

Preamble: 4.3.2 Bulk Transmission System Cost Classification

The AESO states:

A significant portion of the analysis completed for the Transmission Cost Causation Update involved the “more thorough review of all those lines comprising the bulk system” required by Direction 4C of Decision 2005-096. PS Technologies first interviewed AESO system planners to discuss transmission paths, requirements to upgrade the bulk transmission system in different areas of Alberta, and causes of maximum stress on bulk transmission lines. This qualitative review was followed by a quantitative analysis of the relationship between loading on individual bulk transmission lines (as representative of maximum stress) and total Alberta Internal Load (AIL).

Reference: Section 4 – 2007 Rate Design, Page 8 of 53.

Request:

- (a) Please provide details of the interviews between PS Technologies and AESO system planners to “discuss transmission paths, requirements to upgrade the bulk transmission system in different areas of Alberta, and causes of maximum stress on bulk transmission lines.”
- (b) Please confirm that the causes of maximum stress on bulk transmission lines in service in 2006 may be different and occur at different times than the causes of maximum stress and timing of that stress when the original approvals were obtained to construct the transmission lines currently in service. If no, please give a full explanation.
- (c) Please confirm that any proposed “requirements to upgrade the bulk transmission system” that were discussed with transmission planners are for transmission assets that are not currently in TFO rate bases nor will be by the end of 2007 (i.e. the test year for the AESO tariffs). The review of discussions with transmission planners should, at a minimum, include the transmission paths identified in Table 1 of the 2006 Transmission Cost Causation Update. If no, please identify any exceptions.
- (d) In deciding on the use of NCP, how much weight was given in these discussions with planners to transmission lines which will be in service in 2008 and beyond? Please confirm that these forward looking discussions would normally be considered part of a marginal cost study? If no, please provide a full explanation.
- (e) Did AESO staff preparing this application conduct their own independent interviews with AESO system planners separate from PS Technologies? If yes, Please provide the same information as requested in (a) through (d) above.

- (f) Please provide a full explanation for why the “quantitative analysis of the relationship between loading on individual bulk transmission lines (as representative of maximum stress) and total Alberta Internal Load (AIL)” was conducted using AIL loads rather than AIES loads, given that behind-the-fence generation acts to reduce the amount of load that is seen at the interface with the AIES.
- (g) Did the AESO attempt to determine if the quantitative analysis of the relationship between loading on individual bulk transmission lines and total Alberta Internal Load or AIES Load in the 2006 Transmission Cost Causation Update was similar to the causes and timing of maximum stress 5 to 15 years earlier or will be similar to the causes and timing of maximum stress 5 to 15 years in the future using planning models? If yes, please provide a summary of the comparison.
- (h) Please confirm that the quantitative analysis left non-firm exports and DOS loads in the load flows. If no, please explain how these loads were removed from the analysis.
- (i) Does the AESO agree that in any hour when an opportunity export is allowed that the 240 kV north south transmission system cannot be stressed to the maximum? If no, please give a full explanation.

Response:

Revisions to part (i) indicated in italics.

- (a) Please refer to the response to Information Request ADC.AESO-003 (d).
- (b) The cause and timing of maximum stress on bulk transmission lines in 2006 may or may not be different than the cause and timing of the anticipated maximum stress at the time of the addition of the transmission line, depending on the line being considered. No study has been conducted to try to ascertain the original rationale for the addition of individual transmission facilities.
- (c) The interviews with the transmission planners were conducted to identify constraints that the planners are currently working on. The alleviation of a constraint may not always require a major transmission addition. The alleviation of a constraint may include some small projects such as, for example, alleviating a clearance constraint in a span of existing line which results in an increased thermal rating for the line that is already in rate base. However, the AESO agrees that the majority of capital additions to address the constraints discussed with transmission planners would not be included in TFO rate bases prior to the end of 2007.
- (d) The question is based on the premise that transmission planning has changed such that future additions are being made based on different rationale than past additions. Transmission planning criteria remain fundamentally the same as in the past. The integration of all past decisions, and the resulting capital additions, results in the embedded cost of the transmission system currently in place. The original *Transmission Cost Causation Study* and the *2006 Transmission Cost Causation Update* are studies considering the embedded cost of the system as currently in place and currently utilized. A marginal cost study generally considers costs arising out of current decisions without regard for the existing costs already in place.

