
**Alberta Electric System Operator
2007 General Tariff Application
Application No. 1485517**

**AESO Rebuttal Evidence
April 30, 2007**

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Appendix A — Fort McMurray Area Service Requirements Forecast (April 2, 2007)

AESO REBUTTAL EVIDENCE

Evidence was filed in the AESO's 2007 General Tariff Application by:

- Alberta Direct Connect Consumer Association (ADC),
- ATCO Electric (AE),
- Consumers Coalition of Alberta and the Public Institutional Consumers of Alberta (CCA-PICA),
- Dual Use Customers individually (DUC),
- Dual Use Customers jointly with TransCanada Energy (DUC-TCE),
- Industrial Power Consumers Association of Alberta (IPCAA),
- Pipeline Power Group and Associates (PPGA), and
- TransCanada Energy individually (TCE).

The following rebuttal evidence is submitted in response to certain issues raised by interveners. The AESO believes that other issues raised in the intervenor evidence can be adequately addressed by information already on the record or more effectively through cross-examination. Therefore, lack of rebuttal evidence in respect of any issue raised by interveners in their evidence should not be interpreted as agreement on that issue by the AESO.

1.0 DTS Point of Delivery Charge

DUC states that "incremental substation costs above 30 MW should be limited to transformation costs, which increase with size at the much lower rate of about \$10,000 to \$30,000/MW." (DUC POD Charges and PSC Evidence, page 14, lines 9-11) DUC then recommends that "the slope of the cost function above 40 MW should be \$30,000/MW" (page 17, line 12) rather than the AESO's proposed slope above 7.5 MW of \$154,000/MW.

The AESO agrees that the data upon which its proposed cost function was based did not include any projects above 43.2 MW in capacity. The AESO notes, however, that the cost of that project was \$13.5 million, while the AESO's proposed average cost function results in a lower cost of \$11.1 million. This suggests that costs of large projects can be materially higher than the AESO's average cost function.

The AESO has also assessed the reasonableness of the incremental cost component for projects above 30 MW, using a large-project subset of the TFO data discussed on page 24 of the *Customer Contribution Study* filed as Appendix F to the AESO's 2007 GTA. The TFO data included five projects from 46.6 MW to 122.8 MW interconnected within the past 20 years. The data for these five projects is summarized below from the attachment to Information Response PPGA.AESO-007 (a).

Substation	Year	DTS Capacity (MW)	Original Cost (\$ 000 000)	2007 Cost (\$ 000 000)
365S	1991	46.6	\$3.26	\$4.65
308S	1990	56.8	\$7.59	\$11.44
484S	1988	81.6	\$5.59	\$9.28

332S	1999	95.2	\$7.99	\$9.89
122S	1990	122.8	\$10.12	\$15.25

A simple linear regression analysis of these five projects provides the following average cost function:

5 Average Large TFO Project Cost = \$2.151 million + (\$0.099 million/MW × DTS Capacity)

The correlation coefficient for the above projects and cost function is $R^2 = 0.616$, which is a relatively high value but based on a very small data set.

10 The large TFO project cost function has an incremental component of \$99,000/MW, which is over three times as high as DUC's recommended \$30,000/MW. The AESO suggests that, based on the limited data available, the AESO's proposed cost function remains more appropriate for large projects than DUC's proposed function.

15 The AESO also notes that PPGA proposes a POD charge that includes a final incremental rate component of \$1,024/MW (PPGA Evidence, page 17). Although PPGA does not provide a cost function that corresponds to its POD charge, the final incremental rate component is about 32% higher than the AESO's proposed final component of \$776/MW. This indicates that PPGA's corresponding cost function would include \$203,000/MW as the
20 final incremental component, which is significantly higher than both the AESO's similar component and the incremental cost indicated by the above analysis.

25 In its Evidence and in its responses to DUC.PPGA-1 and -2, PPGA provides its views on why the POD cost function data and analysis presented in the AESO's Application is appropriate for development of the maximum investment function but not for development of the DTS POD charge. For example, in DUC.PPGA-1, page 1, PPGA states:

30 The PPGA believes that the AESO's investment function supports the directive from the Board. The PPGA does not believe that the Board intended to use the investment function to determine the POD charge.

