



Customer Contribution Study

AESO 2007 GTA
Terms and Conditions
Consultation

November 3, 2006

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Introduction

The AESO proposed a number of changes to the Customer Contribution Policy as part of its 2005-2006 GTA. Following extensive discussion during the hearing, EUB Decision 2005-096 directed the AESO to make a number of revisions to Article 9 of the AESO's terms and conditions.

In its decision, the EUB stated that the maximum investment function proposed by the AESO was "overly simple. As a result, it does not achieve an appropriate balance between simplicity and appropriate economic signals." The EUB's concern was that the AESO proposal placed an emphasis on revenues as a function of the Customer Contribution, whereas the EUB considered that cost was the appropriate starting point for establishing the investment policy. As such in Direction 13 the AESO was directed to adjust the investment levels to reflect the following:

- *A minimum investment allowance of \$2.5 million, and*
- *An additional investment of \$100,000 per MW of project capacity.*

Assuming a maximum 20 year contract term, the AESO refiled Article 9 with investment levels of \$125,000/year of contract term plus \$5,000/MW/year of contract term.

In Decision 2005-096 the EUB also directed the AESO to conduct additional work on the Customer Contribution Policy and report back to the EUB with its results for the AESO's 2008 GTA:

13A. In respect of the longer term beyond 2006, the Board directs the AESO to conduct further study so that it may devise a more comprehensive investment function proposal which avoids the Board's concerns with the AESO's 2006 Application and reflects the design principles described by the Board in this Decision. The Board considers that this task will involve several distinct steps, as reflected in the following list of Board directions:

- 1. The Board hereby directs the AESO to conduct a study for the purpose of devising a simplified maximum investment function. Such study to be completed in time for review no later than the 2008 GTA proceeding. The study should incorporate a sufficient number and diversity of data points to enable the study to consider the current costs of several different interconnection project sizes. Interconnection project costs for the purposes of the investment function study should only reflect the costs of standard facilities as described in the AESO Standard Facilities definition approved by the Board in this decision.*

2. *On the basis of the results of the study described in the preceding direction, the AESO shall recommend an investment function that represents the average cost per MW of capacity. The Board expects that the resulting interconnection cost function derived will exhibit significant economies of scale and, as a result, may be non-linear in nature. For the purposes of the remaining steps of the Board's maximum investment function directions, the average cost function derived in accordance with this step will be referred to as the "Raw Interconnection Project Cost Function".*
3. *In accordance with the notion of a tolerance as discussed in the argument of IPCAA, the Board directs the AESO to analyze the results of the above study for the purposes of determining an appropriate multiplier such that approximately 80% of the projects included have a cost greater than implied by the Raw Interconnection Project Cost Function fall within the selected tolerance multiplier.*

The Board directs the AESO to present the results of the above analysis for review no later than the time of filing its 2008 GTA, along with its proposal for an appropriate maximum investment formula. [p. 58]"

Prior to re-filing the responses to the directions outlined by the EUB in Decision 2005-096, the AESO conducted a pre-filing stakeholder session to discuss the investment level as outlined in Direction 13. The AESO presented analysis that suggested that the investment levels as identified in Direction 13 resulted in significantly higher contributions than the AESO's previously approved investment policy.

All documents relating to these customer consultations can be accessed on the AESO's website by following the paths:

- Tariff ► Current Consultation ► 2007 Terms and Conditions, and
- Tariff ► Previous Applications ► 2005-2006 Tariff Refiling.

Issues

In responding to Direction 13A the AESO intends to address the following issues raised by parties:

- The 2006 approved investment levels appear to be significantly lower than the previous AESO investment policy.
- Concerns were expressed with the sample data provided by the AESO, including, for example, lack of thorough analysis of the data, definition consistency with rate design, and unexplained anomalies in the data.
- Potential intergenerational equity concerns were raised.
- Some participants questioned whether the target 80% of projects being covered by investment is determined based on the number of projects or the dollar value of projects.
- The combined effects of high transmission development costs, a reduction in investment levels, and increased number of projects required to pay a contribution create a barrier to new industrial load development.
- The contribution policy needs to balance previously stated customer contribution principles and the evolution of the Alberta electric industry.

The AESO produced Terms of Reference for the Customer Contribution Study, which proposed to address these issues. Stakeholders provided input on the Terms of Reference, and a revised document was issued on February 28, 2006. The remainder of this paper reflects these final Terms of Reference.

Scope

The three components as outlined in Direction 13A will be the basis for the scope of this study. During the course of the study, the AESO will:

1. Incorporate a sufficient number and diversity of data points

The proposed approach entailed the gathering of data for the most recently constructed substations for which the AESO has information (i.e. for the years 2000 to 2006) and deconstructing the project and cost information. The cost information was sorted into various categories.

As per the Terms of Reference, the AESO also committed to consider additional information during the course of the customer contribution study. A number of variables were analyzed throughout the course of the study.

The deconstructed project information will align with the definition of Point of Delivery (POD) as utilized in the AESO's rate design and project costs will be updated to current dollars.

The AESO also undertook to compare and test the data collected with projects that are expected to be constructed in the near future or are complete and awaiting final reconciled cost information.

2. Determine the Raw Interconnection Project Cost Function

The AESO collected data as outlined above and analyzed the results in order to determine the Raw Interconnection Project Cost Function. The intent was to recommend an investment function that represents the average cost per MW of capacity but further analysis investigated whether the data exhibited any significant economies of scale, if the relationship between contract capacity and cost was linear or non-linear in nature or if relationships other than contract capacity and cost existed.

3. Determine an appropriate multiplier such that 80% of projects do not pay a contribution.

The raw data was examined for indications of relationships in order to determine a Raw Interconnection Project Cost Function. The proposed function would then be investigated using different multipliers to achieve an investment where 80% of projects do not pay a contribution.

The Final Customer Contribution Study Analysis

The preliminary results of the Customer Contribution Study addressed the first two components of the study, as outlined in Direction 13A. The third component of the study, the proposal of a "multiplier" that will be applied to the cost function so that 80% of projects do not pay a contribution, will be addressed in these final results of the study.

Methodology Overview

Availability of data

The preliminary analysis component of the study envisioned utilizing historical data to determine the individual cost components that form the basis of substation construction costs. This information primarily relied on final cost data submitted by TFOs. Where final reconciled costs or their allocations were unavailable, every effort was made to allocate final actual costs based on estimate information using Proposal to Provide Service (“PPS”) documents or Order of Magnitude documents.

The data was drawn from AESO maintained databases – CASPIR (Customer Access Services Project Information Resource) and TASM0 (Transmission Model Database). In addition, project information was extracted from internal Customer Contribution determinations and other project information documentation.

Where limited cost information was available, the project was excluded from the study.

Project and Category Classification

The AESO identifies each connection proposal as a “Project” and assigns project identifications on a numerical basis. Currently, the AESO information systems track more than 500 projects from inception to completion.

All project information is maintained both electronically and in hard copy, in numerically ordered project files. Project files are filed by their assigned number.

A single project to interconnect a customer may involve more than the construction of a substation. It may also involve upgrades to adjacent substations, transmission lines, etc. Analysis of complete projects indicated that some projects involved the construction of more than one substation. In these cases, each substation was deconstructed, based on information availability, so that project numbers have appeared twice identifying different substation names. This is the case for Project #10 (involving the construction of Algar and Mariana substations) and Project # 79 (involving the construction of Crow and Gregoire substations). For these two projects, an attempt was made to isolate just those costs associated with the identified substation. For the balance of the projects, total project costs were identified.

The classification of system and customer-related costs is as outlined in Article 9 of the AESO’s Terms and Conditions. When project costs are determined, the AESO allocates these costs to the system or the customer, based on the nature of the project. For POD customers, customer-related costs are the costs associated with the construction project, entailing radial transmission extensions and enhancements at adjacent substations. These costs can normally include the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer’s interconnection.

