

**AESO 2007 Tariff Consultation:
Additional Stakeholder Comments
On July 21, 2006 Revised Tariff Proposals
September 20, 2006**

Written comments were received from:

- ADC — August 15, 2006
- ATCO Electric — September 18, 2006
- Dual-Use Coalition — September 20, 2006
- FIRM — August 29, 2006
- PPGA — September 12, 2006



Ms. Heidi Kirrmaier
Vice President, Regulatory
2500, 330-5th Ave S.W.
Calgary, AB T2P 0L4

August 15, 2006,

Re: AESO 2007 Tariff – July 21st Tariff Proposals

Dear Ms. Kirrmaier:

This letter is in response to your solicitation for stakeholder feedback on the July 21st, 2006 tariff proposal. The ADC has reviewed the AESO's most recent tariff proposal and would like to offer the following high level comments.

Pricing of Domestic Rates vs. Export Rates

The AESO has proposed the pricing of domestic rates such as DTS and DOS be higher than export rates, whether firm or opportunity based. This pricing scheme results in a pricing signal that encourages export of electric energy over domestic consumption. The underlying assumption of such a price signal is the cost of transmission to export electric energy is less than to consume the energy within Alberta. It is ADC's position that export rates should be priced above domestic rates since the export energy makes use of the Alberta system in the same manner as domestic users, but also makes use of inter-ties. Additionally, there are other terms of the rates that advantage export over domestic such as contracting terms and time under which the energy is recalled ie. DOS is recallable in 7 minutes while XOS is recallable in 1 hour.

DTS Rates should be Reflective of the Investment Equation

The results of the investment policy show a clear distinction in costs between customers with capacity contracts less than 17 MW and those larger than 17 MW. Since the alignment of the investment policy and rates is one of the aims, the ADC would like to encourage the AESO to align DTS with the resultant investment equation such that DTS recovers a lesser fee for MW contracted above 17 MW. Consistency should be shown between the investment levels and the tariff.

Back up Transmission Service

The back-up or standby service that was initially proposed by the AESO is now no longer part of the proposal due to operational and reliability risks. It is not clear from the latest communication if mitigation measures concerning operations and transmission reliability could be built into the AESO's OPP's that could allow the back-up rate to go ahead. For example, the operation of the system in Fort McMurray could be built into an AESO OPP managing the reliability and operational risks associated with BTS.

In an attempt to control customer migration from DTS to BTS, the AESO could implement the current notice period for customers wishing to leave the system. By effecting this provision, local and POD costs would still be recoverable over a 5 year period and the AESO could incorporate the contract capacity switching into their 10 year Transmission System Plan instead of waiting for the transmission to be built before examining.

The AESO has chosen to relax the qualifying criteria of DOS Term to allow for use of scheduled generator maintenance. It's unclear how a recallable rate can be used as a back-up for generator maintenance. A more thorough discussion of how this rate could be used would be helpful.

Coincident Peak

The ADC fully supports the comments put forth by TransCanada Energy respecting the AESO's proposed move toward the NCP approach. The ADC understands that while the AESO has not found statistical supportive evidence pointing to coincident peak being the cost driver for bulk transmission, this result is also counter-intuitive. Additionally, as pointed out by TransCanada, the AESO has also not provided statistical evidence showing that costs should be recovered on an NCP basis. We would welcome further discussion and study on this rate element.

Thank you for your serious consideration of our comments. We feel that an appropriate next step would be a face to face meeting with your team to discuss the above. Please contact myself at (403) 770-1164 to arrange a convenient time.

Sincerely,

Carrie Haines
Manager – Regulatory, ADC

On behalf of the ADC

CC: Peter Schubert, Dow Chemicals, Vice – President, ADC
Colette Kearl, Valeo Power, Director – Industry Affairs, ADC

ATCO Electric's Comments on 2007 AESO GTA Proposal

ATCO Electric has reviewed the 2007 AESO GTA proposal and has comments in the following areas:

Fixed POD Charges

ATCO Electric believes that the fixed POD charges for small, conventional, unconventional and isolated PODs are unjust and unreasonable, and are not based on the data that is relevant for these PODs. The AESO has determined the fixed component of the POD related cost based on the actual costs for green field projects, none of which was less than 7.5 MW in size. AESO then proposes to apply these fixed POD charges to small conventional, unconventional and isolated PODs. The unconventional PODs are very small in size and they don't even use conventional transformers or substations. The isolated PODs are only notional PODs and again, the fixed costs determined based on larger projects have no relevance to these PODs. The third group of conventional small PODs is also not represented by the analysis used by the AESO for the fixed costs calculations. Further, all small PODs are from a different vintage and the fact that the small POD are absent from the new green field projects is an indication that standards and the design has changed so much that the smaller PODs are not cost effective anymore. It is also an indication that the fixed cost associated with these small PODs is not the same as that associated with the larger projects.

ATCO Electric would request the AESO to mitigate this unfairness for these small PODs through either via cost allocation or rate design. The simplest approach to address this unfairness would be to charge a \$/MW charge for all small PODs of up to 7.5 MW. This would also alleviate the rate shock issue for the small POD customers.

An approach to provide a just and reasonable rate to unconventional and isolated PODs would be to provide them with a station service credit equal to the fixed POD charges as these PODs don't incur the fixed costs equivalent to the large PODs that were analyzed.