- (e) No, although findings and conclusions of the study were reviewed with AESO system planners.
- (f) The AIL is used because it is public information that is easily accessible on the AESO website.
- (g) No. Please refer to part (d) above.
- (h) Confirmed. Please refer to pages 13 and 14 of the *2006 Transmission Cost Causation Update* (provided as Appendix C to the AESO's 2007 GTA filed on November 3, 2006) for information on DOS, imports, and exports and their impact on the analysis.
- (i) *The AESO generally agrees that in any hour when an opportunity export occurs the SOK-240 limit (a measure of loading on the north-south line defined in OPP 304) would not be at its maximum value, at least in the absence of the export. The AESO notes that the export itself may increase north-south flows such that the SOK-240 limit is reached, depending upon the location of generation dispatched during the export hours.*

For example, in a given hour, if the SOK-240 limit was calculated to be 2,150 MW and the SOK-240 flow was forecast to be 1,950 MW, then the forecast export capability would be 200 MW providing that all of the 200 MW supply dispatched to meet the additional export requirement was located north of the SOK-240 cut plane. If a portion of the 200 MW supply was south of the SOK-240 cut plane then the export capability would be greater than 200, depending on the specific location of the generating units. During real time operation, the posted export capability takes into account the location of the units dispatched per the merit order to ensure that the SOK-240 loading can be maximized.

The AESO also notes that, during high Alberta loading periods (Alberta load above 7,800 MW in summer or 9,000 MW in winter), exports are limited by other constraints such as steady-state voltage and voltage stability. The limits during these times are listed in Tables 3 and 4 of OPP 304 in the AESO's Operating Policies and Procedures, and apply regardless of SOK-240 flow.

Preamble: The AESO states:

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

First, the hourly profiles (the top chart) show that the loading on many lines varies in a very narrow band from about 90% to about 110% in every hour of the day, on average.

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

Reference: Section 4 – 2007 Rate Design, Page 9 of 53.

Request:

- (a) Does the AESO agree that individual lines are planned with sufficient capacity to at least meet the forecast peak demand on that given line and comply with transmission planning criteria? If no, please provide a full explanation.
- (b) Does the AESO agree that lines that peak in the winter and lines that peak in the summer would tend to offset each other's peaks when they are averaged together? If no, please provide a full explanation.
- (c) Please confirm that transmission planners do not typically plan the transmission system for the average of the loads on several transmission lines combined together. If no, please provide a full explanation.
- (d) Please confirm that transmission lines on an individual basis can often have a much wider variation in their hourly load profiles than between 90% to 110% when considered over the course of a year? If no, please provide a full explanation. If yes, please provide a table in Excel spreadsheet format that sets out the ranges relative to the average, by individual transmission line.

- (e) Please confirm that when planners are determining the required capacity of a transmission line, they will largely ignore any hours where the line is not close to peak loading when evaluating thermal constraints. If no, please provide a full explanation.

Response:

- (a) The AESO generally agrees. Please refer to the response to Information Request IPCAA.AESO-035 (a) for additional information.
- (b) When loading is averaged over lines that peak in the winter and lines that peak in the summer, those lines' peaks would tend to offset each other such that the average load profile would appear flatter than the individual line load profiles. However, the AESO did not examine only average load profiles. Profiles of individual 240 kV lines were included in Figure 4.3.5 and in the additional analysis of bulk system data filed on December 13, 2006 as Appendix D to the AESO's 2007 GTA.

The AESO considers that averaging or summing over individual lines, incorporating a weighting by line length, is appropriate for the purpose of designing transmission rates, when the costs of all transmission lines have to be recovered through a single rate that does not vary as a result of location.

- (c) Confirmed. The AESO plans the transmission system for the specific loading on individual lines and not for aggregate loading averaged over several lines (whether together or apart).
- (d) Confirmed. The hourly load on transmission lines and equipment is a function of the system or local area load and generation dispatch patterns.

The load duration curves for individual 240 kV lines were provided on page 17 of the additional analysis of bulk system data filed on December 13, 2006 as Appendix D to the AESO's 2007 GTA. Those load duration curves show a wide range in hourly load for individual 240 kV transmission lines. The data for those curves was posted on the AESO website shortly after the filing of Appendix D. The data, in two large Excel workbooks, is available on www.aeso.ca by following the path Tariff > Current Applications > 2007 Tariff Application > Additional Information. If a stakeholder is unable to access the workbooks from the AESO website, please contact April Walters at (403) 539-2463 to arrange for a CD containing the workbooks.

- (e) Confirmed, where "close to peak loading" refers to peak loading on the transmission line being evaluated and not the system or local area peak load. The determination of required capacity may also be dependent upon summer and winter conditions. The AESO will assess the transmission requirements based upon applicable forecast load and generation dispatch scenarios.