System-related costs are those project costs associated with looped transmission facilities, radial transmission lines that will become looped within five years, or in any circumstance where the AESO deems that for economics or system planning purposes a facility larger than that required to serve the customer is necessary. In those cases, the AESO classifies these portions of the project as system-related costs.

Customer-related costs are those costs that the customer is responsible for, and include standard facility costs and those costs that are deemed in excess of standard facility costs. AESO standard facilities are the least-cost interconnection facilities which meet good transmission practice, including reliability, protection and operating criteria and standards. These generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection. Standard Facility costs are the only costs eligible for investment under the AESO Tariff.

Excess of standard facility costs are those costs that are in excess of the AESO deemed standard facility interconnection configurations. For example, “acceleration” payments are deemed in excess of standard costs, and customer preferences to construct premises that are larger or provide more capacity than is deemed necessary by the AESO are in excess of standard facility costs. The customer is responsible for paying all customer costs in excess of AESO standard facility costs, and these costs are not eligible for AESO investment.

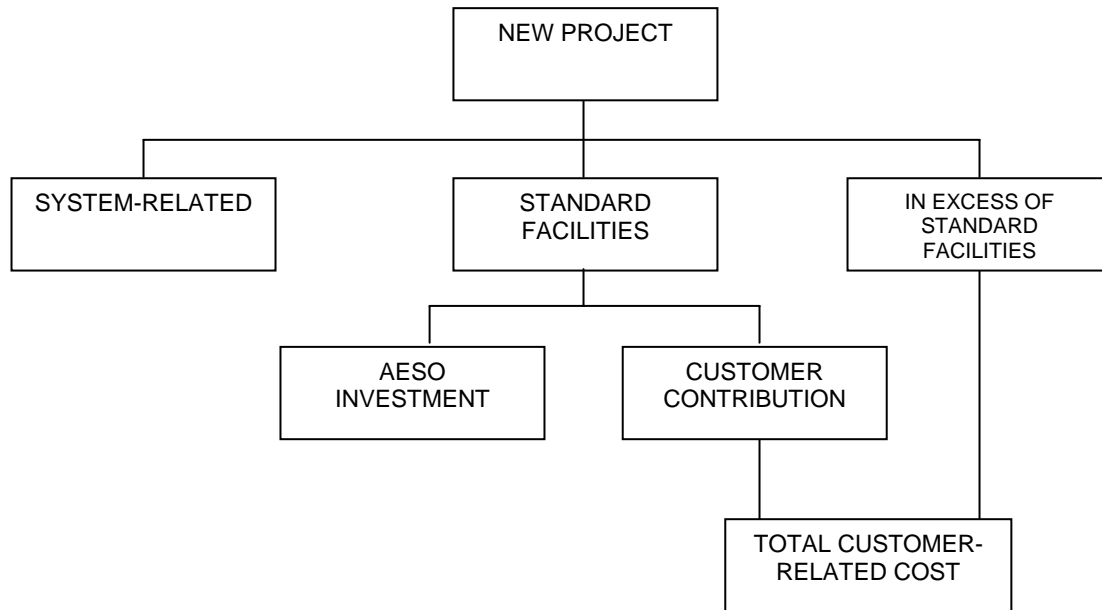
Total substation costs are those costs distinctly associated with substation construction, including labour. Transmission line construction, and work performed at adjacent substations in respect to the project would not be included in substation costs. Transformer and breaker costs are strictly material costs, and do not include the labour involved to construct and install the items. Where total substation costs were available, but transformer and breaker costs were not identified, an estimate was used for transformer and breaker costs (Blackmud 155S, Edmonton 216S, Marlboro 348S and Carvel 432S). These standard estimates were gathered by the AESO in 2004 for an unrelated project, and present value multipliers were applied.

Total project costs include all costs associated with a project, which form the basis of customer contribution investment calculations. Substation equipment, protection, SCADA and transmission line costs are strictly material costs and all labour costs are included in the labour category.

Two substations in the sample (Yasa 332S and Ellis 286S) were constructed and subsequently totalized with existing substations, having the effect of increased DTS contract capacities associated with the POD. DTS contract capacities in these cases were allocated to the increase in load that was attributable to the substation being analyzed.

Figure 1 demonstrates the cost determination process for new projects.

Figure 1



Collected Information

The following information was collected for each project as part of the preliminary analysis:

Table 1

Information	Source
Facility/Substation Information	
Project Number	Projects are assigned numbers upon receipt of a proposal.
Substation Name, ID	Substations are assigned names (TASMo)
Facility (Substation) Code	Substations are assigned codes (TASMo)
Year	The year in which the PPS was issued, or as recorded in cost estimation data.
DTS Contract Capacity	As per DTS contract agreement, information obtained from Settlements systems
Physical Aspects of PODs	
Voltage	TASMo
Single or Multi Loads	Settlements
Number of Transformers	TASMo
Transformer Size	TASMo
Transmission Line Length	TASMo
Substation Costs	
Substation Costs (Total)	Project Files (TFO submissions)
Transformer Costs	Project Files (TFO submissions)
Breaker Costs	Project Files (TFO submissions)
Break Down of Project Costs	
Labour	TFO issued PPS or final actuals where available
Sub-Equipment	TFO issued PPS or final actuals where available
Protection	TFO issued PPS or final actuals where available
SCADA	TFO issued PPS or final actuals where available
Transmission Line Costs	TFO issued PPS or final actuals where available
Overhead	TFO issued PPS or final actuals where available
Customer Contributions	
Standard vs. Optional Costs	Customer Contribution Decisions
System vs. Customer-Related Costs	Customer Contribution Decisions
Actual Contribution	Customer Contribution Decisions, Finance
Tariff Year Applied	Customer Contribution Decisions
Contract Term (years)	Customer Contribution Decisions

Findings

Data Analysis

Collection of Additional Information

The AESO distributed a preliminary results report of the customer contribution policy study to the stakeholder community on May 12, 2006. Comments from stakeholders suggested that there were some inconsistencies in the data that required further review. The AESO has conducted a review and analysis of the data and determined that several projects did contain some anomalies when compared to other projects. Further investigation showed that these projects did in fact skew the results of the preliminary analysis. The AESO has provided the results of that review in the final report and has updated the data file.

Other considerations of note in the final report include the use of the Alberta Consumer Price Index for inflation rates. In the preliminary analysis the AESO used the Transmission Construction Price Index, which is a nation-wide index. However, upon further consideration the AESO undertook to analyze the data using the Alberta CPI, which is more relevant to the Alberta market. The AESO notes that the Alberta CPI was utilized for years 1999 through 2005. For the years 2006 and 2007, the AESO utilized inflation as accepted by the Board in EUB Decision 2006-004 (ATCO Gas). The methodology used to develop these rates included “occupational wage adjustments and comparisons of other external wage settlement agreements in other utility and oil and gas companies operating in Alberta” (pg. 64). The table below is reproduced from the Decision:

		2005	2006	2007
Edmonton CPI*	Nov 04	1.9%	1.9%	1.9%
Calgary CPI**	Oct 04	2.3%	2.3%	2.3%
TD Securities Inc	Jan 05	2.3%	N/A	N/A
RBC Dominion Securities	Jan 05	2.4%	2.2%	2.0%
BMO Nesbitt Burns	Jan 05	2.4%	2.4%	2.3%
Beutel, Goodman & Company	Jan 05	2.0%	2.3%	2.2%
Phillips, Hager and North	Jan 05	2.1%	2.1%	2.1%
AVERAGE		2.2%	2.2%	2.1%

* 2005 Greater Edmonton Economic Forecast, November 2004

** City of Calgary Quarterly Economic Report, October 2004

N/A – Forecast not available from these sources

For the “year” category, the AESO notes that the year recorded is the year in which the cost estimate or actuals were received. That is to say, if the PPS estimate was dated June 1, 2003, and no further estimates or projected costs had been received after that date, the year 2003 was recorded. This assumption in effect negates the effect of project construction spanning several years. For example, the planners for the Foster Creek project (#44) submitted the initial Feasibility Study in January 1999, actual construction began in May 2000, plans were revised in June 2000, estimates were re-submitted in

August 2000, June 2001, March 2002 and January 2003. Final reconciled costs were received February 2006. The AESO recognizes that cost estimates change over time, but also assumes that the most recently submitted costs reflect costs incurred “to date” on a project, and likely are a better indicator of the construction-in-progress dollars.

