provide the AESO definition of coincident peak.
- (b) Please provide a discussion of alternate coincident peak considerations with resulting impacts on rate design and include 1CP, 12 CP, 120 CP and on-peak billing hours.
- (c) Please provide detailed reasons for the AESO decision that recovery of demand-related bulk system costs on billing capacity is the most appropriate approach.
- (d) Since distributors tend to flow through the AESO rate design to end-use customers, please describe the impacts of a billing capacity determinant on seasonal customers. What adjustments to the billing capacity determinant can be made to mitigate the adverse effects on seasonal customers?

Response:

- (a) Coincident peak as discussed in the quoted reference refers to customer demand which occurs at the time of the overall peak demand on the Alberta Interconnected Electric System (frequently referred to as the system peak demand).
- (b) Please refer to the response to Information Request BR.AESO-002 (a).
- (c) Please refer to the discussion on page 12 of section 4 of the AESO's 2007 GTA.
- (d) The AESO does not consider its proposed DTS rate design to have any adverse effects on a distributor's seasonal customers.

As noted on lines 42-46 on page 11 of section 4 of the AESO's 2007 GTA, "...the bulk transmission system, on average, exhibits no distinct...monthly usage patterns. Loading

on the bulk transmission system varies...from 93% to 111% of average on a monthly basis. In effect, some bulk lines are heavily loaded, and some are lightly loaded, in...every month of the year." Seasonal loads at transmission PODs should therefore pay demand charges similar to that of non-seasonal loads.

The AESO further notes that its proposed DTS rate design recovers 48.6% of bulk and local system costs on a usage (\$/MWh) basis to recognize variations in load factor. Since seasonal loads have low load factor (and low energy usage) in off-season months, lower transmission costs will appropriately be attributed to them in those months under the proposed rate design.

In conclusion, if a distributor flows through the AESO's rate design to end-use seasonal customers, those customers will pay an appropriate amount of transmission costs.

Title: Bulk System Cost Classification

Preamble: In effect, some bulk lines are heavily loaded, and some are lightly loaded, in every hour of the day and every month of the year. Load in every hour is therefore important, since in every hour some bulk lines will be heavily loaded and will need reinforcement if additional load is to be accommodated. There appears to be no basis to support cost recovery based on loading at different times of day and different months of the year.

Reference: Section 4.3.2, Page 11, Appendix D

Request:

- (a) In the context of the interconnected bulk system, please explain why certain lines would have higher than average loading and others below average loading. In other words, why would the higher loading on certain lines not result in increased flows in lines with lower loading given the interconnected nature of the bulk system?
- (b) Please explain why the AESO considered it appropriate to carry out its analysis in Appendix D having regard to the average loading based on all lines rather than only the lines with above average loading or those with critical loading.
- (c) Please indicate whether the results of the Bulk system analysis and AESO's observations thereon would be different if the average did not reflect a weighting for length of lines. If so, please provide revised calculations/graphs with the average not reflecting a weighting for length of line and comment on this alternative.
- (d) Please identify the lines with above average loading from Appendix D and compare the profiles for these lines with the AIL load by way of graphs similar to those in Appendix D. Identify the proportion of total load represented by lines with above average loading and comment on the significance of this analysis for classification purposes.
- (e) Please identify the lines with above average loading from Appendix D and compare the load profiles for these lines with the load profiles applicable to each POD by way of graphs similar to those in Appendix D. Typical PODs may be used if analyzing all 485 PODs would be cumbersome. Having regard to this analysis, please comment on why the AESO considers the highest metered demand (NCP) in the AESO's DTS rate provides a better match between bulk system peaks applicable to critical bulk system lines than AIL peaks.
- (f) Please provide an estimate of the degree of coincidence (percentage) between NCP demands at the PODs and the aggregate load profile of bulk system lines with higher than average loading. Discuss whether there is merit to using this degree of coincidence for determining the portion of bulk system costs that may be recovered on the basis of energy, as an alternative to the proposed average and excess method.

Response:

For clarity, the AESO's discussion of "average load, "high-than-average loading", and "lower than average loading" in Appendix D refers to the average load on each individual transmission line, and the variation of that load over time. When considering an individual transmission line, no line has a perfectly flat load profile, and the load on the line will be above the average **for that line** at certain times and below the average **for that line** at other times. The following responses are based on this further clarification.