The AESO submits the EUB made it clear throughout Decision 2005-096 that costs should underlie both the development of the investment function and the design of rates. Specifically, in Decision 2005-096 the EUB stated:

35 *To conclude, with regard to the rate design principles discussed above, 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. (page 17)*

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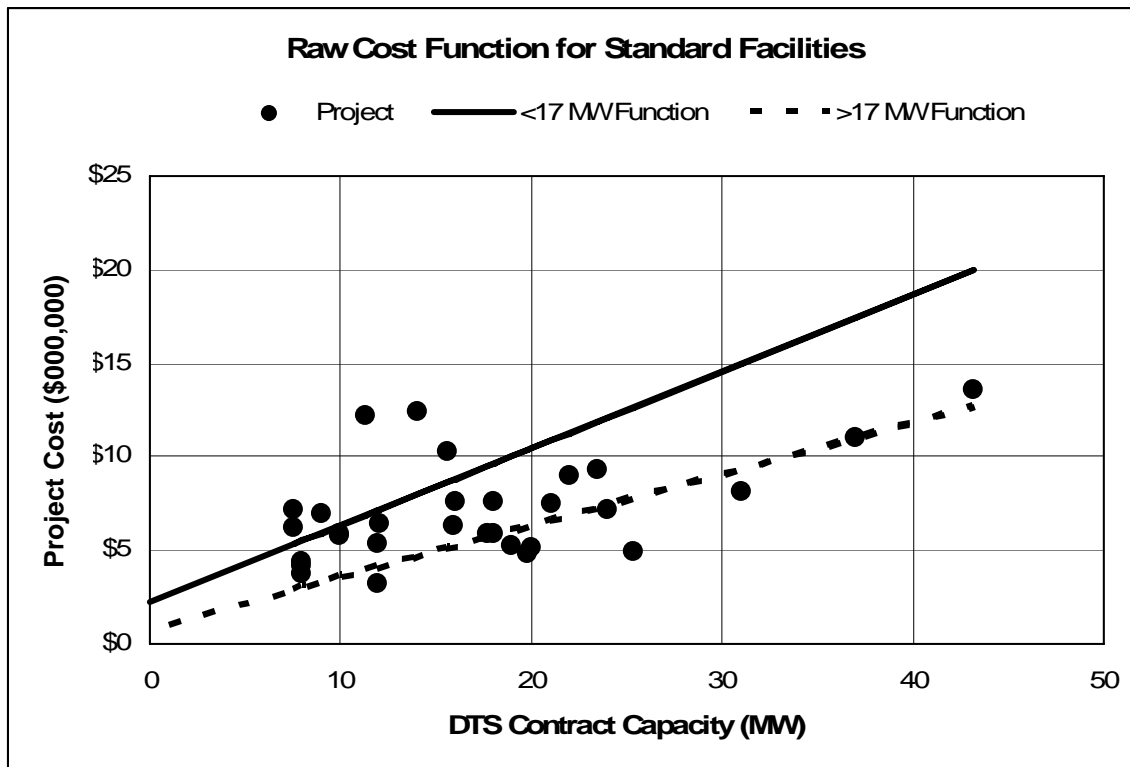
5 *The Board considers that unbundling, as recommended in the TCCS report, would allow for rates that are more reflective of cost causation, more visible and capable of sending more appropriate price signals to customers.*
(page 26)

10 *The Board has noted in the previous section on rate design principles that it considers cost causation to be the most important principle and the Board is in agreement with ADC and IPCAA that rates should reflect this principle to the greatest extent possible.* (page 27)

...the Board has determined that cost, not revenue, is the appropriate starting point for establishing the investment policy. (page 56)

15 PPGA further suggests (PPGA Evidence, page 17, and DUC.PPGA-1) that regression analysis at different DTS MW “breakpoints” such as 15 MW, 17 MW, and 20 MW provides much higher correlation coefficients than the analysis filed by the AESO, and should therefore form the basis of the maximum investment function. Although PPGA does not provide a cost function that corresponds to its proposed POD charge, the AESO has
20 examined the correlation analysis prepared by PPGA and believes that it exhibits the same issues discovered during the development of the AESO’s proposed cost function. The AESO examined a number of possible linear and non-linear functions, different capacity thresholds, breakpoints, and regression analysis techniques during the development of its proposal. Many of these were discussed and modified over the course of the stakeholder
25 consultation.

The following chart illustrates a specific concern with the approach proposed by PPGA.



The chart shows two raw cost functions for projects less than and greater than 17 MW of DTS contract capacity. The concern is that the two functions are nearly parallel, and do not intersect for positive contract capacities. If both functions are to be utilized, there must either be a discontinuity in the function or artificial manipulation of one or both functions to avoid such a discontinuity. Similar results were found at other breakpoints.