The AESO also endeavored to investigate the circumstances surrounding several outliers specifically in the cases where some of the substation construction projects in the sample appeared to represent one component of larger projects. These large projects (#10, #79 and #170) were identified in the preliminary analysis. In addition to these large projects constructing two or more substations, a number of upgrades were completed at neighbouring substations and other transmission work was also extensive. Subsequently, DTS contract capacities changed at a number of substations as a result of the work, meaning that the total project costs did not align with the individual substation DTS capacities, and total project costs did not reflect the total requested incremental load.

The AESO would like to note that when a determination is made on standard facilities that will be covered by AESO investment, the project is analyzed its entirety. When large projects involve work on several substations, the new DTS capacities at all sites involved are considered when determining the standard facilities. For these projects the total project cost can include DTS increases at more than one substation, thus, the DTS contract capacity as measured at the substation would not necessarily align with the AESO standard cost determination for the total project. To address this and other considerations to be outlined below, the AESO undertook to broaden the data sample and subsequent analysis to include both greenfield projects, as well as projects involving upgrades to existing substations.

The AESO compiled a sample of 78 projects that had customer contribution determinations associated with their projects and had applied for DTS contracts or contract increases. Of this sample, 33 projects were greenfield projects, that is, the project involved the construction of at least one new substation. The remaining 45 projects were “Upgrade” projects. Many of these projects involved the addition of a transformer, breaker, feeder etc. and reflected upgrades to existing PODs. The AESO notes that in a previous report, project # 487 (Updike) was included as a Greenfield project, however it was later determined that the AESO standard facility determination for this project was an upgrade to the existing facilities. Therefore, although a POD was constructed by the customer, the AESO invested in the upgrade costs and not the costs of the new facility. As a result, the AESO has reclassified this project as an Upgrade project.

As part of the final analysis, the following information was gathered for each Greenfield and upgrade project:

Table 2

Information Category	Source of Information
Project #	Internally assigned project numbers
Project Name	The name associated with the project
TFO	The Transmission Facility Owner associated with the project

Project Description	A brief outline of the nature of the project
Greenfield/Upgrade	Determination if project involves new POD construction or upgrades to existing PODs
Year	The recorded year is the year in which actual costs were reconciled, or where unavailable the year of PPS submittal.
Present Value Factor	Calculated using Alberta CPI values to 2005, and recent EUB decision values for 2006 and 2007
Total Project Costs	The total project costs as identified in the most recent customer contribution determination
System-related Costs	The system-related costs as identified in the most recent customer contribution determination
Customer-related Costs	The customer-related costs as identified in the most recent customer contribution determination
AESO Standard Facility Costs	The AESO Standard Facility costs as identified in the most recent customer contribution determination
DTS Contract Capacity	The DTS Contract Capacity as identified in the most recent customer contribution determination
Transmission Line Costs	As identified in the submitted PPS document, or in final actual costs where available
Transmission Line Length	As identified in the submitted PPS document, or Functional Specification document where available

The AESO expected the collection of additional information on this sample might alleviate the data skewing concerns caused by the large multi facility projects. The AESO also felt the inclusion of the upgrades projects in the study was appropriate, as the AESO's contribution policy is applied to both greenfield and upgrade projects. The results of this analysis, proposed application of the results and supporting rationale are outlined later on in the study.

Finally the AESO performed a number of queries in order to reconfirm certain project information. It was consequently determined that the transmission line length information that was identified in the raw data was not representative of the actual lines constructed and included in the costs of the project. Further investigation enabled the AESO to determine the added line lengths that resulted from the project construction. These revised transmission line lengths are listed in the data sheets. Further analysis on the transmission line length data, substation cost data and other considerations outlined above are discussed in the following sections.

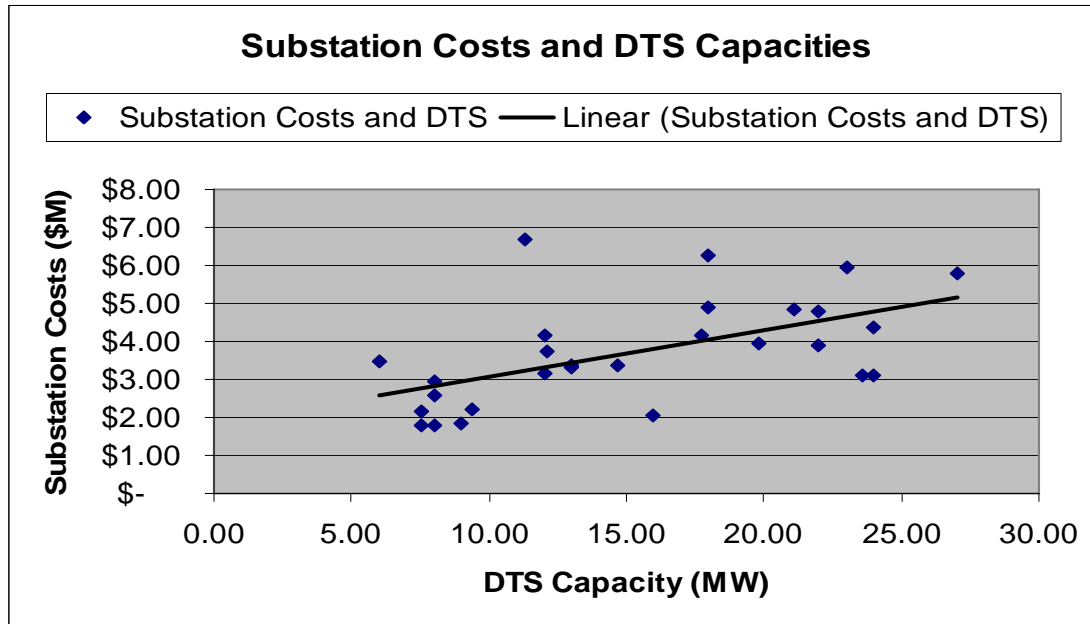
Substation Costs

Substation cost data was updated to account for the following considerations:

- Use of the Alberta CPI for inflation rates, rather than the Transmission Construction Price Index; and
- Revision of DTS contract capacities at some substations to reflect the current contracted amount – this would account for staged load contracts or contract increases resulting from load growth.

Figure 2 below shows the DTS contract capacity associated with the substation, and the substation costs including labour, installation and material costs. The substation costs do not include any transmission line costs.

Figure 2



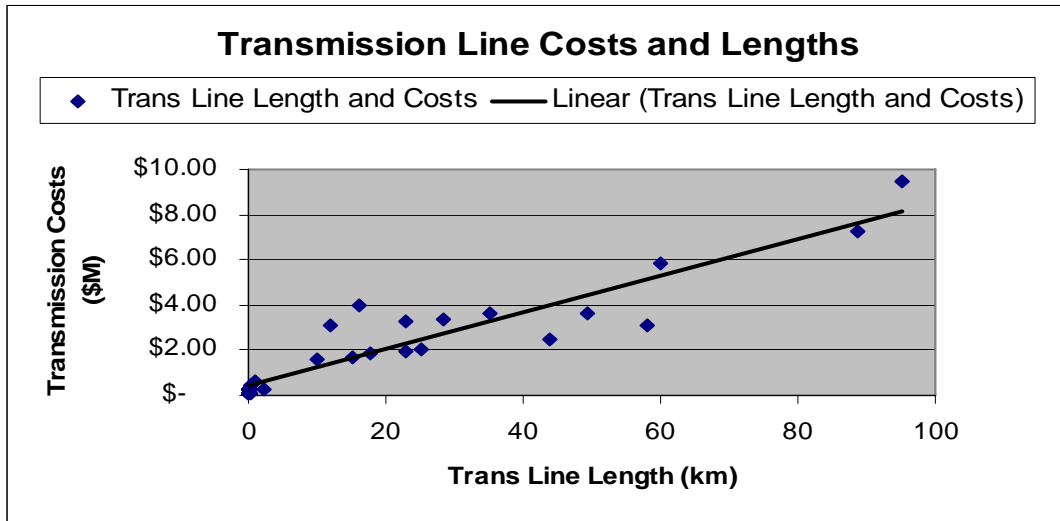
The resulting equation is $y = \$1.848M + (\$0.122M \times DTS)$. This relationship showed a higher correlation ($r^2 = 0.314$) than the line function $y = \$1.910M + (\$0.105M \times DTS)$ and correlation of $r^2=0.255$ found in the preliminary results. This higher correlation is considered to be attributable to the considerations outlined above.