Bulk System Cost Allocation

ATCO Electric believes that the Bulk system is planned to meet system load under numerous conditions. These conditions includes loads in summer and winter at peak and off peak hours, various generation patterns and contingencies, extreme hydro conditions, unit turn around and low system load conditions. The POD peak demand is not a good representative of the system loading conditions that are used for the Bulk system planning purposes. In ATCO Electric's view, annual energy is a more appropriate representative of these loading conditions as these conditions happen over several hours and are distributed throughout the year. As such, energy should be used for the recovery of costs associated with the Bulk system.



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September 19, 2006

Via e-mail: john.martin@aeso.ca

John Martin, P.Eng.
Manager, Regulatory Affairs; Market & Strategic Initiatives
AESO - Alberta Electric System Operator
Calgary Place
2500, 330 - 5th Avenue S.W.
Calgary Alberta T2P 0L4

Dear Mr. Martin, P.Eng.,

Re: Dual Use Coalition Comments on July 21, 2006 Stakeholder Update

The Dual-Use Coalition (formerly the COS Coalition) appreciates the opportunity to provide comments on the draft submissions provided on July 21, 2006. Please note that not all of the members of the Dual-Use Coalition have had the opportunity to review these comments and hence we appreciate if you would view them as preliminary.

Primary Service Credit, DRAFT Section 4 — 2007 Rate Design, Page 1 of 2

The Dual-Use Coalition directionally supports the proposed Primary Service Credit formula that links the level of credit to the contribution policy as outlined in the customer contribution policy study analysis.

The Dual-Use Coalition understands that the AESO is not proposing any changes to the PSC eligibility criteria for dual-use customers and supports this position.

Standby or Backup Rate, DRAFT Section 4 — 2007 Rate Design, Page 13 of 2

The Dual-Use Coalition submits that eligibility for a stand-by or back-up rate should be limited to dual-use customers, who collectively have contracted for about 500 MW of DTS. This change could eliminate the AESO's operations and reliability group's concerns with the proposed BTS by significantly limiting the quantum of load that could migrate to the BTS rate.

As discussed, further consultation is planned between the AESO and dual-use customers on this issue, which is appreciated by the Dual-Use Coalition.

Demand Opportunity Service Rates, DRAFT Section 4 — 2007 Rate Design, Page 15 of 2

The Dual-Use Coalition directionally supports modifications to the eligibility criteria to allow DOS to be used for planned generation outages for dual-use customers. The Dual-Use Coalition recognizes that this service should not be entirely cost based.

The Dual-Use Coalition is concerned that dual-use customers have increased their DTS contract capacity in response the change in DOS eligibility criteria that disallowed DOS to be used for planned generation outages for dual-use customers by the former Transmission Administrator. It is requested that the AESO give consideration to allowing dual-use customers who have contracted for DTS for planned outages the opportunity to reduce their DTS contract capacity after a shorter notice period than the current five year notice provision.

Transmission Cost Causation, DRAFT Section 4 — 2007 Rate Design, Page 13 of 2

The Dual-Use Coalition notes that the AESO's planners take into consideration diversity provided by dual-use customers and do not plan transmission capacity up to the sum of all DTS contract capacities. It therefore seems inappropriate for all bulk system costs to be collected based on billing capacity, which for dual-use customers, is typically their DTS contract capacity. Further, the Dual-Use Coalition questions the AESO's determination that bulk system stress can be expected to occur at any time, including during off-peak hours, to the extent that bulk system expansions would be planned based on off-peak loads.

The Dual-Use Coalition requests that the AESO reconsider its determination that all bulk system demand related costs should be recovered based on billing capacity instead of measured demand or on-peak energy. Further, the Dual-Use Coalition is concerned that the transition from a system coincident peak charge to a billing capacity charge will result in significant, and unwarranted, DTS rate increases for dual-use customers.

If you require any additional information, please contact the undersigned at 403-869-6200 or dale.hildebrand@desiderataenergy.com.

Sincerely,

Desiderata Energy Consulting Inc.

W. Dale Hildebrand, P.Eng., M.B.A.
President

copy: Dual-Use Coalition members

**FIRM's Comments on
AESO 2007 Tariff Consultations**

1. Recovery of Bulk System Costs

The AESO proposes to classify bulk system costs 81.5% to demand and recover about 80.7% of the costs so classified based on the billing capacity (POD NCP) and about 19.3% on energy. The 19.3% energy recovery reflects diversity between AIS peak at the time of bulk system maximum stress on a weighted basis. [Section 4 P8 of 27] In effect, about 65.7% of bulk system costs are proposed to be recovered based on POD NCP.

The facts appear to be as follows:

a) The AESO system peak is about 86% of the POD NCP peak on a monthly basis. This shows there isn't perfect coincidence between system peaks and POD NCPs on a monthly basis

b) The AESO system peak is about 80.7% at the time of the weighted average bulk system peak

c) On average, bulk lines were at 61% of their annual peak at the single hour of annual AESO system peak.

(c) Load on bulk lines had the following correlation with system load:

- strong negative correlation: 1 line (1%)
- moderate negative correlation: 4 lines (5%)
- weak negative correlation: 12 lines (15%)
- no correlation: 15 lines (19%)
- weak positive correlation: 27 lines (34%)
- moderate positive correlation: 16 lines (20%)
- strong positive correlation: 5 lines (6%)

(d) When weighted by line length, the average correlation between bulk line load and system load was 0.09, which would generally be considered "no correlation".