- (a) Lines are loaded to varying degrees primarily because the transmission system is not a perfectly networked mesh, and secondarily because of the various facilities that affect power flows on a transmission system.

The first and primary reason reflects that, if an area in the province experiences high net load conditions at a particular time, there are usually a limited number of transmission lines which can deliver electricity to the area. For example, there are three lines available to deliver electricity to Fort McMurray: 9L07/55, 9L56/57, and 9L990. The loading on those lines will be determined by the Fort McMurray load, and other transmission lines in other areas of the province cannot "share the load" by directly delivering electricity to Fort McMurray.

There will be direct impacts on other lines in the province of loads in specific areas, however. For example, to meet total provincial demand when Fort McMurray is experiencing high load, generators may be dispatched in southern Alberta. These southern Alberta generators would help meet load requirements in southern Alberta, resulting in an unloading of the north-south lines between Edmonton and Calgary and allowing more Wabamun-area generation to supply the Fort McMurray load. An increase in Fort McMurray load could therefore increase loading on transmission lines to Fort McMurray, decrease loading on the north-south transmission lines, and increase loading on southern transmission lines.

The secondary reason reflects the physical characteristics of the transmission system. Transmission lines are built with different conductors, are of different lengths, and operate at different voltages, while system transformers and other equipment are of different capacities and operate at different voltages. All these physical characteristics interact. Since electricity tends to flow over the path of least resistance, the different lines which could possibly transmit electricity within or to an area will usually be loaded to different levels reflecting each lines overall "resistance" to the flow of electricity.

- (b) As explained in the preface to this response, the AESO analyzed loading on individual lines, and presented the results of that analysis based on the average load on each line. Presenting the analysis in that manner allowed all transmission lines to be charted together in a single graph.

The AESO analysis included all transmission lines because, first and foremost, the AESO must allocate the costs of **all** transmission lines to transmission system loads through its tariff.

In addition, while some lines are nearing capacity limits and will be reinforced in the near future, others have capacity sufficient for forecast needs for some time. This is common in a system where capacity is generally added in relatively large increments. However,

over time, the load will increase on many transmission lines which currently have sufficient capacity, and these lines will also need reinforcement or replacement. Allocating costs based on lines which are currently heavily loaded could therefore result in unstable allocation, since the heavily-loaded lines would change over time as the transmission system is reinforced and expanded and as load and generation changes throughout the province.

- (c) The results of the bulk system analysis and the AESO's observations would not be materially different if the average over all lines was not weighted by length. An example of the effects of weighting by line length is provided on page 19 of the *2006 Transmission Cost Causation Update* included as Appendix C to the AESO's 2007 GTA. The correlation between individual bulk line loading and total Alberta Internal Load was 8% for 2005 and 1% for 2004 when weighted by line length, and 12% for 2005 and 7% for 2004 when not weighted.

However, the AESO considers weighting by line length to provide the most appropriate averages when analyzing values over all bulk transmission lines. Bulk lines range in length from less than 1 km to over 400 km. It would be inappropriate to consider all lines to equally impact costs when examining average values.

- (d) As explained in the preface to this response, the AESO analyzed loading on individual lines, and presented the results of that analysis based on the average load on each line. The load on each line was therefore above the average **for that line** at certain times and below the average **for that line** at other times. "Above average loading" therefore applies to all lines at certain times, and no sub-grouping of the Appendix D analysis is required.
- (e) Please see parts (b) and (d) above. Please refer to the responses to Information Requests ADC.AESO-005 (b) and IPCAA.AESO-022 for additional information.
- (f) Please see parts (b) and (d) above. Please refer to the responses to Information Requests ADC.AESO-005 (b-d) and EnCana.AESO-012 (b) for additional information.

Title: Bulk Transmission System Cost Classification and Cost Recovery

Preamble: The billing determinant which appropriately recognizes that demand in every hour is important is non-coincident peak (NCP) demand, defined as highest metered demand in the AESO's DTS rate. NCP cost recovery signals that demand in any interval during the billing period could cause costs on the bulk system. Similarly, since there are no distinct monthly usage patterns on the bulk system, demand in any month could cause costs on the bulk system. The AESO therefore considers it appropriate to incorporate a demand ratchet in the bulk system billing determinant. Finally, to the extent that the bulk system is planned to meet future loads on the system as indicated in part by customers' contracted capacity, the AESO considers that bulk system billing should include a contract capacity component.