Transmission Line Costs

Further investigation into transmission line costs and lengths revealed some anomalies. The transmission line lengths included in the preliminary analysis were misaligned – that is, the line lengths included all lines up to and leaving a substation, which may or may not have been included in the construction of the project. The AESO was able to further dissect the information, to determine only the line lengths that were constructed and included as part of a total project costs.

Figure 3 reflects the revised line lengths and the associated costs.

Figure 3



This chart identifies a very strong relationship between line costs and line lengths. The line function for the data is $y = \$0.414M + (\$0.081M \times \text{km})$. The correlation factor is $r^2 = 0.868$.

A number of projects indicated transmission costs, however lines were not constructed for the project. In reviewing project information, it appears that a number of elements can contribute to transmission costs without line construction taking place. Some of these elements include the costs of transmission surveys, simple renumbering of transmission lines, or moving transmission lines. This could account for the y-intercept value of \$414,000. The data also indicates a cost of approximately \$81,000 per km of transmission line.

The AESO would like to note that while the exercise to further clarify the data was important and fruitful, the AESO feels the development of the investment function should not solely rely on statistical analysis. Generally accepted rate design principles in cooperation with the data and the legislative framework in which the AESO operates must be taken into consideration. The AESO believes that even though the statistical data may demonstrate, for example, a strong correlation in transmission line length, the AESO does not propose to develop a customer contribution policy based solely upon these findings. The EUA has previously mandated a postage stamp principle, and has not historically supported a distance based principle. The AESO's final customer contribution proposal and supporting rationale is provided in this analysis.

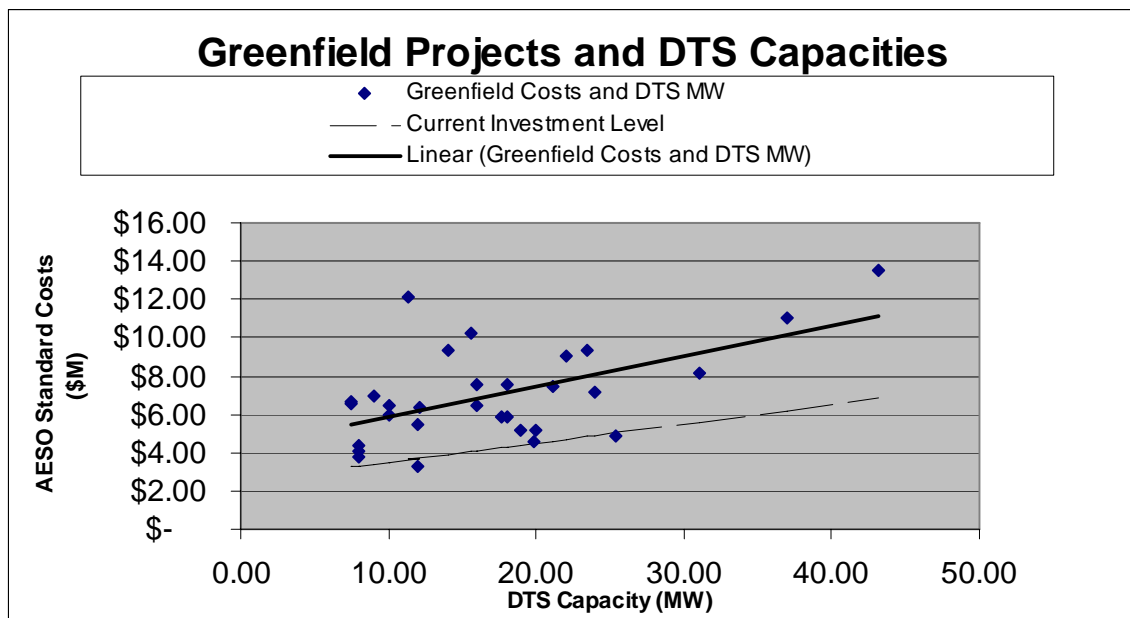
Greenfield Construction

The analysis considered data from a total of 78 projects initiated during the 1999-2006 period. All of these projects were load-serving and had dependent customer contribution determinations. Information from the customer contribution determinations was extracted for each of these projects. For the final analysis, each project was designated as either **Greenfield Construction**, that is, the construction of a POD and (where applicable) associated transmission lines, or **Upgrade projects**, which were identified as those

projects that involved additions or upgrades to existing PODs. Of the 78 projects, 33 were determined to be Greenfield projects. Of the 33 Greenfield projects, three projects (#86 Melito, # 103 Kidney Lake and #341 Briker) were removed from the Greenfield analysis as the projects were deemed to be 100% system-related, making AESO Standard Facility costs \$0. From the sample, 44 of the projects were determined to be Upgrade projects, and from the 44 projects, one project (#165 Mannix) was removed the Upgrade project analysis, as the costs were determined to be 100% system-related.

Figure 4 shows the relationship between the AESO Standard Facility determinations for Greenfield project construction and DTS contract capacity. The currently approved investment level is also provided for comparison purposes.

Figure 4



The line equation represented is $y = \$4.451 + (\$0.154M \times DTS)$, and has correlation of $r^2 = 0.261$. Of note is that 25 Greenfield projects included transmission line construction and costs, while 5 projects (#34 Lloydminister, #130 Enmax Sub #24, #170 UNC Terrace Expansion, #506 Cloverbar and #333 Enmax Sub #7) did not include transmission line costs.

The projects in the data set exhibit significant variability or “scatter”. For example, three projects near 12MW capacity had project costs of \$3.3, \$5.4 and \$4.6 million. The variability reflects different amounts of radial line required for interconnection, different substation configurations, varying geography and construction conditions, and varying levels of complexity for each interconnection.

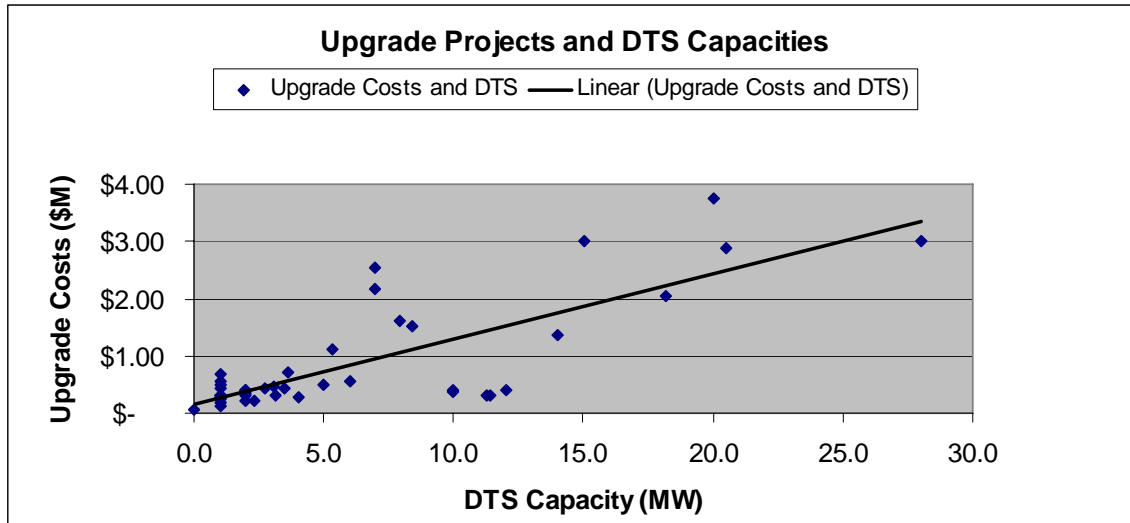
Upgrade Projects

For the Upgrade projects, a sample of 44 projects was used. While Greenfield projects included the cost of transmission lines, the Upgrade project sample included only one

project which had incurred transmission line costs. As mentioned previously, project # 487 (Updike) involved the construction of new facilities that were deemed in excess of AESO standard facilities.

