Customer Contribution Study

Final Analysis

AESO 2007 GTA Terms and Conditions Consultation

June 27, 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 refiling 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 in 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 TASMo (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.

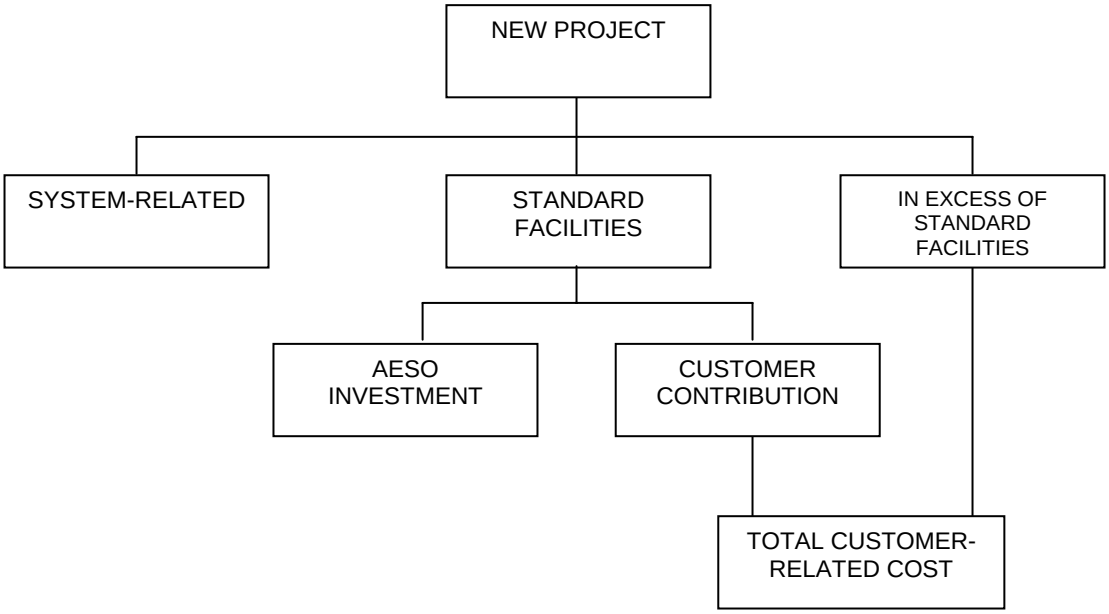
Total substation costs are those costs distinctly associated with substation construction, including labour. Transmission line construction, and work performed at adjacent substations in respect to the project would not be included in substation costs. Transformer and breaker costs are strictly material 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

Final 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 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, 34 projects were “Greenfield” projects, that is, the project involved the construction of at least one new substation. The remaining 44

projects were upgrade projects. Many of these projects involved the addition of a transformer, breaker, feeder etc. and reflected upgrades to existing PODs.

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.