Highest metered demand, demand ratchet, and contract capacity constitute the billing capacity used for the demand component of the local system and POD charges in the current DTS rate. The AESO proposes that billing capacity also is an appropriate billing determinant for the recovery of bulk system costs. The billing capacity determination is proposed to remain the same as in the current DTS rate; that is, it is the greatest of the highest metered demand in the billing period, 90% of contract capacity, or 90% of the peak demand in the prior 24 months.

Reference: Section 4.3.2, page 12

Request:

- (a) If demand in every hour is important, why is energy not the most appropriate allocator?
- (b) Please provide reasons for the proposed use of a demand ratchet.

Response:

- (a) As explained just prior to the quoted reference on page 12 of section 4 of the AESO's 2007 GTA:

An energy (\$/MWh) charge indicates that total throughput on the bulk system is the most important cost consideration. This is clearly not the cost driver for the bulk system; individual bulk lines and other equipment are designed to meet maximum demand requirement, not total throughput.

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

- (b) Demand ratchets are generally used to allocate the cost of fixed assets to customers over time. The fixed assets must provide sufficient capacity to accommodate the customer's peak load in the month incurred, but also remain in place in future months even if the customer's load is less. This description applies to the bulk transmission system, and demand ratchets appropriately allocate the cost of the bulk system to customers.

Title: Transmission Point of Delivery Cost Classification

Preamble: Raw Cost Function

Reference: Section 4.3.4 and Section 6, page 19 of 47; Appendix G

Request:

- (a) Please provide all supporting data for Figure 1, Greenfield Projects and DTS Capacities.
- (b) Please remove the costs for transmission lines in the data from a) above and provide a new Figure 1 for base POD costs.
- (c) The Application indicates “Note that under the current investment policy as set by the EUB, only 2 of 30, or 6% of projects would be fully covered by investment”. Please discuss the cost basis for the existing investment policy and the reasons for the 30 new project cost estimates to be, relatively, so much more expensive.
- (d) Please identify, by project, the 30 projects used in the analysis from the list of projects shown in Project Status in Appendix G.
- (e) Please identify, by project, the subset of 13 projects with DTS capacities of less than 7.5 MW.

Response:

- (a) The supporting data for Figure 1 can be found in “Appendix G – Contribution Study Data”, under the tab labeled “Greenfield”.
- (b) Substation costs that do not include any transmission line costs are provided in Appendix F – Customer Contribution Study, Figure 2 (p. 14).
- (c) With respect to the basis for the current investment policy, the AESO was directed by the EUB in Decision 2005-096 (page 57) to amend the maximum investment level in Article 9.4 to the average cost function of POD costs, using the data in Table 6.1.1 of Section 6 of the AESO 2005/2006 GTA. A simple linear regression was performed on the DTS Capacity and the Project Cost data, and the resulting analysis produced an average cost function for POD related costs of \$2.5 million plus \$100,000 per MW, which is the current investment function.

There are two main differences between the currently approved and the proposed investment functions. The first is with respect to the data used in the underlying cost function. The 2005/2006 cost function is based upon the average costs of un-escalated project costs and “scenario” projects at various load sizes. The project cost data collected on the 30 projects provided in the Customer Contribution Study in this

Application is generally higher as it was derived from actual project costs escalated to 2007 dollars.

The second reason the current investment function is lower than the proposed function is that it is an average function that was not modified such that 80% of projects would not be required to pay a contribution. As described in the Application, this was done for the proposed investment function, and this clearly would result in far fewer projects being covered by investment under the current function as compared to the proposed one.

- (d) Appendix G – Customer Contribution Data, the tab labeled “Greenfield” identifies the project number (column A) of each of the projects used in the analysis.
- (e) Please see Table 1, Section 6, page 21 of the Application.

Title: Transmission Point of Delivery Cost Classification

Preamble: Table 4.3.6

Reference: Section 4.3.4

Request:

- (a) Please provide the supporting details for the derivation of the customer billing determinant.
- (b) For each POD on the system for 2007, please provide the location, size, DTS, STS and Substation Fraction, and billing determinants.
- (c) Please discuss and explain the major cost reclassifications from the original transmission Cost Causation Study to the Contribution Policy Study.