Figure 5 provides the relationship between the standard facility cost upgrades at a POD versus the requested contract capacity increase.

Figure 5



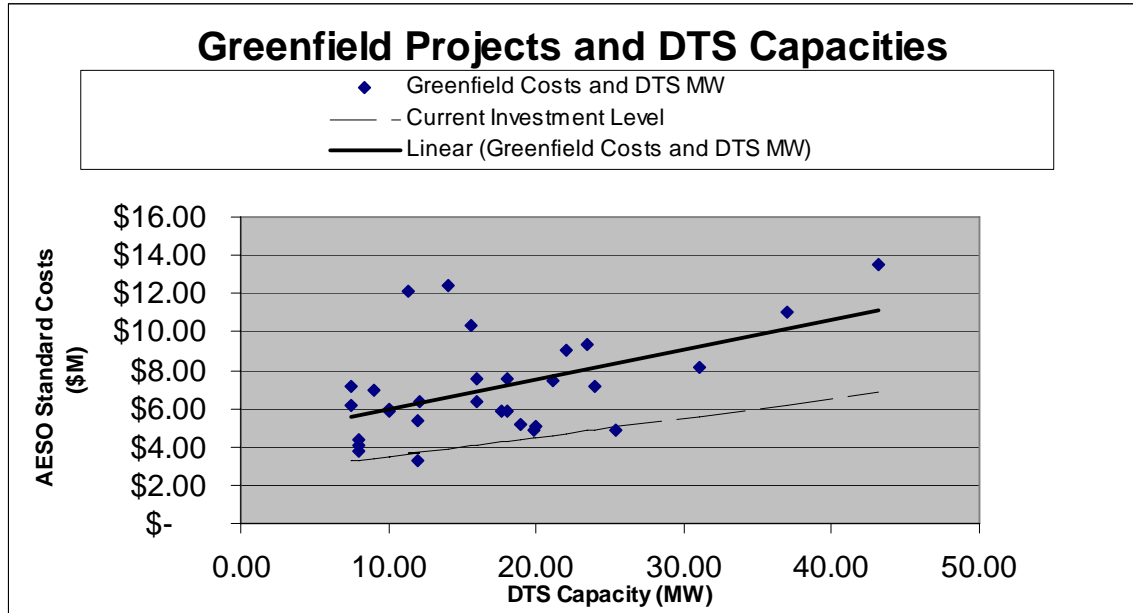
The graph has a trend line equation of $y = \$0.163M \times (\$0.113M \times \text{DTS})$. The correlation factor is $r^2 = 0.62$, indicating a fairly good relationship between requested DTS contract capacity increases and the costs associated with Upgrade projects.

Cost Function Determination

As a result of extensive consultation with stakeholders the study has investigated numerous considerations in the determination of the investment cost function. As noted above, the AESO investigated the use of data from both greenfield and “upgrade” projects that were constructed between 1999 through 2006. Upon further stakeholder consultation and the desire to match the investment function with proposed rates the AESO has determined that a combination of greenfield data along with incremental data collected from the Transmission Cost Causation Study should be used in the determination of the investment cost function. The following sections will outline the incremental data collected along with supporting detail and rationale regarding the proposed investment cost function.

As noted above the AESO believes the data from the greenfield projects should be the primary source of the investment function. Greenfield projects involve the construction of substations and transmission lines. For a new customer wishing to interconnect, a minimum investment amount should be based on the costs of the construction of the substation and associated lines. Figure 6 below reproduces the greenfield function comparing it to the current investment function of \$2.5 million investment allowance for new PODs, and the additional \$100,000 per MW of project capacity.

Figure 6



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.

The following table summaries the cost functions that demonstrated the highest correlation in the study.

Table 3

Analysis	Cost Function (\$M)	r ²
Substation Costs	$y = \$1.848 + (\$0.122 \times \text{DTS})$	0.314
Transmission Line Costs	$y = \$0.414 + (\$0.081 \times \text{km})$	0.868
Greenfield Project Costs	$y = \$4.451 + (\$0.154 \times \text{DTS})$	0.261
Current Investment Function	$y = \$2.500 + (\$0.100 \times \text{DTS})$	n/a

Although the y-intercept values are quite varied, the slope values for the different analyses range from \$113,000 per MW of DTS capacity to \$154,000 per MW (the current investment function has a slope of \$100,000 per MW of DTS). The average of all the slopes (excluding the transmission line which is function of the length in kilometers) is \$122,250 per MW.

The data in Figure 6 has a regression coefficient of 0.26, which indicates moderate positive correlation between project costs and DTS capacity. To assess whether projects of different sizes exhibited different cost functions, the AESO analyzed data subsets by dividing the 30 projects using different DTS capacity thresholds. The AESO found no threshold which provided regression coefficients better than 0.26 for both data subsets. (This analysis was somewhat limited by the number of projects in the total data set, since sample sizes of less than 30 generally provide lower-confidence representations of a total population.) Non-linear regression analysis was also completed, but similarly did not

provide better regression coefficients than the linear analysis. The AESO therefore considers that the single straight-line average cost function revealed in the graph above provides the best representation of the 30 greenfield project costs, as follows:

$$\text{Greenfield construction costs} = \$4.451 + (\$0.154 \text{ million} \times \text{DTS})$$

Although the variability of costs within the data set is significant, the projects nevertheless exhibit a clear trend of cost increasing as capacity increases. Combined with the moderate regression coefficient, the AESO concludes this equation is a reasonable average cost function for recent transmission interconnections.

The intent of a cost function to be developed for the AESO's contribution policy is that it must reasonably represent all transmission interconnections – not just recent ones – primarily because the cost function will provide the basis for the Point of Delivery charge in the DTS rate that applies to all DTS services. Some stakeholders voiced concerns that the data set used to develop the average cost function above did not include any interconnection projects with DTS capacities less than 7.5MW, although 166 DTS PODs – about one-third of all DTS PODs – currently have capacities in that range.

The AESO acknowledges stakeholder assertions that costs included in the recent project data set may reflect standard facilities potentially sized for reasons beyond meeting the customer's load requirements. For example, equipment sizes are standardized for inventory and maintenance efficiencies, projects may be interconnected to nearby facilities at higher voltages than required, and equipment larger than needed to supply the customer's load may be installed in expectation of future load growth or additional services at the substation. The project cost may accordingly be higher than the minimum cost which could be incurred to interconnect the load, and should not unfairly result in a high fixed component over which the customer can exhibit little control.

Stakeholders also expressed concerns regarding the robustness of a single linear function in representing project costs, especially for smaller projects which are not represented in the recent project data set. The AESO notes that project costs exhibit significant "scatter" around any single linear cost function, and an average fixed component could attribute significant costs to a project which were not actually incurred. (This becomes even more of a concern when the cost function is used as the basis for rates, as is the result of the alignment to costs of both investment policy and rates directed in Decision 2005-096.) As an alternative, a minimum-intercept method may generally be "more accurate" than other methods for establishing such a component, when used for distribution system cost classification (see, for example, the NARUC *Electric Utility Cost Allocation Manual*, January 1992, p. 92).