It is noted from the foregoing that only about 54% of the bulk system lines show even a modicum of positive correlation with system peaks ranging from weak positive correlation (34%) to strong positive correlation (6%). All other lines show no correlation (19%) to strong negative correlation (1%). On average, bulk lines were at 61% of their annual peak at the single hour of annual AESO system peak.

Two points are worth noting. First, from the point of view of cost recovery and price signals, the average bulk line loading at the time of AESO system peak is a more relevant measure than the AESO peak when Bulk system lines tend to peak on average. This is because annual peaks for different bulk system lines occur at different times. It would appear to be reasonable to recover no more than 61% of bulk system demand costs based on the annual AESO peak.

The second point to note is that the AESO appears to have ignored the degree of coincidence between AESO system peaks and POD NCP peaks. Since cost recovery is based on POD NCP peaks it would be appropriate to recognize the diversity between system peaks and POD NCP peaks. Ideally this recognition should be carried out on a monthly basis. The correlation between POD NCP and system peaks, although variable by month, is about 86%.

The foregoing point to the inference, any recovery of bulk system costs based on POD NCP must reflect a much smaller demand component as opposed to the 65.7% proposed by the AESO. A rough calculation indicates the demand component of bulk system costs should be lower than 50%. [$61\% * 86\% * 81.5\% = 42.75\%$]. It is suggested that AESO reconsider its proposed recovery of 65.7% of bulk system demand costs based on POD NCP.

2. Recovery of Local System Costs

The AESO proposes to classify 17.6% of local system costs as energy related, taking into account the energy optimization costs related to a minimum system. 82.4% of local system costs would be recovered on the basis of billing capacity. However, there is no recognition of any diversity between billing capacity at the POD and at the local system. Many local system lines appear to be looped and this reinforces the need to recognize a diversity factor in the design of local system charges.

It is suggested that the AESO reconsider its proposed demand energy classification of local system costs having regard to demand diversity between the local system and POD NCPs. In our view recognition of diversity between POD NCPs and the local system would warrant a higher energy classification than proposed by the AESO.

3. Isolated Systems

The cost of service treatment of isolated systems should reflect fair allocation of these legislated costs to all Alberta transmission customers. However, under the present cost of service treatment isolated PODs, which in many instances are very small PODs, are treated the same as any other POD, attracting full fixed POD charges. As a result the non isolated customers of ATCO Electric Disco end up picking up a higher proportion of recoveries related to isolated systems compared with other transmission users. In our view this is an unfair recovery of isolated system costs. In this regard two possible remedies are suggested.

The first remedy involves the classification of isolated system costs. The AESO proposes to include isolated system costs which include a large element of variable fuel costs, as part of fixed wires costs. In order to reflect cost causation, there is merit in first classifying the energy related costs of isolated systems as energy and the fixed costs as demand before all remaining wires costs are classified to energy and demand.

The second remedy involves redesigning the fixed POD charges for isolated systems. The principle to be borne in mind is that the all transmission customers should bear a fair (proportionate) share of isolated system costs. A high fixed POD charge for each isolated

system POD results in ATCO Electric customers bearing a disproportionate share of cost recovery. One possibility may be treatment of all isolated PODs collectively as one POD for purposes of levying the fixed POD charge.

It is suggested that the AESO give consideration to the cost of service and rate design treatment of isolated system costs so that any legislated subsidies related to isolated systems are taxed fairly to all customers of the AESO.

4. PODs less than Minimum Size

The minimum size POD proposed by AESO appears to be 7.5 MW based on the substation sample. [July 21, 2006 Draft Section 4 P11;L44] However, there are number of smaller PODs connected to the system. Recovery of costs for small PODs based on the cost of a minimum size POD of 7.5MW appears unfair and does not appear to reflect cost causation.

It is suggested the AESO look into the possibility of using the proportionate cost method to levy POD fixed charges for small PODs less than 7.5 MW. For example a POD with a capacity of 2 MW would be charged a POD fixed charge of $2/7.5$ times the fixed charge.

The AESO's proposal is to have an investment policy that is consistent with rates. Accordingly, if the proportionate cost method is used to levy POD fixed charges for small PODs the same method should be used to assess company investment with respect to the small PODs.



PPGA PROPOSED MODIFICATION OF THE AESO 2007 GTA RATE DESIGN, SEPTEMBER 12, 2006

INTRODUCTION

This representation to the AESO is made on behalf of the Pipeline Power Group and Associates (PPGA), an industry association representing the following companies: TransMountain Pipelines, Corridor Pipeline, Express Pipeline, Rangeland Pipelines and other industrial companies with similar interests.

The original presentation of this material was discussed during several stakeholder meetings with the AESO during the months of July and August 2006. This report summarizes the outcome of those presentations and addresses concerns expressed by the AESO.

The PPGA customers are perplexed and dissatisfied by implementation of the POD charge that resulted in rate increases in 2006 at some locations ranging from 200-400%. Due to the arbitrary and unfounded discriminatory nature of this tariff, the PPGA customers believe that changes to the rates must be made immediately.

Despite the AESO studying and benchmarking other utility rate design, the AESO has stated that they are not aware of any POD allocations by other utilities in North America.