Preamble: The AESO states:

The AESO therefore concludes that the recommended cost function developed in the Customer Contribution Study may not appropriately represent small load services having unconventional interconnections as discussed above. Where small loads are served through unconventional interconnections, the AESO proposes they be eligible for the Primary Service Credit, as discussed in more detail in the following section and in section 4.10 of this Application.

Reference: Section 4 – 2007 Rate Design, Page 20 of 53.

Request:

- (a) Please provide the cost of service theory relied on for using the Primary Service Credit to adjust the rates for small loads supplied by unconventional connections and why a credit based on their actual costs was not used to credit these facilities?
- (b) Please provide the cost of service theory relied on for using the Primary Service Credit to adjust the rates for Isolated Generating Units.
- (c) Does the AESO agree that these isolated services are included in the AESO's revenue requirement to benefit from a cross-subsidy from other transmission customers for "virtual" transmission services. If the AESO disagrees, provide a full explanation.
- (d) Please comment on the understanding that it is generally less expensive to serve these communities with isolated generation than with either transmission or distribution lines.

Response:

- (a-b) The AESO followed the approach generally used in cost of service studies whereby customer classes are first differentiated based on distinct usage or cost patterns, and costs are then attributed to the service provided to customers in each class.

In the case of the Primary Service Credit, the AESO proposes the differentiating feature for PSC eligibility is the absence of TFO-owned conventional transformation equipment. This differentiating feature is shared by the types of interconnections listed on page 22 of section 4 of the AESO's 2007 GTA, and includes small loads served through unconventional interconnections as well as "virtual" transmission services to isolated communities. The costs attributed to PSC services would then be those costs attributed to service under the standard DTS rate, less those costs which are not incurred as a result of the absence of TFO-owned conventional transformation equipment. The applicable rate would accordingly be the standard DTS rate less the Primary Service Credit.

The AESO considers that it would be inappropriate to adjust the rates for small loads supplied by unconventional connections based on each load's actual costs. Customers are charged through average rates for system access service and not for the actual physical system facilities associated with their specific interconnections. Application of the Primary Service Credit recognizes a distinct cost pattern relevant to services eligible for the PSC, and further differentiation is neither appropriate nor required.

- (c) The services are included in the AESO's revenue requirement to comply with subsection 3(b) of the *Isolated Generating Units and Customer Choice Regulation*, which requires that the AESO be paid for system access service "as if the isolated community were being provided with system access service via the interconnected electric system." The AESO does not agree that isolated community customers are receiving a subsidy from other customers in respect of system access service. However, subsection 3(a) of the *Regulation* requires the AESO also be paid "the pool price for electric energy they [the isolated community customers] purchase". The isolated community customers are receiving a subsidy from other customers in respect of commodity purchases.

Please refer to the response to Information Request IPCAA.AESO-031 (d) for additional information.

- (d) The AESO understands that choices with respect to service to isolated communities are made by distribution utilities in the context of all factors affecting the provision of electric service, which generally include costs, feasibility, reliability, safety, and environmental considerations, in respect of both current and future loads. Although cost is not the only consideration, where alternatives exist that generally satisfy relevant considerations, the lowest cost alternative is normally chosen. As these communities are currently served through isolated generation, it is reasonable to assume that was the least expensive option if practical alternatives did exist.

Preamble: The AESO states:

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

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

The AESO proposes that all such services be eligible for the Primary Service Credit. Additional discussion, including changes to the Primary Service Credit schedule and associated changes to the customer contribution policy, is provided in section 4.10 of the Application. Beyond the revised Primary Service Credit eligibility criteria, the AESO does not consider it necessary to provide any additional relief for customer interconnections where the TFO does not own conventional transformation facilities.

Reference: Section 4 – 2007 Rate Design, Page 22 of 53.

Request:

- (a) Please confirm that during the stakeholder process the issue of not charging POD level costs for customers who have paid the entire POD cost directly or by reimbursing a TFO for the entire POD cost through a customer contribution was raised.
- (b) Please provide the entire rationale why these customers should be charged anything further for POD level costs if they have already paid for their entire POD cost.
- (c) What objections, if any, would the AESO have to:
 - (i) Providing an exemption in rate DTS for these customers so they do not have to pay POD charges,
 - (ii) Provide that the payment charged to a customer who has paid for their own POD back to that customer rather than to a TFO who has not invested in the asset.

- (d) If the answer to (c)(i) or (ii) above is that the AESO objects to either of these proposals, please provide the rationale for making a payment to a TFO for a service that they have not rendered to a customer.