In this case, the coefficient for the large project cost function is $R^2 = 0.68$, the coefficient for the small project cost function is $R^2 = 0.21$.

Finally, in Information Response DUC.PPGA-1(a), PPGA states (page 4):

A key factor in assessing the adequacy of the AESO's analysis is the level of R^2 . In PPGA.AESO-005, the AESO highlights the definition of R^2 and its use. In its response, the AESO acknowledges that the level of R^2 is not as important as its use. The AESO concludes that despite several shortcomings, that data is sufficient in "determining a cost function to be used as the basis for the maximum investment function for the AESO's tariff". Again, the PPGA is supportive of the AESO's response; in the determination of the investment function, the R^2 result from this analysis is adequate. However, the AESO does not propose that this level of analysis is sufficient justification for such a dramatic differentiation in DTS and POD rates.

PPGA's last sentence is incorrect. The AESO has submitted that the data and resulting analysis in the *Customer Contribution Study* is sufficient for development of the maximum investment function and for the transmission point of delivery cost classification and POD charge. The AESO specifically stated on page 13 of section 4 of its Application:

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While discussing the AESO's maximum investment formula in Decision 2005-096, the EUB determined "that cost...is the appropriate starting point for establishing the investment policy." (p. 56) The EUB ultimately directed and approved an investment policy derived from the point of delivery cost information included in the Transmission Cost Causation Study. However, in Direction 13A the EUB also required the AESO to analyze additional data to recommend a maximum investment function, as provided in section 6 of this Application.

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The same costs (essentially those comprising the point of delivery function) ultimately underlie both the DTS POD charge and the AESO investment function. The AESO therefore developed both aspects of its tariff together, and relied primarily on the detailed examination of the point of delivery cost data conducted during development of the maximum investment function.

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PPGA also states on page 4 of its response to DUC.PPGA-1 (a):

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The AESO concludes that the original cost causation study is inadequate, and drew unclear POD results, but somehow the Greenfield POD analysis is representative of this original study. The PPGA believes that this conclusion reached by the AESO in this case is confusing, inadequate and unsupported.

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This is also incorrect. On page 13 of section 4 of its Application, the AESO states that the data from the *Transmission Cost Causation Study* also exhibited significant scatter and did not contain the same level of project cost detail as was available in the *Customer Contribution Study*. The AESO therefore determined that it was reasonable to use the most accurate cost information available in the determination of the POD charge, namely, the data from the *Customer Contribution Study*.

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2.0 Backup or Standby Service

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DUC-TCE provide a backup rate proposal, which it states (DUC-TCE Standby Rate Evidence, Appendix 1, page 28) "should collect adequate revenue to recover the cost of providing the service". However, when replying to information requests relating to "the cost of providing the service", DUC-TCE appears to primarily rely on comments provided by the AESO during consultation for its 2007 GTA:

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- DUC-TCE Evidence, page 4, line 15: "The AESO stated that the proposed June 2006 BTS rate was cost based...."

- DUC-TCE Evidence, page 5, line 27: “The AESO has demonstrated that standby usage results in lower system costs....”
- 5 • DUC-TCE Evidence, page 11, lines 18-20: “The energy charges for Uncontracted Energy, which sum to over \$29/MWh, were derived to meet the AESO proposed rate design of customer price neutrality at a 10% Uncontracted Load Factor.”
- 10 • DUC-TCE Evidence, page 36, lines 26-27: “The AESO also further confirmed that Standby Services generally do not drive costs on the transmission system....”
- 15 • DUC-TCE Evidence, page 37, lines 24-26: “Again the AESO confirmed that Backup Service customers (short duration, infrequent use) would generally not affect either long-term or short-term planning decisions or give rise to long-term or short-term costs on the transmission system.”
- 20 • IR AESO-DUC/TCE-2 (a): “The proposed standby rate is intended to collect an appropriate level of revenue to recover the costs imposed by dual-use customers for the provision of Standby Services. It is our understanding that the AESO’s proposed BTS rate design had the same objective.”
- 25 • IR AESO-DUC/TCE-9: “As well, the AESO proposed DTS over-collects revenue based on AESO’s own cost causation analysis.”
- IR BR-DUC/TCE-8: “Ex. 236 at Appendix 2, pages 36 and 37, was intended to reflect the fact that the AESO has stated that BTS customers would not drive short or long term planning decisions.” (emphasis in original)
- 30 • IR CG-DUC/TCE-6 (a): “The DUC relied on the AESO’s draft Backup Transmission Service (BTS) that suggested a 10% indifference point.”
- IR CG-DUC/TCE-6 (b): “We also assume that the AESO took the principle of cost causation and its other rate design principles into account before it proposed a 10% indifference point.”