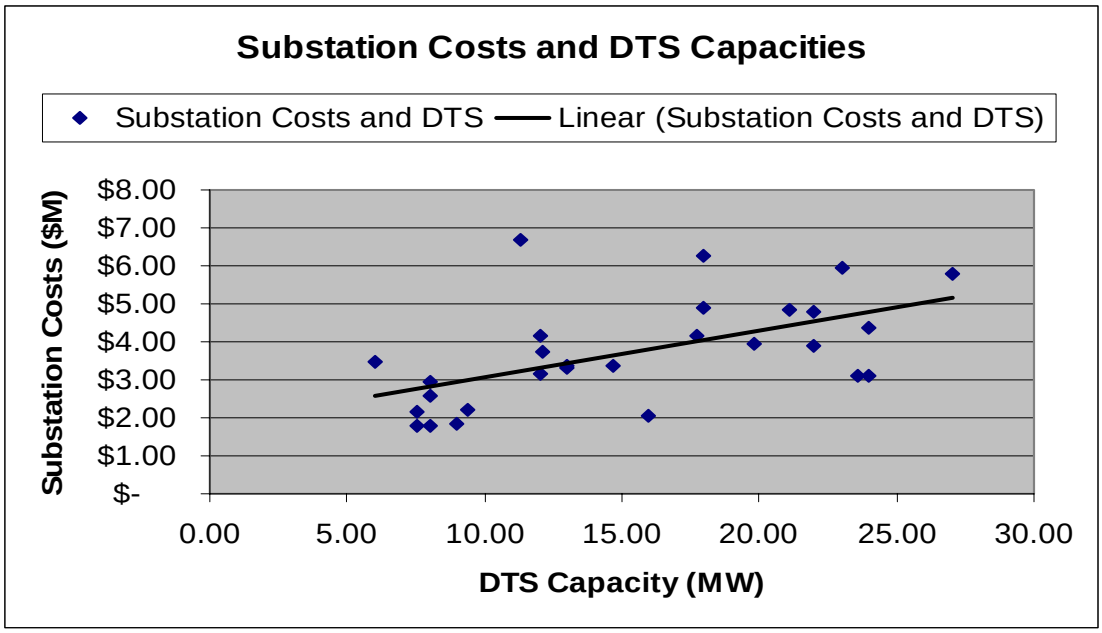
Substation Costs

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 x DTS). This relationship showed a higher correlation (r^2 = 0.314) than the line function y = $1.910M + ($0.105M x 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.

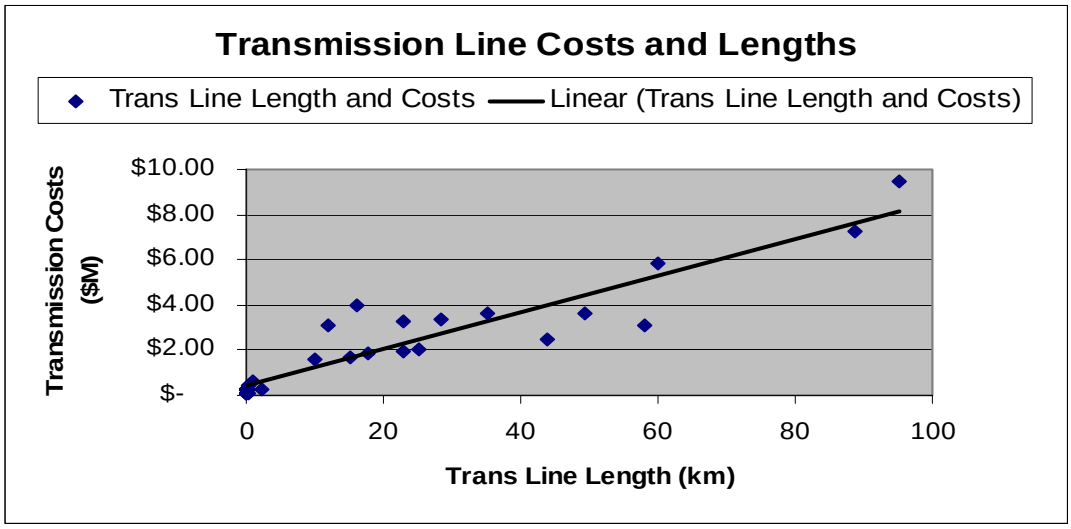
Transmission Line Costs

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 x 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.

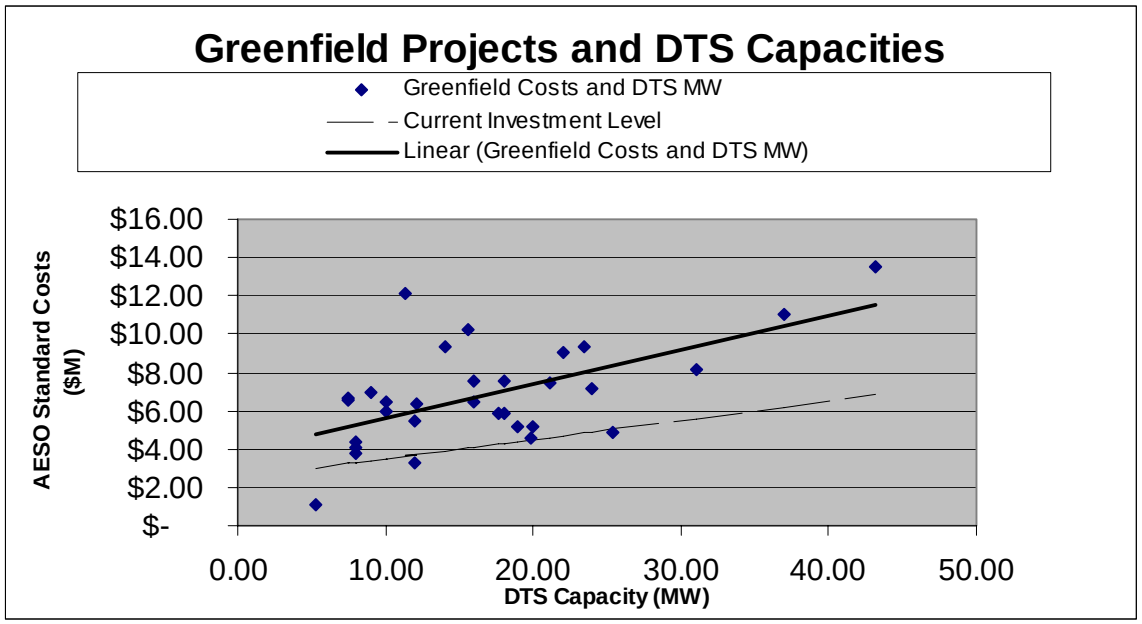
The AESO would like to note that while the exercise to further clarify the data was important and fruitful, the AESO feels the development of the investment function should not solely rely on statistical analysis. Generally accepted rate design principles in cooperation with the data and the legislative 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 basied 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 final 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, 34 were determined to be Greenfield projects. Of the 34 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, forty-three of the projects were determined to be Upgrade projects, and from the 43 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