In response to stakeholder concerns that AESO investigated:

- a minimum intercept approach rather than the average to establish the customer-related component of the cost function and,
- a two-part cost function to represent both minimum costs for smaller projects and average costs for larger projects

Sample of Projects Less than 7.5MW

The results of the Customer Contribution Study were presented to stakeholders in June 2006. The AESO sample data used in the Customer Contribution Study did not contain projects less than 7.5MW in size. Stakeholders voiced concerns that the lack of small projects would not address the specific rate and investment concerns of customers with small DTS contracts.

Consequently, the AESO undertook to provide a sample of projects of less than 7.5MW. The AESO examined the POD cost information included in the *Transmission Cost Causation Study*. The AESO found 13 projects in the original TFO data used in the *Transmission Cost Causation Study* which satisfied the following five conditions:

- (a) Costs must represent gross book value of the interconnection, and exclude depreciation and customer contributions.
- (b) Interconnections must have an installation year assigned, to allow escalation to 2007 dollars.
- (c) Interconnections must have been installed within the past 20 years, to ensure reasonable compliance with current standards and avoid discrepancies due to upgrades and capital maintenance that likely occur at older substations.
- (d) Interconnections must include greenfield substations only for consistency with the recent project data.
- (e) Interconnections must be load-only, as costs for dual-use substations are generally not reflective of costs at load-only sites.

Costs for the 13 projects were escalated to 2007 dollars and then used to determine the fixed component of the cost function using a minimum-intercept method. The minimum intercept was determined by multiplying the average cost function developed from the 30 project data set by a fraction such that it was equal to or less than the cost of each of the 13 TFO data projects, and then extending that function to intercept the y-axis. The y-axis intercept defines the no-load or absolute minimum cost, which was \$0.947 million

The following table illustrates the data drawn from the Cost Causation Study.

Table 4

Project Reference	In-Service Date	DTS Capacity MW	Cost Estimate 2007 \$000,000
TFO Project #1	1990	0.1	1.71
TFO Project #2	1987	1.5	0.93
TFO Project #3	1990	4.1	1.33
TFO Project #4	1991	4.2	6.15
TFO Project #5	1988	4.8	2.56
TFO Project #6	1989	5.1	6.32
TFO Project #7	1997	5.6	4.24
TFO Project #8	1987	5.8	3.96
TFO Project #9	1997	6.0	2.48
TFO Project #10	1990	6.1	9.24

TFO Project #11	1987	6.3	1.81
TFO Project #12	1993	6.4	7.72
TFO Project #13	1990	6.6	4.08

Linear interpolation establishes the cost function up to 7.5 MW to be:

$$\begin{aligned} \text{Interpolated Function} &= \$0.947 \text{ million} \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \end{aligned}$$

Raw Cost Function

The proposed raw cost function is extrapolated by combining the cost data collected for the greenfield data, with the cost data for small projects (i.e. 7.5MW or less) as identified above.

Based on the discussion above, the AESO recommends the complete proposed raw cost function arrived at by combining the average cost function for the greenfield data, with the interpolated function developed from small projects as identified above. More specifically, the AESO recommends that the **interpolated** function be used to represent the costs of projects **up to** 7.5 MW of capacity, and the **average cost** function be used to represent the costs of projects **above** 7.5 MW of capacity.

The AESO recognizes that such a two-part function, if applied mechanically to all project capacities, would not total the sum of all project costs since the interpolated function would under-represent the costs of smaller projects. However, the cost function will be scaled to represent total costs whether used to set an investment level or in rate design, and total costs will therefore ultimately be fully represented.

The complete derivation of the proposed POD cost function is summarized as follows:

- (a) As discussed in the preceding section, the average cost function for the 30 greenfield project data is reproduced, and determined to be:

Equation 1

$$\text{Average Cost} = \$4.451 \text{ million} + (\$0.154 \text{ million/MW} \times \text{DTS Capacity})$$

- (b) The minimum cost function was then calculated using the data collected on small projects from the Cost Causation Study (referred to as “Interpolated Function”). The average cost function was reduced to a level that represents the lowest threshold below which no project costs were recorded. This was accomplished by multiplying the average cost function by a single factor of 0.21275. The y-intercept of this minimum cost function is considered to represent the minimum fixed cost for any projects. The resulting equation is:

Equation 2

$$\text{Minimum Cost} = \$0.947 \text{ million} + (\$0.033 \text{ million/MW} \times \text{DTS Capacity})$$

- (c) Interpolating between the 7.5 MW point on the average cost function (Equation 1), and the y-intercept of \$0.947 million (from Equation 2), generates a linear function (\$/MW) as provided in Equation 4 below. This function represents the interpolated costs for projects ranging from 0-7.5 MW.

Equation 3

$$\begin{aligned}\text{Cost at 7.5 MW} &= \$4.451 \text{ million} + (\$0.154 \text{ million} \times 7.5 \text{ MW}) \\ &= \$5.607 \text{ million}\end{aligned}$$

The slope of this line is then calculated:

Equation 4

$$\begin{aligned}\text{Slope of line 0 MW to 7.5 MW} &= (\$5.607 \text{ million} - \$0.947 \text{ million}) / 7.5 \text{ MW} \\ &= \$0.621 \text{ million/MW}\end{aligned}$$

- (d) The AESO therefore recommends the following cost function:

Equation 5

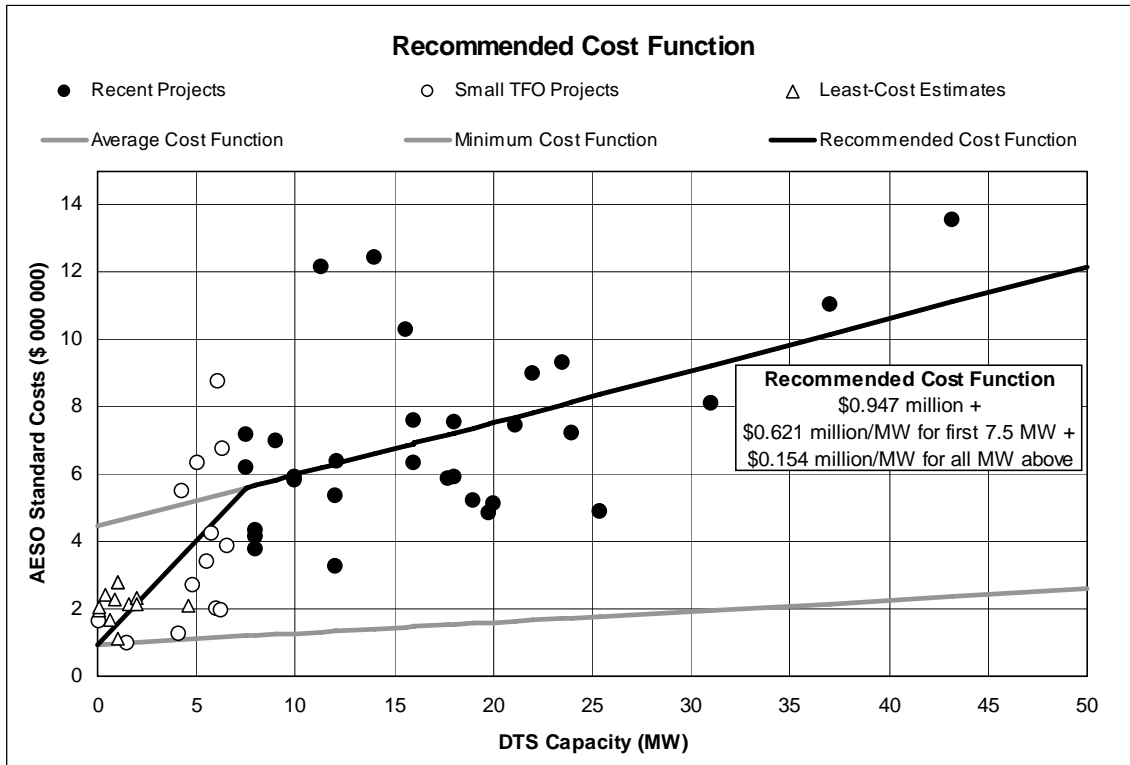
$$\begin{aligned}\text{Recommended Cost} &= \$0.947 \text{ million} \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW})\end{aligned}$$

The AESO considers the recommended cost function (Equation 5) to appropriately reflect project costs for the purposes of establishing investment levels and for rate design in the AESO's Tariff.