35 The following clarifies some aspects of the AESO’s backup service analysis and how the proposed DTS rate was developed. The AESO agrees that during its consultation for the 2007 Tariff it stated that backup service would impose minimal costs on the transmission system. As summarized on page 33 of section 4 of the 2007 Application, “Initial consideration suggested minimal costs are caused by short-duration, infrequent use of the transmission system.” However, this was not the AESO’s final conclusion. The AESO continued to analyze backup service and related costs, conducted further consultation and investigation, and determined that its initial assessment was incorrect.

45 If DUC-TCE chooses to rely on the AESO’s evidence to assess costs caused by backup use, it is the AESO’s final evidence that must be relied on, not a preliminary approach developed prior to the finalization of the analysis and proposal.

As detailed in section 4.6.2 of the Application, the AESO concluded that the accommodation of backup load on the transmission system is responsible for greater costs than initially suggested. Transmission planning has historically accommodated a degree of backup load as part of the load on the transmission system. Specific recent projects have more specifically quantified the backup load accommodated.

In particular, DUC-TCE itself refers to a recent update of the Northeast Alberta service requirements originally referred to on page 37 of section 4 of the Application. The Fort McMurray Area Service Requirements Forecast, dated April 2, 2007, was referenced in BR-DUC/TCE-1 (a) and is provided as Appendix A to this rebuttal evidence. The following information is included in that Forecast:

2016 Forecast	Load Forecast		Transfer Capability		Capability/Load
High Load Factor DTS	851 MW ⁽¹⁾	42%	851 MW	50%	100%
Low Load Factor DTS	1,187 MW ⁽²⁾	58%	849 MW	50%	72%
Total DTS	2,038 MW ⁽³⁾	100%	1,700 MW ⁽⁴⁾	100%	83%

Sources:

- (1) Page 25 of April 2 Forecast
- (2) Page 21 of April 2 Forecast
- (3) Sum of (1) and (2) as referenced on page 36 of April 2 Forecast
- (4) Page 36 of April 2 Forecast

The load forecast of 2,038 MW represents the DTS load megawatts which are forecast to be interconnected in the Fort McMurray area in 2016, and comprise 851 MW of high load factor “normal” load and 1,187 MW of low load factor backup or standby load. The 2,038 MW represents the maximum billing capacity that could arise from these loads under both the current and proposed definition of billing capacity in the AESO’s DTS rate.

The transfer capability represents the actual DTS capacity for which the transmission system in the Fort McMurray area is being designed, based on the approach documented in the April 2 Forecast. The total is 1,700 MW, which is less than the total interconnected DTS loads due primarily to diversity of the low load factor DTS loads. A conservative assumption is that 851 MW of transfer capability accommodates the 851 MW of high load factor DTS loads, with the balance of 849 MW of transfer capability accommodating the low load factor DTS loads with forecast diversity. This assumption is considered conservative because it assumes all high load factor DTS loads are coincident on the transmission system. Any diversity of the high load factor DTS loads would lower the transfer capability attributed to these loads, and accordingly increase the remaining transfer capability attributed to low load factor DTS loads.