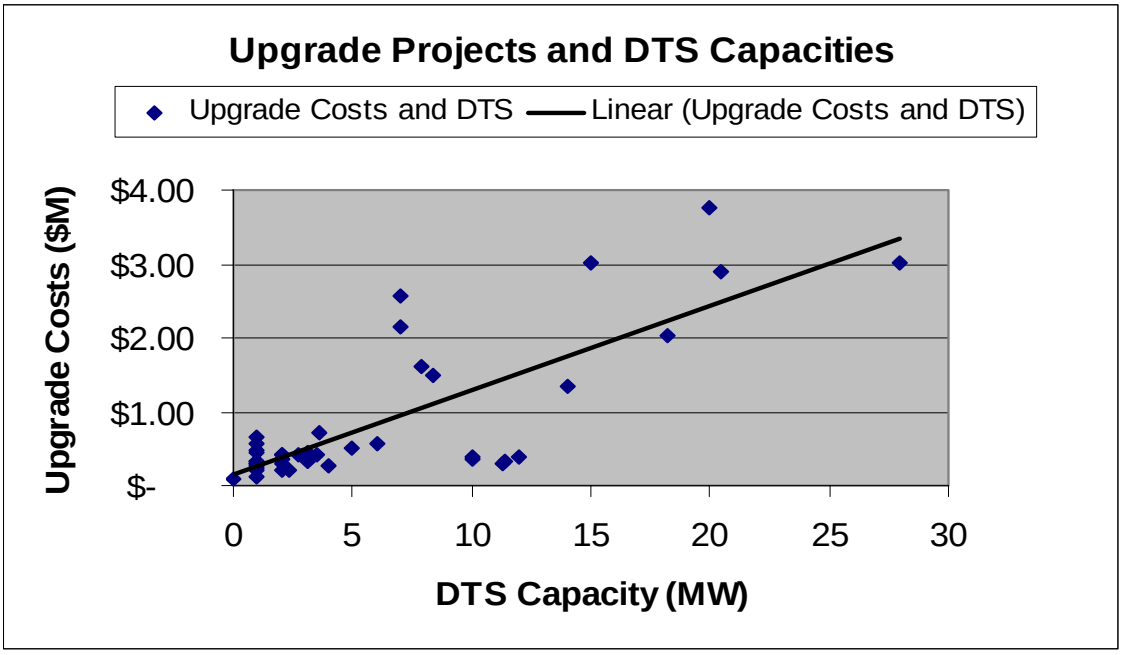
The line equation represented is y = $3.846M + ($0.177M x DTS), and has correlation of r^2 = 0.349. Of note is that 26 Greenfield projects included transmission line construction and costs, while 5 projects (#34 Lloydminister, #130 Enmax Sub #24, #170 UNC Terrace Expansion, #506 Cloverbar and #333 Enmax Sub #7)did not not include transmission line costs.

Upgrade Projects

For the Upgrade projects, a sample of 43 projects was used. While Greenfield projects included the cost of transmission lines, the Upgrade project sample did not include any transmission line costs.

Figure 5 below 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 = $0.154M x ($0.113M x 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.

