APPLICATION NO. 1485517

ALBERTA ELECTRIC SYSTEM OPERATOR (AESO)

2007 GENERAL TARIFF APPLICATION

DUAL USE CUSTOMERS

POD CHARGES AND PRIMARY SERVICE CREDIT ARGUMENT

June 21, 2007

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Introduction and Recommendation Summary

In this proceeding the Dual-Use Customers ("the DUC") have focused their efforts on trying to enhance cost causation for the Alberta Electric System Operator's ("AESO's) Demand Transmission Service ("DTS") and Primary Service Credit ("PSC") rate design by recommending a proper alignment between the AESO's interconnection cost function, Point of Delivery ("POD") charges, PSC and maximum investment levels. The DUC notes that it is making its recommendations and submits that its proposals are just and reasonable even though its proposed POD charges and proposed PSC levels will result in a 29% price increase for DUC member companies all of whom are PSC eligible.[1]

In summary, the DUC has made and will address below in accordance with the Board's proposed argument outline the following recommendations for the Board's consideration:

1. The AESO's recommended interconnection cost function should be approved up to 40 MW for 2007 costs, and should be modified to have an incremental cost of $30,000/MW for interconnections above 40 MW.
2. The DTS POD Charges should reflect the recommended interconnection cost function by adjusting the rate design and adding a fourth charge for Billing Capacity above 40 MW.
3. The AESO's contribution policy should also reflect the recommend interconnection cost function by adjusting the maximum investment amounts, including lower maximum investment amounts for services with DTS Contract Capacity over 40 MW.
4. The maximum investment amounts should be increased by 5% to reflect inflation from 2007 to the time period that the tariff will likely be in effect over late 2007, 2008 and 2009.
5. The PSC should be adjusted to be 55% of the POD Charges for customers who own their own substations, except for Billing Capacity over 40 MW where the PSC should equal the POD charge.
6. Isolated generation PODs should not be eligible for the PSC.
7. Bulk transmission costs for non-standby usage should be recovered using a 12 CP rate design.
8. Local transmission costs for non-standby usage should be recovered using a monthly NCP rate design (maximum measured demand without ratchet or contract capacities applied).

[1] Ex. 229, p. 41, POD + PSC = $1.99 million under the 2006 DTS tariff, $2.57 million under the proposed 2007 tariff with the DUC proposed adjustments, for an overall 29% increase to PSC eligible customers.

9. POD transmission costs for non-standby usage should be recovered using a monthly NCP, demand ratchet and contract capacities rate design.

10. The Payment in Lieu of Notice should be the set to equal the present value of the last 24 months of DTS bulk and local system charges prior to the customer exiting the system.

The AESO responded to directions from the Board in Decisions 2005-096 and 2005-132 by preparing an interconnection cost function and used this function to prepare POD charges and maximum investment levels. The DUC submits that the Board correctly anticipated that the interconnection cost function would exhibit significant economies of scale; that is, on an incremental $/MW basis, large PODs should have a lower cost than small PODs. Unfortunately, the AESO was not able to obtain recent cost data to support the economies of scale present for PODs over 40 MW, even though additional data from the Transmission Cost Causation Study (“TCCS”) does suggest that economies of scale are present above 40 MW.

For the most part, the DUC accepts the AESO’s methodology and submits that the data used, particularly as adjusted and enhanced by the DUC’s evidence, is adequate and appropriate for ratemaking purposes.

The DUC’s rate design adjustments and recommendations are enhancements to the AESO’s application and have been made to better reflect cost causation. The DUC provided the Board with empirical evidence, supported by expert testimony, which shows that the anticipated economies of scale are present for PODs above 40 MW. Indeed, the economies of scale above 40 MW have been even more pronounced in recent years due to the AESO’s change in policy which has limited standard facilities to one transmission line, one breaker and one transformer.

The PPGA and the CCA/PICA have also provided the Board with proposed adjustments to the POD and PSC tariff components. The following table presents the DUC’s understanding of the relevant recommendations of the parties:[2]

[2] AESO Proposal: Ex. 005, section 4 of Application, p. 21 & 51 & Ex. 007, section 6 of Application, p. 31
DUC Proposal: Ex. 229, p. 22, 29 & 37
PPGA Proposal: Ex. 239, p. 15, 17 & 21
CCA/PICA Proposal: Ex 225, p. 7-10 & Schedule 3

POD Charges		**AESO Proposal**	**DUC Proposal**	**PPGA Proposal**	**PPGA Alternate Proposal**	**CCA/PICA Proposal**
Fixed	($/month x SF)	4,762	4,762	4,725	5,833	7,083
0-7.5 MW	($/MW/Month x SF)	3,129	3,435	1,447	1,735 (1)	2,438
7.5 - 40 MW	($/MW/Month)	776	852	1,447	1,024 (1)	912
40 + MW	($/MW/Month)	776	166	1,447	1,024	912