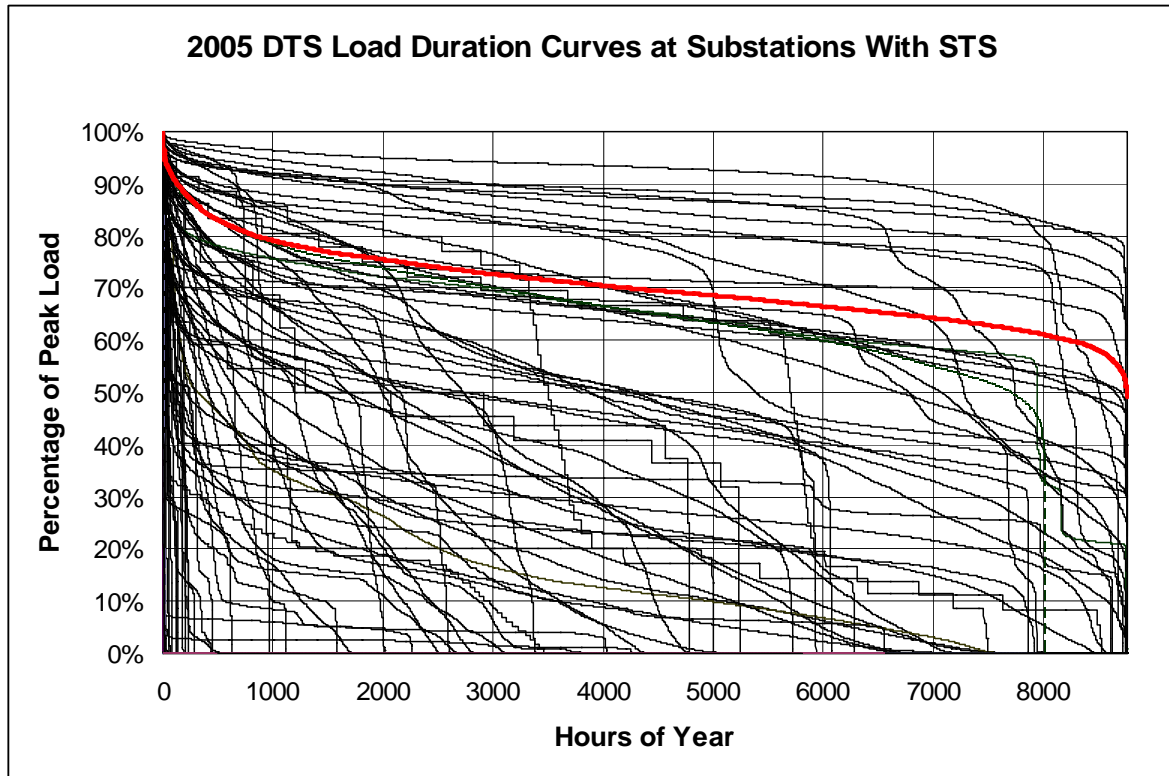
From the table above, 1 MW of interconnected high load factor DTS load “causes” 1 MW of transfer capability, while 1 MW of interconnected low load factor DTS load “causes” 0.72 MW of transfer capability. The Fort McMurray Area transmission system is being planned to provide the total transfer capability of 1,700 MW. It is therefore reasonable to