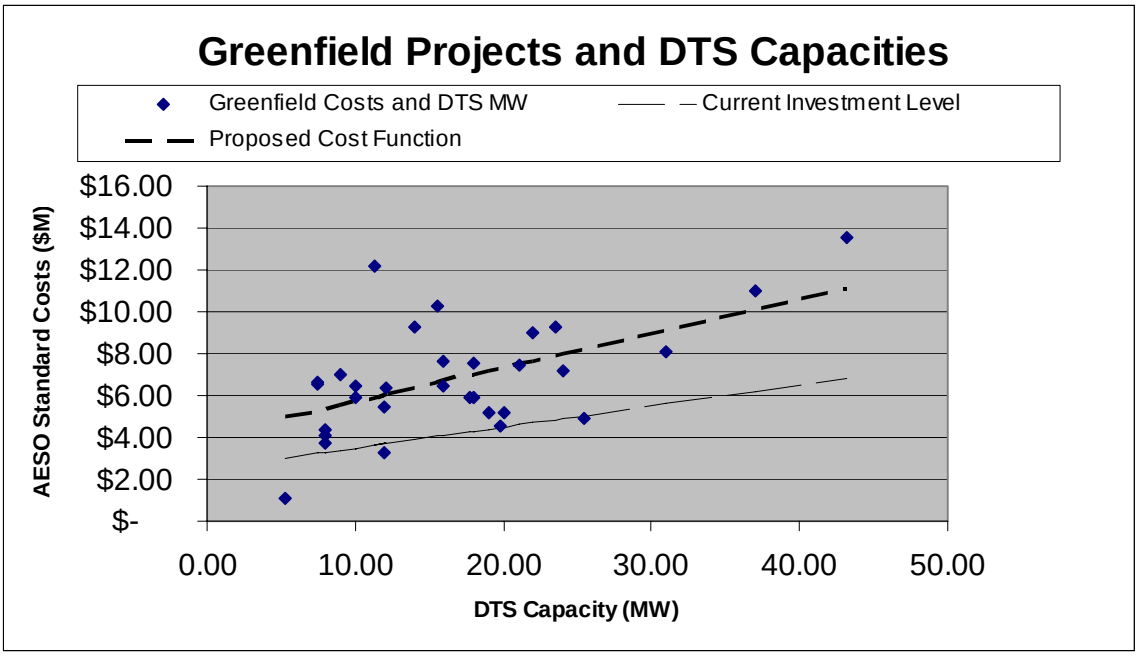
Proposed Cost Function

The results of the final analysis proved to have slightly higher correlation factors than those of the preliminary analysis. As a result the AESO proposes to utilize the final analysis results, rather than use the results from the preliminary analysis in determining the investment function.

The study analyzed the various components of the deconstructed project costs for projects constructed in 1999 through 2006. As mentioned earlier the AESO believes the data from both the "Greenfield" projects along with the Upgrade data set should be considered in the determining an investment function. The AESO suggests that the information of primary importance is the data gathered on Greenfield projects. 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 3 of 30, or 10% 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 x DTS)	0.314
Transmission Line Costs	y = $0.414 + ($0.081 x km)	0.868
Greenfield Project Costs	y = $3.846 + ($0.177 x DTS)	0.349
Upgrade Project Costs	y = $0.154 + ($0.113 x DTS)	0.620
Current Investment Function	y = $2.500 + ($0.100 x 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 $177,000 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 $128,000 per MW.

The AESO proposes that the goal of a contribution policy is a single function that works, on average, for both upgrade and Greenfield projects. Therefore, the best determination of a slope to use in the single function is an average of the slope of the Greenfield project

line function and the slope of the Upgrade project line function, weighted by costs attributable to capacity. The slope of the cost function for Greenfield projects is $0.177 million/MW. For the 31 analyzed projects, the costs attributable to capacity using this slope total 521.96 MW x $0.177 million/MW = $92.4 million. The Greenfield project slope represents the cost of construction of new PODs. The slope of the cost function for Upgrade projects is $0.113 million/MW. For the 43 Upgrade projects included in the sample, the costs attributable to capacity total 258.06 MW x $0.113 million/MW = $29.2 million. The Upgrade projects slope represents the cost of adding capacity at existing PODs.