To the best of the PPGA's knowledge, the implementation of a high cost POD charge is unprecedented across power utilities in North America. The PPGA is aware of some local POD type charges at certain facilities in the U.S. Although the details of these Agreements are confidential; it is important to note that the magnitude of these U.S. POD charges range from \$300-5,000/ month, based on either fixed or demand based billing.

Although it would be the preference of PPGA customers to eliminate all POD charges, the PPGA believes this may not be acceptable. Rather than intervene for complete removal of all POD charges, the PPGA is proposing an alternative more cooperative approach for POD rate design. Therefore, the PPGA has worked with the proposed AESO POD charge and modified it to present a more fair and sustainable tariff.

The PPGA concur with the concept of cost/causation and are prepared to pay their fair share of the Transmission costs. This willingness to pay is based on costs supported by sound, proven data. The 2006 and the proposed 2007 transmission rate levels were not only unreasonable but also unsupported by sound data.

The PPGA has entered into discussions with several other user groups who "in general" support the process, logic and general results of the PPGA POD rate design.



1.0 SAMPLE DATA

One of the first concerns raised by the PPGA is the adequacy of the sample data used in the development of the redesigned rates. There are 403 POD sites included in the data the AESO filed on June 21, 2006. In designing the DTS rate, the AESO concluded that a sample of 30 Greenfield sites best represents the current facility cost function for new POD's. Additionally, the AESO's methodology assumes that the best method to create a POD charge for all 403 sites is to use only the Greenfield sample data (30 data points). However, the Greenfield sample data and the "All POD" data have materially different distribution patterns, as highlighted in Table 1.

Table 1: POD SAMPLE DATA

	All PODS		30 Greenfield PODS after 1999	
	<i>Number</i>	<i>% of total</i>	<i>Number</i>	<i>% of sample</i>
Less than 7.5MW	114	28%	0	0%
7.5MW to 17MW	135	33%	16	53%
Greater than 17MW	154	38%	14	47%
	403	100%	30	100%

The above comparison of all PODs with the Greenfield POD post 1999 sample shows that the Greenfield data is not representative of all load categories. No Greenfield sites less than 7.5 MW's have been constructed since 1999 (Loads below 7.5 MW are usually served at distribution voltages).

In the "all PODs" data, sites below 7.5 MW included a significant number of sites built more than 20 years ago and some more than 40 years ago. These older PODs are fully depreciated. Dramatically increasing rates to these smaller fully depreciated PODs is unfair. Extrapolating an investment cost function from larger sites, at today's cost, and applying this to smaller PODS is discriminatory. The investment decision for smaller POD's to be connected at transmission voltage was made under the prevailing tariffs and investment policies at the time of construction of the PODs. It is unfair and discriminatory to these DTS customers to re-structure and re-price these agreements, when these customers are not able to take action to reduce their charges.



Essentially, the PPGA agrees with the AESO in its statement made in the July 21 paper:

“The AESO therefore concludes that the existing small load services would exhibit a cost function different from and lower than the average cost function for larger load services, if data was available for such interconnections. The AESO also expects that such costs would be closer to a minimum cost function than an average cost function.”

2.0 INTEGRATION OF SAMPLE DATA INTO RATE DESIGN

However, recognizing that comprehensive cost data is difficult to obtain, the rate design should attempt to mitigate inadequacies in the sample data and consider fairness and rate shock and non-discriminatory principles in rate design.

Given the limitations of the data, (very poor R^2 , significant concern of scatter) the PPGA may be supportive of the AESO’s methodology, given minor modifications to the design process to address the discriminatory and rate impacts of smaller load customers.

Given the data above as the best available, it appears that there are three natural clusters of load:

1. **Below 7.5 MW POD’s:** not represented in the Greenfield data. No data points.
2. **7.5 MW to 17 MW PODs:** currently the smaller load category. Inherently these substations are overbuilt at 138 to 144 kV as mandated by the AESO to achieve system benefits such as lower losses, fewer operational spares and procurement advantages. The small load customer incurs higher capital costs and does not realize or receive credit for the system benefits achieved by forgoing supply at a more appropriate fit-for-purpose design of 69 kV.
3. **Greater than 17 MW load category:** where the average cost curve is more representative than the smaller loads.



3.0 RATE DESIGN

The AESO proposes a single cost function that is applicable, on average, for all projects. The PPGA agrees with the AESO that some of the shortfalls of this analysis are:

1. No single function based on all data or a function based on a subset of project data is statistically robust.
2. There is significant scatter around the average cost functions
3. Modifying the average cost function to represent minimum costs better represents small project costs as this avoids attributing significant costs to projects that were not incurred

While the PPGA may support the AESO's *unique* methodology, the PPGA does not agree with one aspect of the methodology: adjusting the average cost function to a minimum cost function. The AESO scales both the y-intercept and the slope of the average cost function. (See Chart 1: The yellow line scaled to the red line). This method overstates the cost of smaller projects and understates the cost of larger projects. The PPGA does not feel it is appropriate to change the investment function slope since:

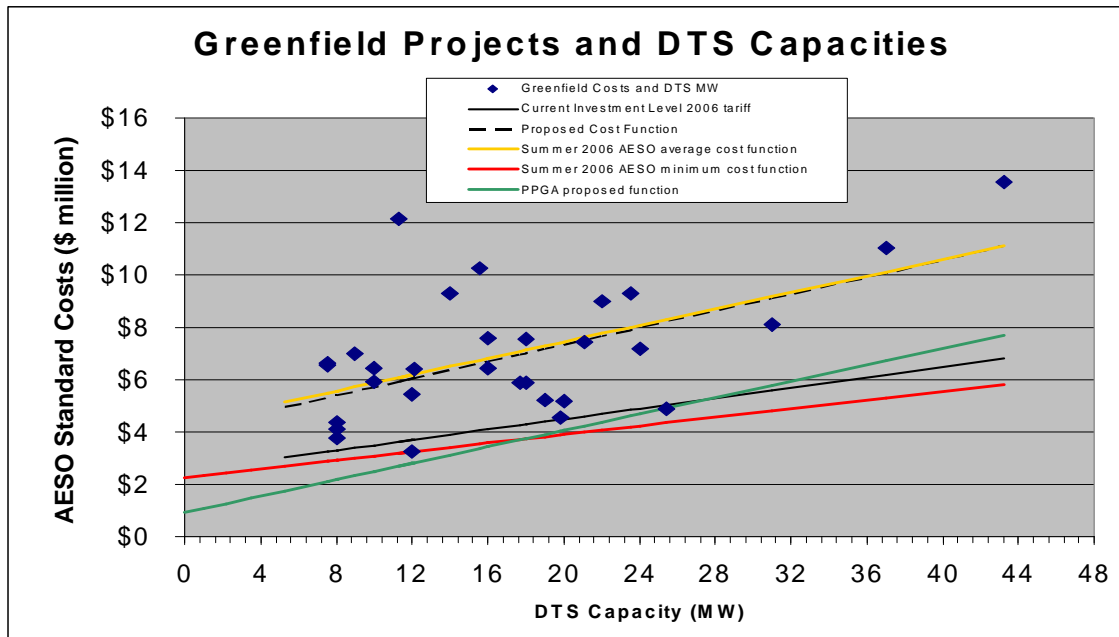
1. The slope is the “best fit” line for determining how costs increase as POD capacity grows.
2. The slope is the “best fit” for the “noise” of the transmission line lengths associated with the geographic location and other cost drivers associated with individual POD's. The transmission line cost is correlated to line length as demonstrated by the AESO's July/06 report. Retaining this slope for the investment function seems to be the only technique that will reflect the “best fit” variation in transmission line and other costs.

The minimum Y-intercept should be created by maintaining the slope of the average cost function and simply moving the curve downwards to a level that includes the two lowest cost Greenfield PODs (see Chart 1 green line). This method will create a minimum Y-intercept that maintains the integrity of the “best fit” regression line.

Applying PPGA's methodology to derive the minimum function from the average function results in a Y-intercept of \$0.919 million and maintains the average cost slope of \$0.157 million/MW, (see Chart 1 green line).



Chart 1: Modifying the average cost function to represent the minimum cost function



From this minimum function, the AESO methodology is applied (see Appendix 1) resulting in a POD charge as described below and represented graphically in Chart 2.

Point of delivery charge of:

- (a) \$2,500 /MW/month of billing capacity for billing capacity at or below 7.5 MW (Note: for existing small load transmission customers a lower rate would apply – see section 4, Existing Customer Discount).
- (b) for loads greater than 7.5MW:
 - (i) \$5,200 / month multiplied by the substation fraction, plus
 - (ii) \$1,800/MW/month of billing capacity for billing capacity between 7.5MW and 17MW
 - (iii) \$1,000/MW/month of billing capacity for billing capacity above 17MW