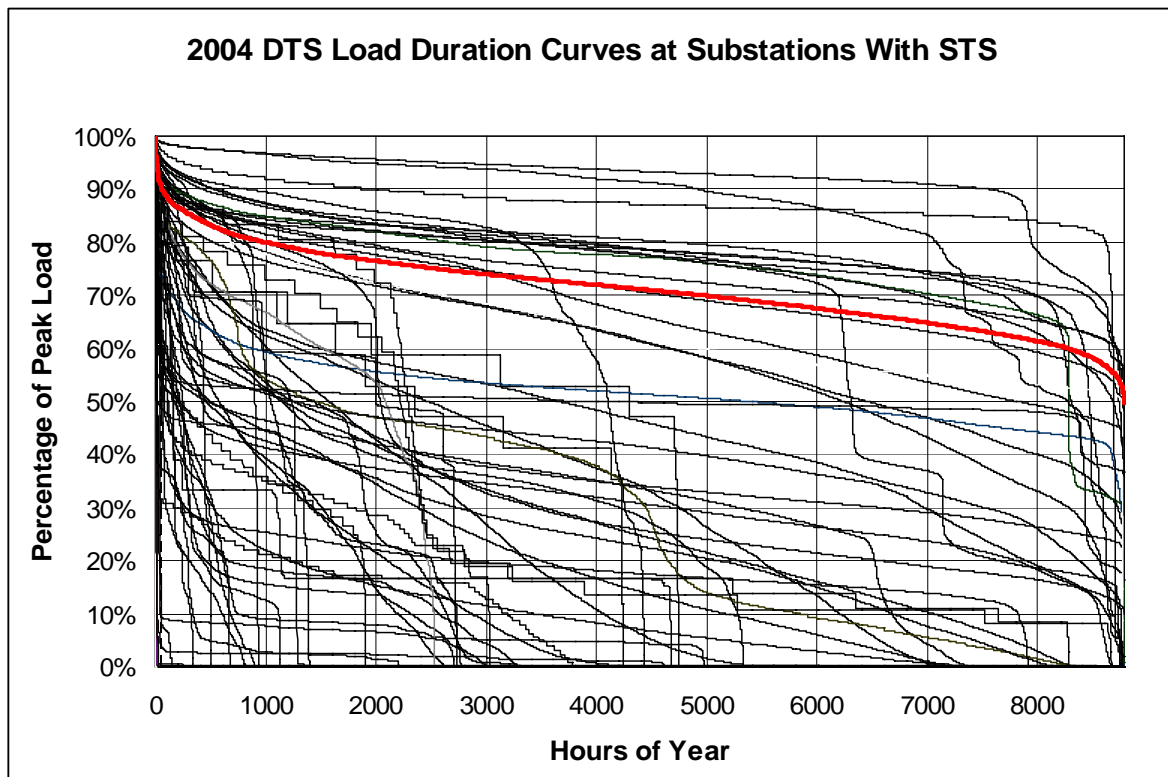


5 conclude that for every \$1.00 of cost responsibility per MW of billing capacity for a high load factor DTS load, there should be \$0.72 of cost responsibility per MW of billing capacity for a low load factor DTS load. In the terminology used on page 37 of section 4 of the AESO's Application, a megawatt of backup load should be allocated 72% of the amount that would be charged to a megawatt of normal load, based on the Fort McMurray Area Service Requirements Forecast of April 2.

10 The AESO notes that this amount is significantly greater than the 45% of "normal" load charges that would be paid for a backup service under the AESO's proposed DTS rate. The AESO considers that the analysis originally presented in its Application remains reasonable and indicative of costs that should be attributed to backup and standby loads. The Fort McMurray Area development will include the greatest concentration of backup service in Alberta in the foreseeable future, and will likely not be representative of the transmission system as a whole. However, the analysis provided above demonstrates that the AESO's
15 proposed allocation of costs to backup service is not excessive for the Fort McMurray Area and that recovering a portion of these on a demand basis is also appropriate. The even lower allocation of costs to backup service proposed by DUC-TCE would clearly under-allocate costs to backup service in the Fort McMurray area.

20 DUC-TCE and IPCAA each include load duration curves for theoretical backup services (DUC-TCE Standby Rate Evidence, page 16, Figure 1 and Evidence of Drazen Consulting Group on Behalf of IPCAA, page 11). Although hourly metered energy data for individual customers is confidential information, the AESO has reviewed actual data for the DTS loads at substations with STS contracts discussed in information response IPCAA.AESO-047 (b-c)
25 Revised. The following load duration curves for 2005 and 2004 are based on actual hourly metered energy for the DTS loads at substations with STS contracts.





The thin black lines in these graphs represent values for individual DTS loads interconnected at substations which also serve one or more STS customers, while the thick red lines represent the aggregate hourly data for all such DTS loads. The data on which the thick red lines are based was provided in the schedules attached to Information Response IPCAA.AESO-047 (c) Revised. From these two graphs, the AESO makes the following observations:

- (a) Backup loads do not exhibit uniform or consistent usage patterns, and in particular do not exhibit distinct and similar usage below or above any particular load factor threshold.
- (b) The existence of a generator in conjunction with a DTS load also does not appear to result in a uniform or consistent usage pattern.

Accordingly, the AESO concludes there does not appear to be support for a separate rate class based on a load factor threshold. Rather, the load duration curves for these DTS loads at substations which also serve one or more STS customers suggest an appropriate rate should accommodate a variety of usage patterns over a wide and near-continuous range of load factors. The AESO's proposed DTS rate accommodates such variety with no explicit thresholds or discontinuities.

3.0 AESO Standard Facilities

As indicated in AE's Evidence, the AESO is engaged in an on-going dialogue with its customers, including AE, on the AESO's interpretation of Standard Facilities. This dialogue falls under the umbrella of the AESO's current activities aimed at addressing the Board's Harmonization Directive (Decision 2005-096, page 73).

Specifically, the AESO has initiated activities in this regard as follows:

(1) A "Policy Clarification on Standard Facilities" document was drafted in March 2007, and is discussed below; and

(2) A meeting to discuss the Harmonization Directive with customers has been arranged for May 9, 2007.

The purpose of the AESO's Policy Clarification on Standard Facilities is to provide customers with a clear, concise statement concerning the meaning of "least cost" in the context of the AESO Tariff definition of Standard Facilities. This draft policy was shared verbally with representatives of AE on March 6, 2007 and, when applied to AE's Updike Project, seemed to the AESO to address their concern.