Response:

- (a) The billing determinants included in Table 4.3.6 on page 14 of section 4 of the AESO's 2007 GTA are:
 - 4,854.4 customer-months
 - 32,514.8 MW-months for the first 7.5 MW of billing capacity per customer
 - 82,133.3 MW-months for all billing capacity in excess of 7.5 MW per customer

These billing determinants are provided in Schedule 5.9 of section 5 of the AESO's 2007 GTA, and are calculated from a 2007 forecast of monthly per-POD values completed as described in the forecast methodology description provided as Appendix B to the Application. The AESO views forecast individual customer billing determinants to be confidential information, and does not consider it appropriate to disclose such information publicly.

- (b) Please refer to the response to Information Request IPCAA.AESO-032 (a-c).
- (c) As stated on lines 21-23 on page 14 of the AESO's 2007 GTA, "...the classification based on the detailed examination completed...in the *Contribution Policy Study* differs significantly from that based on the zero-intercept analysis presented in the original *Transmission Cost Causation Study*." The two studies used different cost bases: a detailed examination of costs for 30 recent DTS projects in the *Contribution Policy Study*, and historical transmission property information from TFO records for the *Cost Causation Study*. The studies were independent, and the costs from the earlier study were not "reclassified" into the later study.

For comparison, the AESO provides the cost classification resulting from the two studies summarized from section 4.3.4 of the Application:

Classified Transmission Point of Delivery Costs, % of POD Function

Study Utilized	Total	Classification		
		Demand	Usage	Customer
Contribution Policy Study	100.0%	87.7%	-	12.3%
Cost Causation Study	100.0%	43.1%	0.7%	56.2%

Title: Transmission Point of Delivery Cost Classification

Preamble: Some small loads are interconnected to the transmission system through facilities such as metering transformers rather than load transformers. Such small loads would generally be served through a distribution connection, but were probably close to a transmission line and distant from a distribution line at the time of interconnection.

Reference: Section 4.3.4, page 20

Request:

- (a) Please provide the differences between metering transformers and load transformers, including size and cost.
- (b) What is the typical equipment included in a POD with a metering transformer?

Response:

- (a) These small loads are generally best served by a distribution connection, both technically and economically. This normally involves a load transformer stepping the voltage down from transmission level voltage to distribution level voltage at a substation, a distribution line extending to the customer's location, and a further transformation from distribution level voltage (25 kV) to a customer's service voltage. However, transmission connected metering transformers have been applied in the past to serve small loads under exceptional conditions. Usually these loads are located near an existing transmission line and remote from any existing distribution lines. The cost of using a metering transformer to serve the small load is normally significantly higher than a distribution service provided a distribution system is located in the area.

There is also an issue regarding the availability of backup supply to the customer site. Distribution lines are typically designed such that in the event of a source failure (i.e. substation out of service) the load can be fed from an alternate source. A transmission connected load supplied by a metering transformer generally has no alternate source available. A typical application using a metering transformer to serve a load would be a TFO telecommunications site where there is both a battery and a standby generator in case of a line outage.

A metering transformer is typically a small single phase voltage transformer capable of servicing a load (typically 25-100kVA). As stated in section 4.3.5 page 18 of the AESO's GTA there have been no installations smaller than 7.5MW since 1999 so the AESO does not have recent pricing of metering transformer fed loads. However, it is the AESO's understanding that a 138kV metering transformer would cost less than \$50,000.

A power transformer (as currently applied on the AIES) is a 3 phase transformer with a typical minimum capacity rating of 15/20/25MVA. A 15/20/25MVA power transformer would cost more than \$500,000. Total installed costs might be \$200,000 for the metering transformer and \$3-5 million for a distribution substation (depending on interconnection complexity).

- (b) AESO interprets the question to ask what is the typical equipment installed in a very small-capacity POD in which a metering transformer is used to supply a small amount of power, to power a very small load.