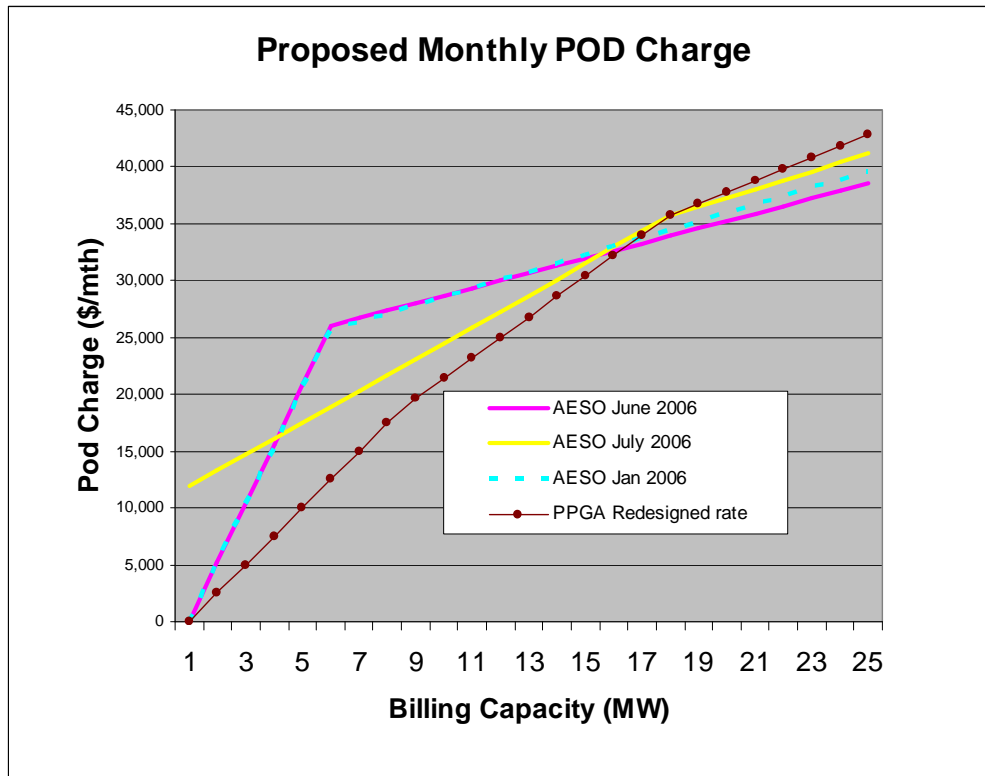


Chart 2: The proposed monthly POD charge proposed by the PPGA along with earlier AESO proposals

4.0 EXISTING SMALL TRANSMISSION CUSTOMER DISCOUNT

All DTS customer facilities under 7.5 MW were constructed prior to 1999. Certain facilities represented by the PPGA were constructed as far back as 50 years ago. The PPGA does not believe it was the intent of the AESO to penalize some small load “T” customers who have contributed to rate base and paid tariffs for several decades.

For some existing facilities, the book value of the sites is almost fully depreciated. The central issue for these sites is capital maintenance costs required to maintain service. To address the cost/ causation of maintenance costs, the AESO needs to create a new cost/ causation study. The existing cost/ causation study does not directly address maintenance costs and simply assumes that maintenance costs follow capital expenditures (with no supporting analysis).

Creating a new cost/ causation study will be time consuming , costly, and may not provide any meaningful results if the TFO data files are not easily mined. In the interest of time,



efficiency and fairness, the PPGA believes that the small load, transmission voltage customers should not be penalized with the existing substantial and unfair POD charges. These customers chose transmission service over distribution based upon the capital and operating costs in place at the time of construction.

Due to inadequate data and analysis, the PPGA believes that two principles should guide the rates to the existing less than 7.5 MW customer group,

- 1.) A rate increase from the 2005 tariff should not be higher than the average DTS increase of 77.6% (reference for the average DTS increase – AESO letter to the AEUB, dated Nov. 14, 2005).
- 2.) The slope of the POD rate to this customer group should not be higher than the average cost function – or \$1000/MW/Month.

Therefore, the PPGA proposes a further discount to the less than 7.5 MW group of \$1500/MW/Month. The final proposed DTS POD charge to customers less than 7.5 MW, in service prior to the implementation of the 2007 tariff would be:

Point of delivery charge of:

- (a) \$1,000 /MW/month of billing capacity for billing capacity at or below 7.5 MW

5.0 FAIRNESS OF RATES

The PPGA believe that rates should be “reasonable” and approximately equal from one load size (rate class) to another both from a percentage increase and a \$/ MWh basis.

The PPGA proposed rate function for new customers, results in similar increases for all MW rate classes given the same load factor.

For example, the rate increases to new customers calculated from the PPGA proposed 2007 rate compared to the 2005 AESO tariff, range from about 84-98 % and the increase on a per unit basis ranges from about \$8.7-\$9.3 / MWh. These rates vary about 10% between load rate classes when using a load factor of 75%.

Conversely, the 2007 AESO proposed tariff yields increases of 411% for 1 MW customers, 151% for 4 MW customers and 62% for 25 MW customers at the 75% load factor level. The impact of these increases is about \$24/MWh for one MW load and only about \$7.6/MWh for a 25 MW load.

Therefore, the PPGA proposed tariff is fair and less discriminatory than the proposed AESO tariffs.



6.0 CONCLUSION

Despite the problems with the data used in the design of AESO's rates, the PPGA is supportive of the overall methodology as long as the adjustment to the determination of the minimum cost function is made and the less than 7.5MW load block receives the treatment proposed in this submission.

The PPGA proposed rate achieves a balance between non-discriminatory collection of revenues and fair cost allocations. The PPGA believes it is expedient to use this data and analysis described in this paper rather than create another cost causation study that will be costly and time consuming. Furthermore, the results of a new study may or may not provide superior data that is statistically sound.

The PPGA supports the notion of future studies to better determine the cost/ causation relationship of load under 7.5 MW, but only if does not hold up the replacement of the existing and proposed rates with more fair allocations such as the one proposed by the PPGA in this paper. If future studies show that these costs still do not properly, reflect the cost/causation relationship than the cost functions generated from this analysis should be adjusted to reflect it.

The PPGA would be willing to discuss and clarify its position with interested parties or stakeholders. For more information, please contact Jamie Shand, Ed de Palezieux or Colin Carlsen at the Current Solutions office in Calgary at 403-233-7037 or via email at csiadmin@currentsolutions.ca.



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APPENDIX 1: CALCULATION OF THE POD CHARGE

AESO 2006-07-21 proposal creates a minimum intercept by multiplying the investment y-intercept **and** slope by 0.4885. As discussed in the main body of this report, PPGA only scales the y-intercept retaining the slope of the cost function, resulting in a y-intercept of \$0.919 million and a slope of \$0.157 million/MW. The minimum intercept approach of the AESO and the PPGA are displayed in Chart 3 below.