PSC		**AESO Proposal**	**DUC Proposal**	**PPGA Proposal**	**PPGA Alternate Proposal**	**CCA/PICA Proposal (3)**
Fixed	($/month x SF)	1,905	2,619			2,833
0-7.5 MW	($/MW/Month x SF)	1,252	1,889	720 (2)	721 (2) (1)	975
7.5 - 40 MW	($/MW/Month)	310	469	720	720 (1)	365
40 + MW	($/MW/Month)	310	166	720	720	365

Max. Investment Levels		**AESO Proposal**	**DUC Proposal (4)**	**PPGA Proposal**	**PPGA Alternate Proposal**	**CCA/PICA Proposal (5)**
Fixed	($/year)	54,500	57,225	54,500	54,500 (1)	54,500
0-7.5 MW	($/MW/year)	35,800	37,590	35,800	35,800 (1)	35,800
7.5 - 40 MW	($/MW/year)	8,900	9,345	8,900	8,900	8,900
40 + MW	($/MW/year)	8,900	1,785	8,900	8,900	8,900

Notes:
(1) PPGA Alternate Proposal is a breakpoint at 17 MW
(2) PPGA proposal is $720/MW/month, not multiplied by the substation fraction
(3) The DUC assumes the CCA/PICA supports the AESO's determination that the PSC should be 40% of the POD Charges. The CCA/PICA did not respond fully to DUC.CCA/PICA-3, Ex. 297
(4) DUC suggests in argument that the maximum investment levels should be increased by 5% to reflect inflation to 2008 / 2009
(5) The DUC assumes the CCA/PICA supports the AESO's maxmimum investment levels

As noted, the DUC generally supports the AESO's methodology for determining rates up to 40 MW of Billing Capacity. However, the DUC suggests that in order to reflect cost causation and the significant economies of scale present for larger PODs, the rate components should be adjusted for any consumption over 40 MW of Billing Capacity.

The PPGA does not support the AESO's approach and suggests that the AESO's data is not good enough to justify modifications to the AESO's rates in light of the rate increases small PODs have experienced from the AESO's 2005 tariff to the AESO's 2006 tariff.

The CCA/PICA suggest that the number of PODs that have radial lines serving them is justification to alter the interconnection cost function, which will increase the POD charges to larger PODs.

The DUC submits that the DUC's proposed adjustments are warranted in light of the Board's primary rate criterion of cost causation. The DUC's evidence shows that the rate impacts of the DUC proposed rate adjustments are not significant and should not be construed as rate shock. The DUC submits that its recommendations are appropriate, in the public interest, appropriately satisfy rate design criteria, and will improve the fairness of the AESO's tariff. The DUC addresses each of these rate components and other aspects of the AESO's application below in accordance with the Board's argument outline.

1. Stakeholder Consultation and Process Matters

The DUC appreciates the efforts expended by the AESO during its stakeholder consultation process.[3] As noted in the DUC's comments to the Chairman, the DUC submits that more in-depth discussions with stakeholder representatives involved in the regulatory processes may provide a greater opportunity for issues to be resolved prior to a formal Board hearing.

3. Phase II

3.3 Transmission Cost Causation (Transmission Cost Causation Update - Appendix C & D)

The DUC submits that the price increases from 2005 to 2007, which appear to be the PPGA's principal concern,[4] are primarily a function of the TCCS, which determined that there is a significant fixed POD cost component.

The PPGA chose not to address the TCCS or the 2006 Transmission Cost Causation Update ("TCCU") as presented by the AESO in Appendix C[5] of its application. It was the TCCS (and the TCCU) that determined that PODs had a high level of fixed costs and that lead the AESO to propose a separate POD charge with a large fixed charge component ($21,899/month approved in the 2006 tariff DTS rate). And it is the large fixed POD charge component that results in the large price increases for small sized PODs.[6]

Two of the PPGA witnesses have extensive cost of service expertise.[7] However, the PPGA led no evidence to suggest that the quantum of costs allocated to PODs in the TCCS or the TCCU were too high. Instead, the PPGA focused its intervention on the POD rate design by suggesting that the evidence presented by the AESO and others was not good enough and shouldn't be relied on.

The PPGA says that PPGA member PODs have been heavily cross-subsidizing larger PODs under the current tariff.[8] This statement is unsupported by the record. The statement assumes that revenues and costs were properly aligned under the AESO's 2005 tariff, and were improperly aligned under the AESO's 2006 tariff. In fact, unlike the AESO's 2006 tariff, the 2005 tariff did not have the benefit of the AESO's TCCS. Contrary to the PPGA's suggestions, it is far more likely that the 2006 tariff accurately

[3] T. 1372-1377
[4] For example, T. 1462
[5] Ex. 012
[6] Decision 2005-132, p. 4
[7] Ex. 354 & 355
[8] T. 1537/1-3

aligned revenues and costs and that the PPGA members were the ones being subsidized under the 2005 (and earlier) tariffs.