The AESO recommends the proposed cost function for several reasons. Primarily, the AESO considers it appropriate to establish the fixed component of the cost function through a minimum intercept analysis as performed above. A fixed component represents a cost a customer cannot avoid regardless of what decisions the customer makes; that cost should therefore be the minimum cost associated with a project rather than the average cost. Minimum intercept analysis is frequently used to determine the fixed component of a utility's rates. The AESO also notes that data scatter appears greatest for smaller projects, which increases concern with applying an average cost function to those projects.

Figure 7 below depicts the derivation of the raw cost function.

Figure 7



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.

The recommended cost function was developed using data for load-only projects. Where a project provided interconnection of both load and generation or of multiple loads, the cost function must be adjusted to reflect the “substation fraction” approach established by the EUB during the course of the AESO’s 2005-2006 GTA. The AESO notes that all but two transmission substations serving multiple services (either load and generation or multiple loads) have more than 7.5 MW of total contract capacity. Such substations are therefore best represented by Equation 1, which indicates that such substations have a minimum average cost of \$4.451 million to be shared between the interconnected services using the substation fraction. In the recommended cost function, this minimum average cost is replaced by the interpolated function provided in Equation 3, and the interpolated function should likewise be shared between services using the substation fraction. The AESO therefore proposes that the recommended cost function incorporate the substation fraction (“SF”) into its first two components as follows:

Equation 6

$$\begin{aligned} \text{DTS POD Costs} &= \$0.947 \text{ million} \times \text{SF} \\ &+ (\$0.621 \text{ million/MW} \times \text{SF} \times \text{first 7.5 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW}) \end{aligned}$$

The third component represents the average POD cost increase per MW of DTS capacity, and should not include the substation fraction.

Data Reasonableness Assessment

In addition to utilizing the Transmission Cost Causation Study data the AESO tested the reasonableness of these results as outlined below.

The first tested involved a review of the average cost function of the Transmission Costs Causation Study. The AESO first reduced the TFO POD data collected for the *Transmission Cost Causation Study* to only those PODs where the vintage was known (approximately 109 PODs). The project costs were then escalated to current day dollars. Although the data did not include enough detail to validate that only standard facilities were included or that interconnections were reasonably representative of current standards, the AESO performed a simple linear regression analysis of the interconnection projects included. The resulting average costs equation was:

$$\text{Average TFO Data Costs} = \$5.074 \text{ million} + (\$0.115 \text{ million/MW} \times \text{DTS Capacity})$$

The TFO data set represented by the equation above has a regression coefficient of 0.18, less than that of the 30-project data set (greenfield projects). However, this equation is reasonably close to the greenfield project equation, and suggesting the equation above is a reasonable representation of average Point of Delivery costs.

The second test involved the review of some material presented in the AESO's 2005-2006 General Tariff Application. The AESO prepared least cost estimates for several stand-alone DTS services as part of its analysis of Customer-Owned Substation Credits. The AESO compared the least cost estimates (escalated to 2007 dollars) for the 12 stand-alone DTS services of 5 MW or less from that analysis to the minimum cost function developed through the Transmission Cost Study as discussed above, and found that the minimum cost function was equal to or less than each of the least-cost estimates. This suggests the minimum cost function is a reasonable representation of minimum costs for small DTS interconnections.

The following table illustrates the results of the analysis of estimated projects with DTS capacity of 5 MW or less, as provided in the AESO 2005-2006 GTA IR response for FIRM.AESO-234(b).

Table 5

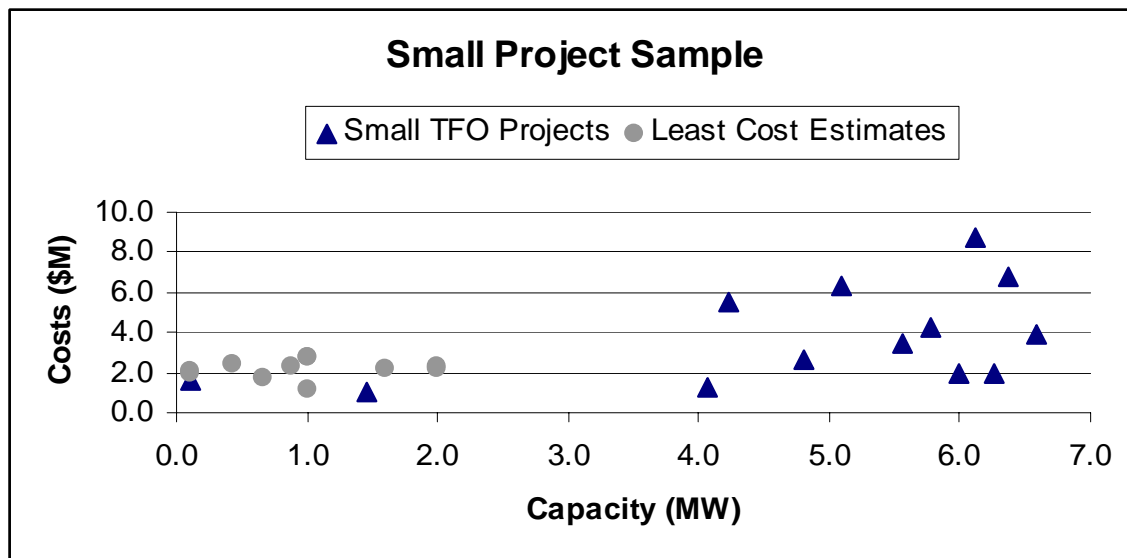
Substation Name	In-Service Date	DTS Capacity MW	Least Cost Estimate \$000,000	Least Cost Estimate 2007 \$000,000
Bear Creek	Nov 2002	0.1	1.75	1.98
Carseland Cogen	Jul 2001	0.1	1.75	2.04
Namaka	Jul 2001	2.0	1.98	2.31
Nexen #1	Sep 2001	2.0	1.83	2.14

Foster Creek	Jan 2003	1.6	1.98	2.14
Cowley Ridge	Jul 2003	0.66	1.55	1.68
Oldman River	Jul 2003	1.0	2.58	2.79
Magrath 226S	Jul 2004	0.43	2.29	2.44
McBride Lake	Feb 2003	0.88	2.13	2.30
Eyehill 514S BP Hayter	Aug 2000	1.0	2.32	2.77
Express Hardisty	Aug 2000	4.6	1.74	2.08
Wabamun Standby	Oct 2004	1.0	1.05	1.12
Average		1.28	1.91	2.15

The AESO compared the least cost estimates (escalated to 2007 dollars) for the 12 stand-alone DTS services of 5MW or less from that analysis to the minimum cost function developed as discussed above, and found that the minimum cost function was equal to or less than each of the least cost estimates. This suggests the minimum cost function is a reasonable representation of minimum costs for small DTS interconnections.

The “Small TFO Projects” and “Least Cost Estimate Projects” are displayed graphically below.

Figure 8



Satisfied that the data passed the reasonableness tests outlined above, the AESO performed a simple linear regression analysis of the 13 TFO data projects of less than 7.5 MW capacity, that were used in the minimum-intercept analysis. The resulting average cost equation for these small projects was:

$$\text{Average Small Project Costs} = \$0.940 \text{ million} + (\$0.595 \text{ million/MW} \times \text{DTS Capacity})$$

The 13-project data set represented by this equation has a regression coefficient of 0.24, which indicates moderate positive correlation between project costs and DTS capacity. This equation is also quite close to the interpolated Small TFO Project cost function

provided earlier, and suggests this equation is both a transition from minimum to average costs and a reasonable representation of average Point of Delivery costs for small interconnections up to 7.5 MW capacity.