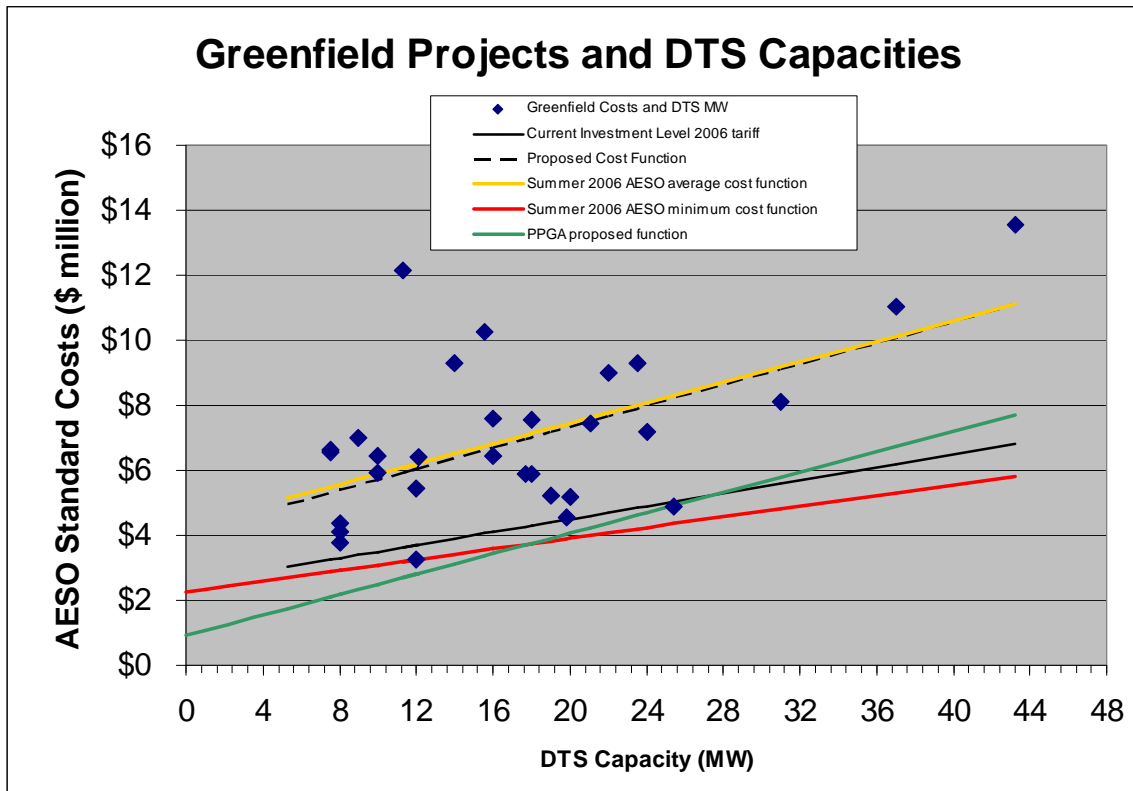


Chart 3: Derivation of the minimum function

The minimum cost function methodology does not affect large customers, as the slope of \$0.157 million/MW is retained for the larger customer base. Customers over 17 MW are subject to the average cost curve. Therefore, the minimum cost function is only important in the analysis to customers under 17 MW.

For customers between 7.5 and 17 MW, the chart above shows that the PPGA minimum capital costs for this load is \$2 to \$3.5 million. This appears to be a reasonable estimate of minimum POD costs.



Using the AESO’s methodology, the PPGA has estimated the full investment function and resulting POD costs using in the following steps.

1.) The “all POD” average project cost calculated for a POD of 17.2 MW is \$7.015 million. Using this data and solving for the slope of the function between 7.5MW and 17 MW results in the following:

$$\$7.015\text{million} = \$0.919\text{million} + (X \text{ million} \times 17.2 \text{ MW})$$

$$X = \$0.354 \text{ million/MW}$$

The minimum investment function for this load range is therefore:

$$\text{Min } fx = \$0.919 \text{ million} + \$0.354 \text{ million/MW} \times \text{DTS capacity}$$

2.) Despite the poor statistical correlation (poor fit low R^2) for load greater than 17 MWs, the average cost curve best represents these costs, with the average slope of \$0.157 million /MW, resulting in the full cost function:

$$\text{Cost} = \$0.919 \text{ million}$$

$$+ (\$0.354 \text{ million/MW} \times \text{first 17 MW of DTS Capacity})$$

$$+ (\$0.157 \text{ million/MW} \times \text{DTS Capacity above 17MW})$$

3.) For loads less than 7.5MW only a demand charge would apply, using the same methodology currently in place in 2006 for customers below five MW. The PPGA believes that a 7.5 MW cut-off is more appropriate than the previously suggested rather arbitrary 5 MW level. Since the 7.5MW level is the largest size of customer not included in the Greenfield data. The slope of the minimum function, assuming zero customer charge can be calculated as follows

$$\$0.919 \text{ million} + \$0.354 \text{ million} \times 7.5 \text{ MW} = \text{SLOPE} \times 7.5 \text{ MW}$$

$$\text{SLOPE} = \$0.4765 \text{ million /MW}$$

Therefore, for load in the 0 MW to 7.5 MW range, only a demand related cost of \$0.4675 /MW is applicable. This is a similar methodology to the grandfathered rate proposed by the AESO during earlier stakeholder consultations.