A metering transformer is not frequently applied to serve a POD so there is no standard configuration. However, this type of installation would typically include a pole mounted metering transformer, a fused disconnect to protect the transformer in the event of failure and a revenue meter. A grounding rod or grid would also be required depending on soil conditions. The need for a backup battery system, standby generator, building, fencing, SCADA, and communications would be dependent on the customer's functional and reliability requirements

Title: DTS Interconnection System Charge

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

Reference: Section 4.5.1

Request:

- (a) Please provide a schedule showing how the 50% load factor in 2005 and the 47.3% load factor in 2004 were calculated.
- (b) If the intent of the average and excess method is to reflect the increasing likelihood of an individual customer's contribution to a peak system component demand with increasing load factor, why did the AESO not use load factor at the POD level to calculate the average portion of costs under the average and excess method? Please explain and provide a calculation of load factor based on aggregate NCP demands at the PODs and energy.
- (c) AESO states the average line load factor is likely representative of both bulk and local systems due to the similarity of the systems. Please explain why the recovery of a portion of local system costs on an energy basis is considered appropriate.
- (d) Please explain why the 18.46% of bulk system costs classified to usage in the cost causation study were not considered in designing the tariff for recovery of bulk system costs?

Response:

- (a) The calculation of the length-weighted average load factors was included in the data posted on the AESO website shortly after the filing on December 13, 2006 of the additional analysis of bulk system data provided as Appendix D to the AESO's 2007 GTA. The data, in two large Excel workbooks, is available on www.aeso.ca by following the path **Tariff > Current Applications > 2007 Tariff Application > Additional Information**. If a stakeholder is unable to access the workbooks from the AESO website, please contact April Walters at (403) 539-2463 to arrange for a CD containing the workbooks.
- (b) In the average and excess demand method, the average component is generally determined using the system load factor. Please refer to the response to Information Request IPCAA.AESO-026 for more information.

The average load factor based on aggregate non-coincident peak demands over all transmission points of delivery is 70%, based on actual billing determinants from June 2005 through May 2006.

- (c) Please refer to the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-026.
- (d) Please refer to the response to Information Request IPCAA.AESO-027.

Title: Point of Delivery Charges

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

Reference: Section 4.5.2

Request:

- (a) Given the lack of correlation for the reasons referred to above, please explain why the AESO did not consider developing the cost curve for POD costs having regard to the replacement costs for different sizes of typical standard substation facilities, based on current planning assumptions, rather than using historical costs.
- (b) Please provide a POD cost analysis and a POD cost curve with increasing demand, having regard to the replacement costs for different sizes of typical standard substation facilities based on current planning assumptions and identifying the fixed (example installation costs, radial line cost) and variable (with demand) components separately.

Response:

- (a-b) As noted in PPGA.AESO-005(b), the AESO notes that there are numerous considerations that influence the final interconnection configuration for system access service requests. The AESO suggests that estimated replacement costs for substation facilities do not adequately represent the actual conditions inherent in the construction of each individual construction project. Construction project costs include variability on many levels, including labour, seasonality, and other variables as indicated above. The replacement cost, although a useful estimation tool, does not represent the actual project costs. Where actual project costs are available, these costs would better represent the sensitivity of project costs.

The Customer Contribution Study addresses EUB Directives to compile the current costs of several interconnection project sizes. The final investment function is meant to represent the average cost per MW of capacity. As identified in the AESO 2005/2006 GTA refiling (pp. 42-43), some stakeholders expressed concerns with the accuracy of the data used in the scenario projects, which may not reflect the variability of standard substation configurations on the system. Further stakeholder consultation was held to determine the scope and purpose of the Customer Contribution Study, and the majority

of stakeholders felt that accurate, fully deconstructed actual projects costs were necessary in the development of the investment cost function.

The AESO addressed the stakeholder concerns by using actual project costs, and suggests that providing a POD cost analysis based on replacement costs would not be representative of actual costs.