Although the AESO analyzed the TFO data used in the *Transmission Cost Causation Study* and least-cost estimates provided in the AESO's 2005-2006 GTA to assess the reasonableness of the recommended cost function, these additional sources were not subject to the same detailed investigation and rigorous analysis as the 30 recent projects on which the recommended cost function was primarily based. The use of recent projects allows data to be examined and validated, whereas data from the additional sources does not provide the detail needed for full validation. The AESO therefore considers the 30-project data set to represent the best data available upon which to base the cost function.

Applying the 80/20 Multiplier

The final analysis of the study, as identified in Direction 13A, is meant to address the third component of the Direction:

Determine an appropriate multiplier such that 80% of projects do not pay a contribution.

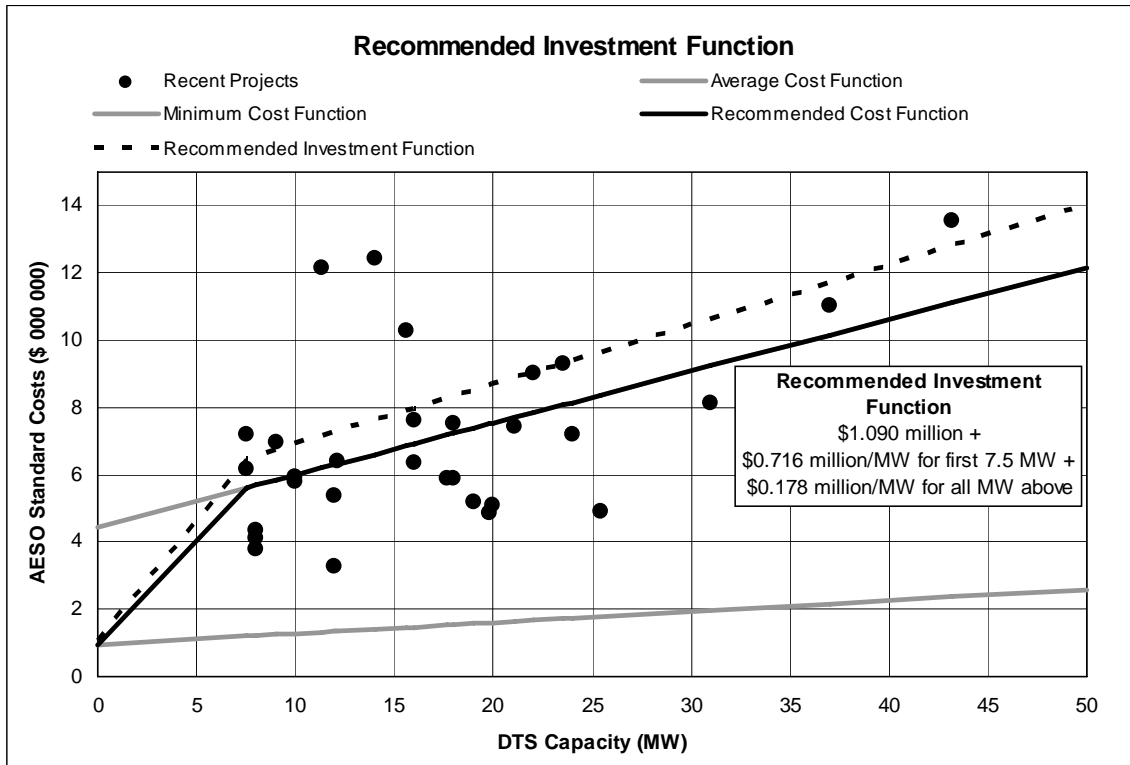
The AESO notes that the EUB agrees that the 80/20 criterion is appropriate for the design of the maximum investment formula. In EUB Decision 2001-6, the AESO's predecessor (EAL) introduced this criterion, noting that setting an investment level in this manner would have the effect of minimizing intergenerational inequities. The AESO continues to agree that the 80/20 rule is adopted in order to best harmonize with DISCO contribution policies, preserving the balance between the need of new customers for service and for service without a need for subsidy from existing customers. The criterion supports the principle that most new customers will not see a different cost of system connection than existing customers, and existing customers should not bear any extraordinary costs of system expansion.

The final analysis component of the study proposes an investment cost function. Then the AESO investigated different multipliers to achieve an investment function such that 80% of projects would not pay a contribution. The AESO determined several multipliers would have maintained the 80/20 rule of thumb requirement but utilized the minimum multiplier in the final investment function.

Further analysis on the application of the appropriate multiplier follows.

Using the current sample data from the original study and the data on smaller projects, a proposed investment function is depicted below.

Figure 9



Applying a multiplier of 1.15149 to the cost function of:

Equation 7

$$y = \$0.947 \text{ million} \times \text{SF} + (\$0.621 \text{ million/MW} \times \text{SF} \times \text{first 7.5 MW of DTS Capacity}) + (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW})$$

indicates a line function of:

Equation 8

$$y = \$1.090 \text{ million} \times \text{SF} + (\$0.716 \text{ million/MW} \times \text{SF} \times \text{first 7.5 MW of DTS Capacity}) + (\$0.178 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW})$$

such that 24 of the 30 (or 80%) of projects from the Customer Contribution Study, are fully covered by investment as demonstrated in the figure above.

The resulting equation assumes contract terms of 20 years. Therefore, the per year investment level is:

Equation 9

$$y = \$54,500/\text{year of contract term} \times \text{SF} + (\$35,800/\text{MW/year of contract term up to 7.5MW} \times \text{SF}) + (\$8,900/\text{MW/year of contract term greater than 7.5MW})$$

Conclusions

The AESO believes this study meets the requirements of Decision 2005-096 and provides a solid foundation for the proposed maximum investment function.

While the preliminary analysis of standard and customer-related costs did not support a strong correlation between the variables and failed to account for upgrades at existing facilities, the results of the final analysis showed higher correlations.

The AESO notes that the transmission line length and cost function showed high correlative values ($r^2=0.868$). Upgrade project costs and DTS contract capacities indicated a correlative value of $r^2=0.617$. Greenfield and substation construction costs showed lower correlations with DTS contract capacities ($r^2=0.261$ and $r^2=0.314$ respectively).

The proposed cost function equation is based on the establishment of a fixed component of the cost function through a minimum intercept analysis. The fixed component represents costs a customer cannot avoid regardless of what decisions the customer makes. The recommended cost function is:

$\$0.947 \text{ million} \times \text{SF}$
+ $(\$0.621 \text{ million/MW} \times \text{SF} \times \text{first } 7.5 \text{ MW of DTS Capacity})$
+ $(\$0.154 \text{ million/MW} \times \text{DTS Capacity above } 7.5 \text{ MW})$

When applying the 80/20 multiplier to the sample data, a multiplier of 1.15149 resulted in an investment function such that 80% of projects would not be required to pay a contribution. The resulting investment function proposal is:

$\$1.090 \text{ million} \times \text{SF}$
+ $(\$0.716 \text{ million/MW} \times \text{SF} \times \text{first } 7.5 \text{ MW of DTS Capacity})$
+ $(\$0.178 \text{ million/MW} \times \text{DTS Capacity above } 7.5 \text{ MW})$.

The study data used in the final analysis, including the figures and trend analysis discussed above, are provided in the updated Microsoft Excel workbook.

While the results of the final analysis did not conclude a strong relationship exists between DTS contract capacity and various costs, it may provide useful information on the appropriateness of applying DTS contract MW ranges to a future investment policy function.

The AESO recognizes that the cost information collected to date is inconsistent with respect to categorization of estimates and final costs amongst different TFOs. The Transmission Regulation (AR 174/2004) Section 3 identifies the following regulation for Transmission facility project cost recovery:

13(1) The ISO must make rules respecting the preparation of transmission facility project cost estimates to ensure consistent information requirements, cost reporting and cost estimates by TFOs.

The AESO intends to standardize the submission of cost information, such that going forward the estimates can be compared with cost categories of other projects, to ensure the reasonableness of submitted estimates. This consistency will enable proper cost classification and analysis for future projects.