The AESO's Tariff defines Standard Facilities as:

"AESO Standard Facilities" mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection.

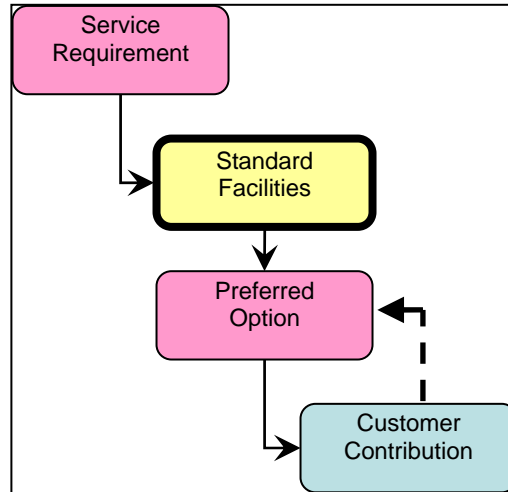
The policy clarification document states that the AESO has two distinct roles in responding to each Distribution Facility Owner (DFO) Point of Connection (POC) request:

(1) Determine the Standard Facilities through a technical and economic evaluation; and

(2) Apply the Customer Contribution Policy.

To begin the process, as shown in the figure below, the DFO makes a request for service. The POC request undergoes a technical evaluation to determine one or more viable alternatives. The AESO then has to identify the Standard Facilities through an economic evaluation of the viable alternatives. The customer then selects the "preferred option" (which can be either the Standard Facilities or some other facilities that meet their needs), and the AESO's Customer Contribution Policy (AESO Tariff, Article 9) is applied.

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The AESO’s transmission planning team, including an economic analyst, identifies the Standard Facilities using the AESO’s *Distribution POD Interconnection Process Guideline – Economic Evaluation* (the “*Guideline*” as can be found on the AESO website). The *Guideline* outlines, “the recommended approach to economic evaluation of the alternatives for AIES interconnection projects” (*Guideline*, page 1).

The objective of the economic evaluation is, “to determine the relative economics of viable alternatives considering both the transmission and distribution supply options. It is assumed that only those alternatives that meet the basic system performance criteria will be evaluated” (*Guideline*, page 3).

The *Guideline* was developed for use by both the AESO and DFOs. It provides the following methodology for evaluating the economics of alternatives (*Guideline*, page 3):

- The cost analysis shall be based on either the NPV of the revenue requirement of the alternatives, or on the NPV of the capital and operating expenses of the alternatives.
- For multi-year projects the AFUDC shall be included in the evaluation. The weighted cost of capital as noted in Section 3.1 shall be used.
- The study period shall be consistent with the life of the proposed projects.
- The discount rate to be used in this analysis shall be calculated in accordance with Section 3.1.
- Assumptions and forecasts such as those related to pool price, cost escalation etc. shall be stated explicitly and rationalized.

- Sensitivity analysis relating to capital cost estimates, escalation factors etc. shall be carried out when the net present value of the alternatives are similar.
- 5 • To the extent possible, all the factors shown in Section 3.0 are to be included. These are:
 - Cost of Capital and Discount Rate
 - Capital Cost and Depreciation
 - Operation and Maintenance Costs
 - 10 ○ Cost of Losses (both T and D)
 - Insurance and Property Tax
 - Salvage and Early Retirement
 - Cost Escalation

15 Although the *Guideline* is used for the purpose of evaluating alternatives, and identifying the Standard Facilities, it also clearly states that (*Guideline*, page 1):

20 The intent of this guideline is to present a consistent methodology of evaluation of interconnection alternatives that result in cost effective solutions for the customers.

25 This guideline is intended solely for the purpose of supporting the AESO's customer interconnection process to arrive at proposed interconnection concepts that are optimized on a technical and economic basis. It will not in any way address or determine the AESO's facility cost allocation between system and customer, nor will it be used in any way as a guideline in applying the AESO approved tariffs and investment policy. [Emphasis added]

30 Therefore the "least cost" option should be understood to be the option that has the lowest economic costs when all such costs, as outlined in the *Guideline*, are considered.

35 Once the Technical Evaluation is completed to the AESO's satisfaction, the DFO can decide whether it wants to pursue the Standard Facility or one of the other viable alternatives (the DFO usually identifies a Preferred Option, as shown in the figure above).