Response:

- (a) Confirmed.
- (b) When reviewing the issue concerning DTS charges at substations shared with STS services, where the STS customer directly owned customer-related facilities either in whole or in part or had paid a customer contribution in respect of such facilities either in whole or in part, the AESO considered the following factors.
- (i) Certain “customer-related” costs are incurred in respect of a DTS customer regardless of ownership of physical facilities, including but not limited to billing, accounting, customer service, technical and contractual record-keeping, standards, and communications.
 - (ii) Customers may own some, but not all, of the customer-related facilities serving them. For example, a customer may own the substation but not associated radial line, or may own the transformer and low voltage switchgear and buswork but not the high voltage switchgear.
 - (iii) Where a customer has paid a contribution towards the cost of the customer-related facilities, either in whole or in part, ownership remains with the TFO. The TFO therefore incurs ongoing expense relating to operations and maintenance, capital maintenance, and upgrades for those facilities.
 - (iv) Where the TFO owns the customer-related facilities and the STS customer pays a customer contribution towards their cost, the DTS customer usually receives investment towards the DTS share of the customer-related facilities. That investment should be recovered through rates.
 - (v) The DTS customer is paying for system access service, not for specific facilities. System access service through an interconnection to the transmission system provides access to exchange electric energy and ancillary services, and is not differentiated by the actual physical facilities associated with a specific interconnection. DTS customers are charged through average rates for system access service, even though the physical facilities will vary from POD to POD.

Given those considerations, the AESO considers the Primary Service Credit should apply uniformly to all PODs where the TFO does not own transformation facilities. System access service is being provided to the customer, and the customer should pay an appropriate level of costs for that service. The AESO considers that application of the substation fraction, in concert with the Primary Service Credit, provides an appropriate level of charges.

- (c) (i) As discussed in part (b) above, the AESO considers that all customers should pay a POD charge, determined through application of the substation fraction and the Primary Service Credit, as an appropriate share of costs for the service they receive.

- (ii) Also as discussed in part (b) above, crediting a payment back to a customer would not allow recovery of costs incurred with respect to such a POD, on average.

- (d) As discussed in part (a) above, service generally associated with a point of delivery is always provided at some level to the DTS customer, whether by the TFO (operations and maintenance, communications, investment, etc.) or by the AESO (billing, customer service, etc.). The actual quantity of service may vary between customers, but that is also the case for DTS customers at single-service PODs fully owned by TFOs. The nature of a regulated service is that it is provided to customers in accordance with the customer's individual requirements while being recovered through average rates. The AESO continues to consider that the DTS rate, with substation fraction and Primary Service Credit applied, provides an appropriate level of cost recovery from customers who directly own or pay a customer contribution towards all or part of the customer-related facilities through which they receive service.

Preamble: The AESO states:

- (g) XTS will require a minimum contract term of 1 calendar year. The same level of XTS capacity would be contracted for the full contract term, but would be available only in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity.

The AESO had initially proposed that scheduled capacity could be varied on a monthly basis under Rate XTS. On further review, the AESO considers that a uniform amount of capacity should apply for the full contract term. Such a commitment is appropriate when system planning decisions will include consideration of capacity contracted for under Rate XTS, and is comparable to capacity commitments under Rate DTS. However, in recognition of current constraints on ATC, no minimum charge is proposed to apply in hours in which ATC is unavailable for the scheduled capacity, in accordance with point (d) above.

Reference: Section 4 – 2007 Rate Design, Page 47 of 53 .

Request:

- (a) Please explain the rationale for a minimum 1 year term on rate XTS.
- (b) Did the AESO test if there is any support for its design of XTS among potential market participants? If yes, please provide details on this consultation.
- (c) Please confirm that system planners will not be planning additional facilities to accommodate XTS customers given the one year term and the system planning horizon being much longer than one year to initiate a transmission upgrade. If no, please provide details of the transmission infrastructure that will be added to accommodate XTS customer load.
- (d) Please confirm whether it is the AESO's intention to allocate the costs to these XTS customers and then charge a tariff to the XTS customers to recover these costs.

Response:

- (a) The XTS rate is designed to be broadly comparable to the DTS rate, which includes a 5-year minimum contract term. The AESO therefore considers the XTS rate should have a relatively long term, and proposes a 1-year minimum contract term for this first "firm" export rate proposal.
- (b) An XTS rate modeled on the DTS rate was first presented to stakeholders during export and import tariff consultation in the fall of 2005. Stakeholders generally did not oppose the approach.