An average of the two slopes, weighted by costs attributable to capacity reveals:

$$= \frac{[(\$0.177 \text{ million/MW} \times \$92.4 \text{ million}) + (\$0.113 \text{ million/MW} \times \$29.2 \text{ million})]}{(\$92.4 \text{ million} + \$29.2 \text{ million})}$$

= $0.162 million/MW

The y-intercept value should reflect the cost of construction of the substation and any associated transmission line work. This is best determined by the Greenfield project analysis.

The sum of all contracted MWs for the Greenfield projects is 521.96 MW. The average contracted DTS MW capacity is 16.84 MW. Using the "raw" Greenfield cost function of $3.846 million + ($0.177 million x MW), the average cost of Greenfield construction:

= $3.846 million + ($0.177 million x 16.84 MW)
= $6.83 million

Therefore, the total of average costs calculated for all Greenfield projects using the function:

= $6.83 million x 31 projects
= $211.6 million

By back-calculating using the weighted average slope of $0.162 million/MW, the y-intercept to give the same total of average costs:

= $6.83 million – ($0.162 million x 16.84 MW)
= $4.099 million

With this in mind, the proposed cost function has a y-intercept value of $4.099 M. Therefore, the proposed cost function based on the raw data is:

y = $4.099 million + ($0.162 million/MW)

The AESO suggests that using this cost function, and applying a multiplier such that 80% of the sample of Greenfield projects are fully covered by investment is the most appropriate.

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.

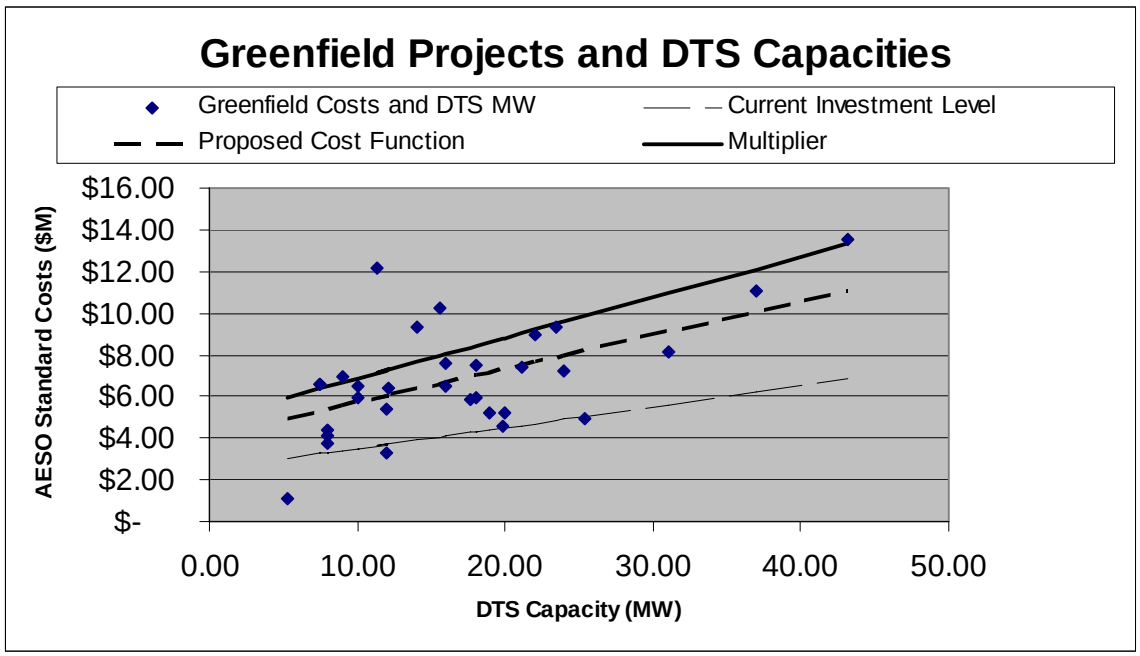
The AESO notes that the EUB agrees that the 80/20 criterion is appropriate for the design of the maximum investment formula. In EUB Decision 2001-6, the AESO's predecessor (EAL) introduced this criterion, noting that setting an investment level in this manner would have the effect of minimizing intergenerational 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.

Further analysis on the application of the appropriate multiplier follows.