Title: Point of Delivery Charges

Preamble: To supplement the Greenfield project data representing recent projects, the Customer Contribution Study utilized data for small projects from the Transmission Cost Causation Study to develop an appropriate cost function for load services smaller than 7.5 MW. Based on a minimum-intercept analysis and linear interpolation, the following cost function for projects up to 7.5 MW was established:

$$\begin{aligned} \text{Point of Delivery Costs} = & \quad \$0.947 \text{ million (eq. 2)} \\ & + (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \end{aligned}$$

The reasonableness of this small project cost function was further assessed with a simple linear regression analysis of the data for small projects from the Transmission Cost Causation Study, which provided the following average cost function:

$$\begin{aligned} \text{Average Small Project Costs} = & \quad \$0.940 \text{ million (eq. 3)} \\ & + (\$0.595 \text{ million/MW} \times \text{DTS Capacity}) \end{aligned}$$

Reference: Section 4.5.2

Request:

- (a) Please provide the data and the analysis used to assess the small project cost function from the Transmission Cost Causation Study as described in equation 3. Identify and describe any other sensitivity analysis that would provide greater assurance the proposed small POD cost curve is reasonable.
- (b) By reference to each of the components of a substation, including radial line and buswork, etc., please compare the costs for a hypothetical, but typical, small substation (<7.5MW) with the costs for a hypothetical, but typical, larger than 7.5MW substation and rationalize the components of costs that would explain the steep decline in unit demand costs for larger transformers, as proposed by the AESO.

Response:

- (a) The data and analysis used to assess the small project cost function, including the TFO data provided on small projects, as well as the additional reasonableness test, can be found in Appendix G – Contribution Study Data, under the tab labeled “All Projects”.
- (b) Small project data that was provided for the Transmission Cost Causation Study (TCCS) was used in the Customer Contribution Study to provide additional information on projects of less than 7.5MW capacities. Detailed project cost categorizations are not available for these small projects and the requested comparison cannot be provided.

As described in the Application, the project data for the Customer Contribution Study relied on actual project costs, and not on hypothetical or “scenario” data (as was in part relied on for the 2005/06 investment function). The AESO believes the use of actual project costs is an important feature of the Customer Contribution Study that allows the intent of the EUB’s directives in regards to the investment function to be met.

Title: DTS Interconnection – Point of Delivery Charge

Preamble: With respect to items comprising POD costs, three distinct components are generally included in facilities functionalized as point of delivery:

- i) radial line built solely to interconnect the substation;
- ii) transformation to step down the transmission voltage to lower levels; and
- iii) buswork, switchgear, communication equipment, and site work.

As part of the Customer Contribution Study discussed in section 6 of this Application, the AESO examined in detail the costs for 30 transmission interconnection projects which represent all “greenfield” load-only interconnections occurring from 1999 to 2005. The available data did not provide a breakdown of costs into the three components listed above, although data for radial lines and for substations (including transformation and most buswork, switchgear, communication equipment, and site work) was examined.

Reference: Section 4.5.2, page 18

Request:

- (a) Please provide the costs for each of the 30 PODs separated into transmission and substation cost components.
- (b) For the substation component for each POD, please provide the breakdown between transformation and buswork, switchgear etc. for the PODs where this breakdown is provided in the available data.
- (c) Please provide the breakdown between transformation and buswork, switchgear etc. for those 1999 – 2006 PODs, exclusive of the selected 30, where this breakdown is available.

Response:

- (a) Please see Appendix G of the Application
- (b-c) Upon stakeholder request, the AESO attempted to deconstruct substation costs to the level requested but encountered issues reconciling total substation costs with the detailed substation costs (i.e. buswork, switchgear, transformation etc.) provided by the TFO. The best available data was provided in the final Customer Contribution Study and used in the determination of the recommended cost and investment functions (both of which are provided in Appendices F and G).



Title: Bill Impact Assessment

Preamble: Table 4.5.2 and the individual POD bill impacts in Appendix E

Reference: Section 4.5.3, page 24

Request:

- (a) Please provide the monthly billing demands and usage for each of the PODs provided in Appendix E.
- (b) Please provide a revised Appendix E using only the DTS interconnection charges for comparison purposes.

Response:

- (a) Please refer to the response to Information Request IPCAA.AESO-032 (a-b).
- (b) Please refer to the response to Information Request BR.AESO-003 (a).



Title: DTS Power Factor

Preamble: Downstream Distribution Generation

Reference: Section 4.5.4, page 31

Request:

Please describe and explain the impact of downstream distribution-connected generation on power factor at the PODs.