4.) The PPGA proposal for the minimum cost function for all loads is:

$$\text{Cost} = \$0.4765 \text{ million /MW} \times \text{first 7.5 MW of DTS capacity}$$

$$+ (\$0.919\text{million per POD with DTS capacity above 7.5MW})$$

$$+ (\$0.354 \text{ million/MW} \times \text{first 17 MW of DTS Capacity})$$

$$+ (\$0.157 \text{ million/MW} \times \text{DTS Capacity above 17MW})$$



5.) The cost function is then translated into the POD rate function using the methodology outlined in AESO's July 06 paper, resulting in the final POD charge of:

- (a) \$2,500 /MW/month of billing capacity for billing capacity below 7.5MW
- (b) for load greater than 7.5MW:
 - (i) \$5,200 / month multiplied by the substation fraction, plus
 - (ii) \$1,800/MW/month of billing capacity for billing capacity between 7.5MW and 17MW
 - (iii) \$1,000/MW/month of billing capacity for billing capacity above 17MW



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APPENDIX 2: CAPITAL CONTRIBUTION

The PPGA utilized the AESO’s July 06 methodology to derive the capital function resulting from the PPGA’s minimum intercept analysis. The minimum cost function was scaled to ensure that 80% of the Greenfield projects (as directed by the EUB) would not require a capital contribution. The proposed PPGA function, shown in chart 4, is displayed below.

Capital Contribution per contract year (maximum 20 year period)

$$\begin{aligned}
 &= \$66,000 \\
 &+ \$25,000 \times \text{DTS Capacity less than 17MW} \\
 &+ \$11,000 \times \text{DTS capacity above 17MW}
 \end{aligned}$$

The PPGA investment function is less generous to customers below 11 MW than the AESO’s existing proposal. The PPGA proposal offers customers over 11 MW an increased contribution, as shown in Chart 4.

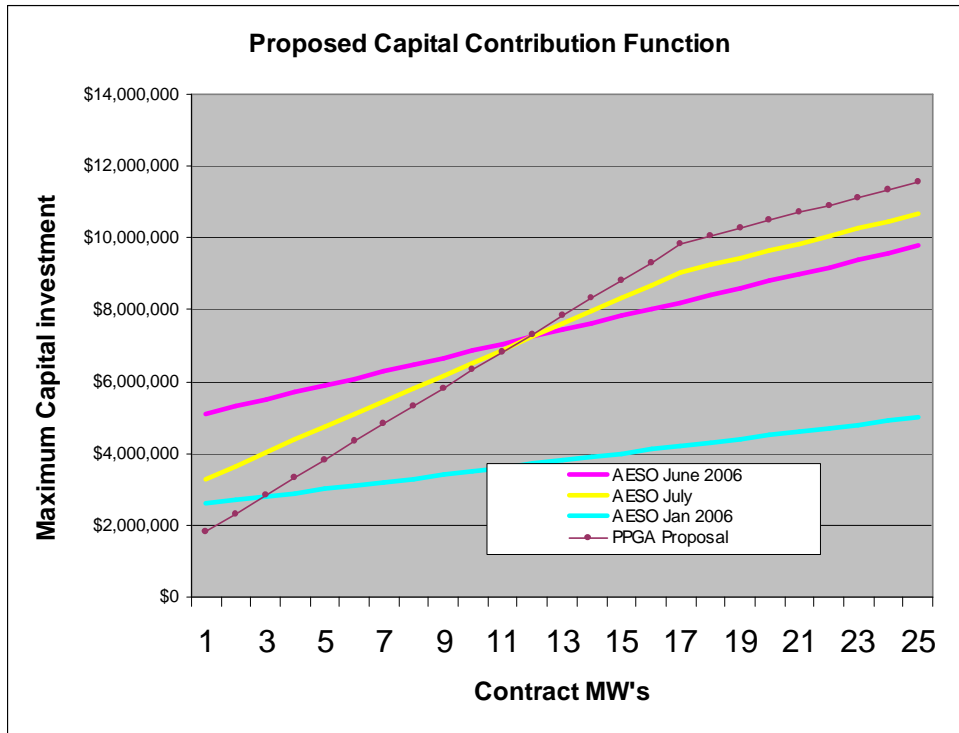


Chart 4: Proposed investment



The PPGA believes that the reduced POD rate charged to customers below 7.5 MW should not influence the capital contribution to these customers for two reasons:

- 1.) The lower or minimal POD charge to these smaller customers is more applicable for this rate class due to the unique historical nature and circumstances of this load. Future customers in this load bracket will be minimal and only built under special or unique circumstances.
- 2.) The POD data analysis does not recognize that smaller load transmission level customers rarely require an interconnection at 138 kV. However, the TFO's in Alberta have adopted 138 kV as the minimum standard transmission voltage. While this standard saves the system funds by minimizing parts inventories and system losses as well as reducing operating, and maintenance charges, smaller customers pay higher costs for interconnections. It is estimated by the PPGA that smaller load transmission customers pay up to 30% more for their interconnections than would be necessary if they could have connected at a "fit for purpose" lower voltage level, such as 50 or 69 kV. Therefore, smaller customers should be adequately compensated for this system value.