- (c) Please refer to the response to Information Request PWX.AESO-004 (b). As explained in that response, the requirements of Paragraph 8(1)(g) of the *Transmission Regulation* to restore existing inter-ties to their to original design levels will create additional export capacity. Long-term XTS contracts will be considered when evaluating the need for further inter-tie capacity beyond the restoration of existing inter-ties to original design levels.
- (d) Section 15 of the *Transmission Regulation* applies to enhancements or upgrades that would result in an increase of an existing inter-tie's capacity. Subsection 15(6) of the *Regulation* requires that the cost be paid by those that directly benefit from the enhancements or upgrades. This may include XTS customers, DTS customers, or both, as well as other rate class customers such as DOS and XOS, and will depend on the use described in the needs identification document for the enhancements or upgrades, as approved by the EUB.

Preamble: The AESO states:

However, the AESO continues to support the inclusion of an investment test when assessing the eligibility of an interconnection for the Primary Service Credit. The EUB indicated its agreement with such a principle when it noted in Decision 2005-096 that the PSC “should be related to the avoided average cost of system investment” (p. 38). This principle would be violated if the maximum investment was available for services where “average” facilities were not being provided by the TFO. The AESO therefore proposes that the maximum investment level be reduced by the 40% ratio determined above when conventional transformation equipment is not provided by the TFO, whether through customer ownership of transformation or through unconventional or “virtual” interconnections. This reduction is incorporated in the customer contribution calculation in Article 9.5 of the proposed terms and conditions of service, as discussed in section 6.5 of this Application.

The AESO notes that an additional benefit of reorienting the focus of the investment test is a simplification of the eligibility criteria for the Primary Service Credit. The test no longer involves an estimate of TFO cost for transformation facilities which it will not supply. Eligibility is now determined based on the actual facilities the TFO will provide, with the reduction in investment reflected in the lower maximum investment level applicable when the TFO does not provide conventional transformation.

Reference: Section 4 – 2007 Rate Design, Page 52 of 53 .

Request:

- (a) How does the AESO intend to determine what a TFO considers to be a “conventional transformation” given the wide variations in design of PODs at various locations and configurations on the system?
- (b) Will each TFO develop its own set of standards as to what constitutes a “conventional transformation”?
- (c) Given the complexity of POD design, is it reasonable that it would be a coincidence if the “average” facilities referred to by the AESO above were being provided by the TFO given the wide scatter of actual costs above and below the cost function? Please respond in the context of the cost functions developed by the AESO for substations as a part of the investment policy work.

Response:

- (a) The conditions identified to date where conventional transformation equipment is not provided by the TFO are those listed on page 22 of section 4 of the AESO's 2007 GTA:
- interconnections with customer-owned transformation;
 - interconnections utilizing metering transformers;
 - interconnections which are isolated from the transmission system; and
 - other unusual interconnections such as those taking service at transmission-level voltage without the use of transformation facilities.

Conventional interconnections would be those which utilize power transformers provided by the TFO. The AESO considers the distinctions between unconventional and conventional transformation equipment to be generally recognized in the industry. For example, as discussed in the response to Information Request CG.AESO-009 (a), a metering transformer is typically a small single-phase transformer capable of serving a load of 25 to 100 kVA, and a power transformer is typically a three-phase transformer with a rating of 3 MVA or more. Where it is not clear whether an interconnection should be considered unconventional or conventional, the AESO would review details of the individual interconnection to reach a conclusion, and in doing so would consider similarities between the individual interconnection and existing unconventional and conventional interconnections.

- (b) As discussed in part (a) above, the AESO considers it relatively straightforward to distinguish between unconventional and conventional interconnections and does not expect TFO standards will be needed to support such distinctions. If determining whether an interconnection is unconventional or conventional proves problematic, the AESO would expect, with the involvement of TFOs, to develop interpretation guidelines. As the distinction arises only with respect to the application of the AESO's tariff to an interconnection, the AESO considers that the guidelines should be consistently applied throughout the province and therefore applicable to all TFOs.
- (c) The AESO agrees that the cost of an actual TFO interconnection would frequently not be the same as that calculated through the average cost function. However, the AESO does not consider that actual costs and calculated costs would be the same only as a "coincidence", in the meaning of "by chance". The average cost function was developed through analysis of actual projects and is representative of cost trends of such projects. For example, although there is scatter of actual costs above and below the average cost function, Figure 2 on page 23 of section 6 of the AESO's 2007 GTA illustrates that the costs of several of the analyzed projects were close to the average cost function.

In any case, the average cost function is not meant to be a predictor of interconnection project costs. Project costs are estimated and incurred on a case-by-case basis by the appropriate TFO. The average cost function is instead a means through which:

- an average rate can be developed to fairly, objectively, and equitably recover the POD-related revenue requirement of the AESO from customers, and
- an appropriate maximum investment level can be established which is then recovered through those rates.