Using the current sample data, and graphing the current investment function, (as per Direction 13 of EUB Decision 2005-096), against Greenfield Project costs and DTS contract capacities is demonstrated in Figure 7 below:

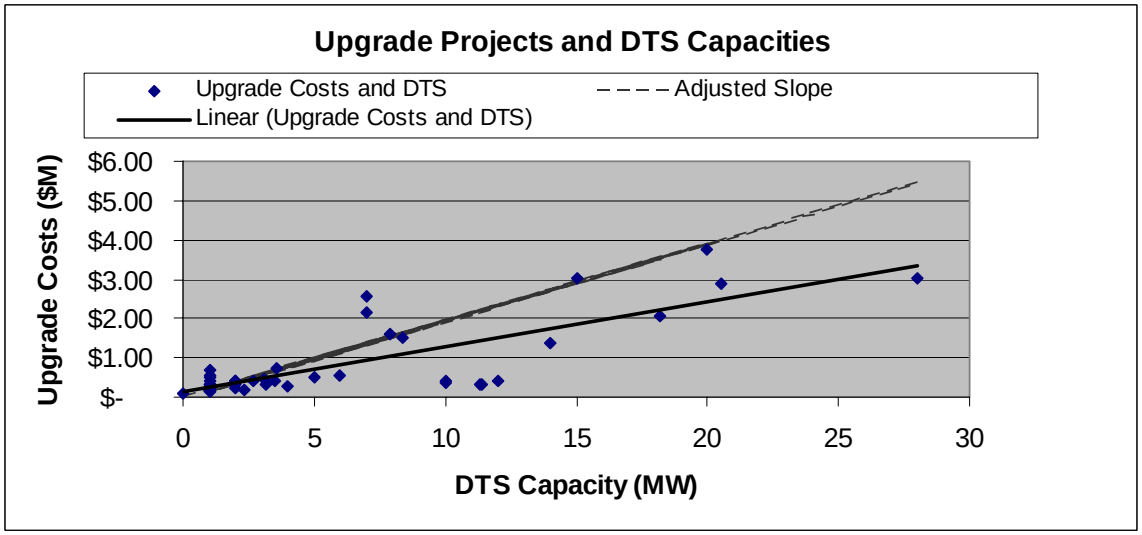
Figure 7



Applying a multiplier of 1.2 to the cost function of y = $4.099M + ($0.162M x DTS) provides a line function of $4.92M + ($0.194 x DTS), such that 25 of the 31, or 80.6% of projects are fully covered by investment is demonstrated in the figure above.

Applying the slope of $194,000 per MW to the Upgrade projects shows the following:

Figure 8



Using this slope, 27 of the 43 Upgrade projects would be fully covered by investment. This indicates that approximately 63% of Upgrade projects would be fully covered by investment. Of note, the previous investment policy allowed for $400,000 per year of

commitment term, so many of these projects increased their DTS capacities by 1.0MW to be eligible for full investment.

Future Projects

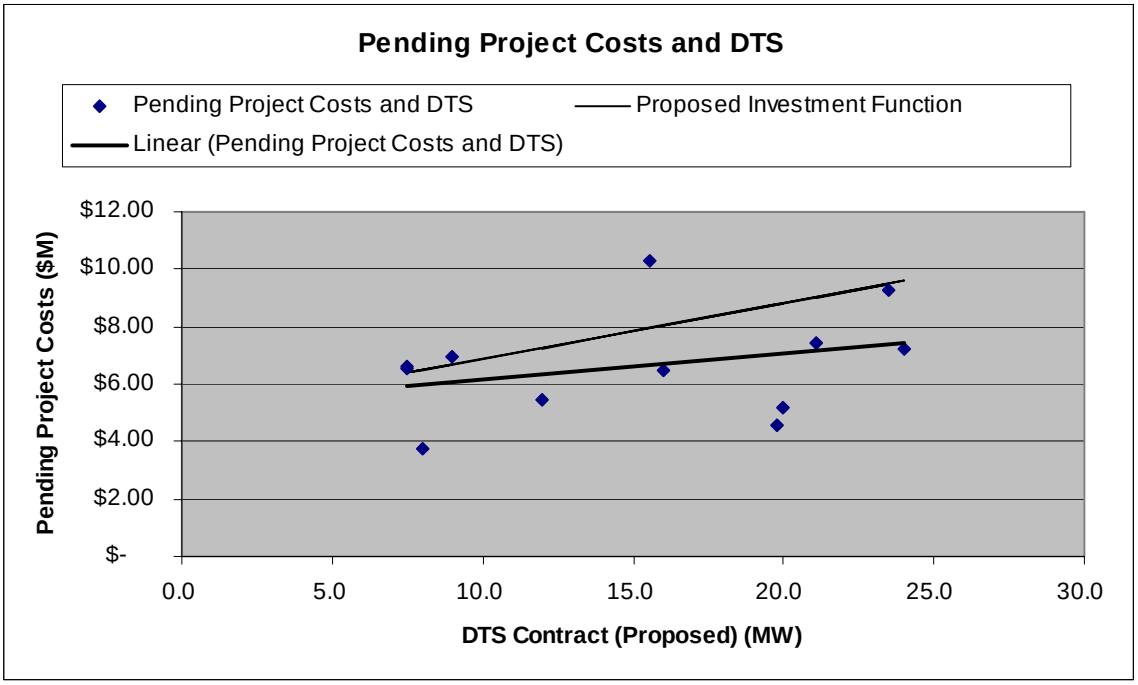
The following table provides a list of pending interconnection projects. This list includes estimated project costs and currently proposed DTS contract capacities.