Response:

Downstream distribution-connected generation may result in a power factor at the transmission substation that is lower than what would arise either from the load on its own or the generation on its own. Consider the following simple illustration:

	Real Power MW	Reactive Power MVar	Apparent Power MVA	Power Factor %
Distribution-Connected Load	15.0	6.0	16.2	93%
Distribution-Connected Generation	(5.0)	0.0	(5.0)	100%
Net DTS Load at POD	10.0	6.0	11.7	86%

Suppose distribution-connected load initially exists at a DTS point of delivery. The load requires 15.0 MW of real power and 6.0 MW of reactive power, resulting in a power factor of 93%. As this exceeds the 90% minimum power factor in the DTS rate, no power factor deficiency charge is assessed.

A generator then connects to the distribution system downstream of the DTS POD. The generator produces 5.0 MW of real power and neither draws nor produces reactive power, resulting in a power factor of 100%.

The net power flow now metered at the DTS POD is 10.0 MW of real power and 6.0 MW of reactive power, resulting in a power factor of 86%. Although the power factors of both the load and the generation individually exceed 90%, the net power factor at the DTS POD is below 90% and a power factor deficiency charge would be assessed.

The apparent impact of the distribution-connected generation is to reduce the power factor at the DTS POD such that a power factor deficiency charge would be incurred, even though the load at the POD has not changed.



Title: Backup or Standby Service

Reference: Section 4.6

Request:

Please provide the bill impact of proposed, versus existing tariffs, on typical standby customers under a number of load factor and size assumptions. Include all calculations in excel format.

Response:

Please refer to the response to Information Request TCE.AESO-041 for a calculation of bills applicable to backup or standby service. The Excel workbook provided as an attachment to that response can be readily modified to provide bill impacts under different load factor and size assumptions.

Preamble: The final effect of the recommended cost function is a smaller fixed component and a larger demand component in the cost function relative to the current tariff structure, which aligns better with cost functions inherent in the design of investment levels and rates of the AESO prior to 2006, of other utilities in Alberta, and of transmission system operators in other jurisdictions.

Reference: Section 6, Terms and Conditions, page 23 of 47

Request:

The CG is interested in the AESO's supporting material for the above statement. Please provide and describe the supporting cost functions and rates for each of the AESO years prior to 2006, each of the other utilities in Alberta, and each of the transmission operations in other jurisdictions that were investigated.

Response:

The referenced statement is intended to suggest that the recommended cost function and corresponding investment function in the Application have been returned to a structure and level such that 80% of projects are expected to be covered by investment, while 20% of projects would be expected to pay some form of a contribution. The AESO understands this rule of thumb has been relied on historically in general in setting investment levels for Alberta utilities. As noted above, the proposed investment function has a smaller fixed component and a larger portion that varies with the contracted capacity. This is directionally consistent with the investment policies of other utilities in Alberta, which are all a function of contract capacity. A comparison of the AESO's contribution policy with those of other Alberta utilities is provided in CG.AESO-020 Attachment to this response. The AESO reviewed the customer contribution policies of several other jurisdictions (e.g. PJM, California ISO, MISO, NY ISO, NB Power, and BC Hydro) and observed that generally, generation customers are required to fully contribute to the entire cost of their interconnection, while contributions for load interconnections are in some cases the full costs, and in others are generally based on a formula that compares the revenue expected from the customer and the cost of interconnection.

Preamble: AltaLink's CIAC was reviewed and assessed as 22% being related to STS service, and 78% being related to DTS service. [Page 48]

The cost data for the TCCS Study was based on 2002/2003 data and does not include all of the Dual Use substations that exist today. [Page 49]

Reference: Cost Causation Study, Section 6

Request:

- (a) Please provide the basis for how the 22:78 ratio between STS and DTS was determined for AltaLink customer contributions.
- (b) The study appears to be relying on 2002/03 for functionalization of contributions. If possible, please provide an updated functionalization of contributions using, and identifying, the most recent available data.

Response:

- (a) The AESO determined the amount of CIAC contributed for STS and DTS interconnections on the basis of the AESO's records for services within AltaLink's service area.
- (b) The contributions which were reviewed were those related to facilities which were included in the original *Transmission Cost Causation Study*, which utilized TFO property data from 2002-2003. It is important to maintain consistent vintage of data for all elements of the cost study, and would be inappropriate to update one piece of data while using different vintage data in other areas.