40 The AESO Project Manager, in conjunction with support from AESO Regulatory staff, can then proceed with the application of the Customer Contribution Policy (AESO Tariff, Article 9). This section of the AESO Tariff determines the amount the DFO must pay (if any) in order to proceed with their preferred option.

45 Although the application of the Customer Contribution Policy is a separate part of the AESO's response to a DFO POC Request, it should be noted that in Article 9.1 (b) of the AESO's 2006 Tariff, the phrase "the most economic option" refers specifically to the Standard Facilities.

In accordance with AE's evidence, the following example is provided to enhance the clarity of the AESO's position on Standard Facilities. In the example, it is assumed that:

- (1) All options are viable, meeting all of the AESO's transmission planning criteria;
- (2) The information and analysis provided to the AESO is both complete and in a form acceptable to the AESO; and
- (3) The economic evaluation is accurate and adheres to the *Guideline's* principles.

Example 1: Updike 144 kV Line and Substation (direct evidence of AE, pages 3-9)

Based on AE's original submission and information available at that time, the AESO directed AE to file a facilities application for this project in May, 2006 with the Standard Facilities assessed as the addition of a regulator and upgrades to the existing transformer (addition of fans) at the Goodfare Substation. These Standard Facilities were estimated to cost \$1,096,000 and formed the basis for the AESO investment level. (This Standard Facility is different from AE's preferred option). Subsequently, AE brought forward a revised proposal that included a new load forecast and a more detailed economic analysis which the AESO is presently reviewing. The alternatives being reviewed are as per AE's evidence and are as follows:

Option	Capital Costs		Losses (kW)	Losses (\$)	TOTAL (NPV)
	Transmission	Distribution			
Alternative 1: Add a 2 nd Transformer at Goodfare substation	\$2.5	\$0	D - 2,370 @ peak	\$9.3	\$12.3
Alternative 2: New POD: Updike substation and line	\$8.4	\$0	T - 71 @ peak	\$0.3	\$10.3

Note: all \$ amounts are expressed in millions

Based on the current information as tabulated above, the Standard Facility would be Alternative 2. AE and the AESO are continuing to work together to finalize the outcome for this project.

To summarize, for any DFO POC request, the term "least cost" refers to the option that has lowest total dollar value when all reasonable capital costs, operating costs, and losses (both T and D) are taken into consideration. To be acceptable, the supporting economic analysis must follow the AESO's *Guideline*.

The AESO submits the determination of Standard Facilities (in accordance with the AESO's Policy Clarification on Standard Facilities) sends the appropriate economic signal in support of proper transmission planning practices that support the best long-term interests of the AIES.

The PPGA, in its Transmission vs. Distribution evidence (page 6), requests:

...that the EUB clarify and direct the AESO in the following:

- The current guidelines regarding the flicker limit test should be restated such that the test is conducted on a three times in-rush basis – to ensure that the test is fair and that customers are not directed to implement an AESO initiated VFD to accommodate motor starting.

The purpose of implementing flicker limit standards is to ensure that the flicker caused by one customer does not unduly affect another customer. To manage this, the AESO has a clear policy in regards to flicker limits for the transmission system which is contained in the AESO's "Generation and Load Interconnection Standard". This standard clearly states that the applicable standard to be used for this assessment is the IEC Standard 1000-3-7 "Electromagnetic Compatibility (EMC)-Part 3:Limits-Section 7:Assessment for emission limits fro fluctuating loads in MV and HV power systems". This standard is an industry accepted standard and is further adopted by the Canadian Standards Association in the standard CAN/CSA-C61000. Of further note, the flicker limits on the distribution system are set by the Distribution Facilities Owners (DFOs) and not the AESO. The DFO's have based their flicker limits on standard. IEEE 519 or CAN/CSA – C61000. In some circumstances, local conditions on a distribution feeder may cause the DFO to apply more stringent measures. To direct the AESO and/or DFO's to follow any other methodology would be contrary to industry practice.

In regards to the comments with respect to T vs. D decisions in the PPGA Executive Summary on page 2, please refer to the AESO's rebuttal to AE's evidence on Standard Facilities above. It should be noted that the AESO's determination of Standard Facilities is used to assist the AESO with decisions on customer contribution levels, and does not limit the customer in selecting whether he/she should select a transmission or distribution option. This selection is left completely up to the customer who is in the best position to assess the level of service that is required.