Table 4

Project #	Project	TFO	Year	PV	AESO Standard ($M)	DTS	Proposed Investment ($M)
333	Enmax #7	ENMAX	2004	1.067	$5.44	12.0	$7.25
343	Bassano	AML	2005	1.045	$10.28	15.6	$7.95
358	Bretona	AML	2004	1.067	$4.57	19.8	$8.77
360	Viscount	AML	2004	1.067	$5.18	20.0	$8.81
385	Terasen Ribstone	ATCO	2004	1.067	$6.54	7.5	$6.38
386	Terasen Wardlow	AML	2004	1.067	$6.98	9.0	$6.67
387	Terasen Peace Butte	AML	2004	1.067	$6.63	7.5	$6.38
420	Air Products	AML	2004	1.067	$3.77	8.0	$6.47
422	TC Edson Gas	AML	2004	1.067	$7.20	24.0	$9.58
425	Enmax #6	ENMAX	2004	1.067	$6.45	16.0	$8.03
433	Christina Lake	AML	2005	1.045	$9.30	23.5	$9.49
443	Whitemud	AML	2005	1.045	$7.43	21.1	$9.02

Applying the proposed investment function of $4.92 M + ($0.194M x DTS), reveals the information below. In the chart, 9 of the 12 (or 75%) of the pending projects would be fully covered by investment. Although the final actual reconciled costs for these projects have yet to be submitted, the proposed investment function appears to very closely meet the intended 80/20 goal.

Figure 9


Pending Project Costs and DTS
Pending Project Costs and DTS
Proposed Investment Function
Linear (Pending Project Costs and DTS)
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
Pending Project Costs ($M)
0.0
5.0
10.0
15.0
20.0
25.0
30.0
DTS Contract (Proposed) (MW)

Conclusions

The AESO believes this study meets the requirements of Decision 2005-096 and provides a solid foundation for the proposed maximum investment formula of $4.92M + $0.194M/MW.

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 results of the final analysis showed slightly 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=0.620. Greenfield and substation construction costs showed lower correlations with DTS contract capacities (r^2=0.349 and r^2=0.314 respectively).

The proposed cost function equation is based on an average of the Upgrade project slopes and Greenfield project slopes, weighted by costs attributable to capacity. This cost function is $4.099M + ($0.162M x DTS contract capacity).

When applying the 80/20 multiplier to the sample data, a multiplier of 1.2 resulted in an investment function such that approximately 80% of projects would not be required to pay a contribution. The resulting investment function proposal is $4.92M + ($0.194M x DTS).

The study data used in the final analysis, including the figures and trend analysis discussed above, are provided in the attached 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.

Next Steps

Interested parties are invited to provide further comments on the information discussed in this paper. All comments will be published on the AESO website a www.aeso.ca as part of the consultation documentation available by following the path Tariff ▶ Current Consultation ▶ 2007 Terms and Conditions.

This discussion provides preliminary background material on the Customer Contribution Study. The AESO intends to conduct further analysis and investigation, and expects that the results and final study will be available at the end of May 2006.

Comments should be provided to Ed Hucman at ed.hucman@aeso.ca and copies to Lee Ann Leduc at leeann.leduc@aeso.ca. In addition, please contact Ed Hucman at (403) 539-2469 or Lee Ann Leduc at (403) 539-2741 (both in Calgary) or by e-mail at the above addresses if you have further questions on this analysis.