3.4 Demand Transmission Service (DTS) Rate Design

3.4.1 Rate Design Considerations

3.4.1.1 Cost of service criterion (weight, accuracy, time period)

The Board clearly articulated in Decision 2005-096 that cost causation was the primary rate design criteria.[9] The DUC submits that it is clear that there are significant economies of scale in the POD (interconnection) costs and that cost causation demands that the economies of scale be incorporated into the DTS and PSC rate designs.

Even the PPGA admits that there are economies of scale for larger facilities built in the same location as a smaller facility.[10] To simply ignore the economies of scale present is not appropriate.

The DUC submits that the cost causation principle dictates that all components of the rate design need to reflect cost causation. In particular, the DUC submits that each of the following tariff elements needs to be aligned:

1. DTS rate POD charges
2. PSC rates
3. Maximum investment amounts

All three tariff elements can be and should be derived from the interconnection cost function, which reflects cost causation for POD interconnections.

The AESO has proposed that items 1 and 3 should be aligned. The DUC agrees. However, the AESO has not proposed to align the PSC with the POD charges. As discussed in section 3.11.1 PSC Credit methodology (AESO vs. DUC approach) below, in our submission, the principle of cost causation also requires that the PSC should be aligned with the POD charges.

The DUC submits that a fundamental consideration for the design of POD charges should be whether the POD charges are intended to recover costs based on historical cost causation or future cost causation.[11] For most rate designs this question is not relevant as future costs are recovered in the same manner has historical costs. However, for this proceeding, the DUC submits that historical system investments in customer interconnections for large PODs is materially different from the current polices of the AESO. The difference stems from the AESO's current policy of only investing in

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[9] Decision 2005-096, p. 15-16

[10] T. 1475/1-3

[11] T. 1347/12-1348/16

a single transformer for new customer connections, whereas historically in Alberta more than one transformer was provided for larger services.[12]

Notwithstanding the change in the AESO's policies for transformer investment, the evidence in this proceeding shows that the DUC's proposed interconnection cost function is appropriate from both historical and future cost causation perspectives.[13]

It appears that the AESO may be of the view that both historical and future cost causation are the proper basis for rate design. The AESO stated:

> In Decision 2005-096, the EUB considered that the second and third principles would be satisfied by rates which recover costs <u>in the manner in which they are caused</u>. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective, and equitable, and should minimize or eliminate inter-customer subsidies. Cost causation therefore becomes the primary consideration when evaluating a rate design proposal.[14] (underlining added)

However, the AESO was not able to obtain historical cost information for all PODs, and elected to utilize a sample set of PODs from 2000 to 2006 to determine the appropriate interconnection cost function and POD charges. The AESO stated that its proposed interconnection cost function was indicative of cost causation:

> As noted in section 4.2 of this Application, the EUB considered that rates should recover costs in the manner in which they are caused. The recommended cost function provided in equation 1 is reflective of the costs caused by a customer interconnection at a POD.[15]

The DUC accepts the AESO's interconnection cost function, except as it applies to large PODs, where the lack of data resulted in the AESO not recognizing the economies of scale present. The DUC does not rely on the AESO's historical TCCS data. The DUC's own experience with the design and construction of numerous substations confirms the significant economies of scale present in larger substations above the 25 MW level.

The CCA/PICA state that POD rate design should be based on the current cost structure:

> For rate design purposes, the AESO has developed a POD cost function it believes reflects the go forward cost structure of PODs. The principle of recovering embedded costs on the basis of the current cost structure is

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[12] Ex. 229, p. 14, l. 1-3 & Ex. 305, AESO-AESO-3 a) state that the current policy is one transformer; Ex. 305 and T. 1346/17 – 1347/3 show that 80% of PODs over 40 MW is size have more than one transformer.

[13] Please see page 18 to 19 where the DUC explains that the historical system investment evidence from the TCCS, including PODs with more than one transformer, aligns with the DUC's proposed interconnection cost function.

[14] Ex. 005, p. 4, l. 44

[15] Ex. 005, p. 14, l. 44

consistent with the principle of providing efficient price signals to customers while recovering embedded costs.[16]

Presumably CCA/PICA's views the historical cost structure as appropriate for cost causation led them to propose that the interconnection cost function be modified to reflect the number of radial lines that are classified as POD costs.[17] This position suggests that one should ignore the investments made from 2000 to 2006 in radial lines for PODs that were added to the system and the costs that are actually incurred. Over time some depreciated radial line costs get reclassified as local system as the transmission system expands. The quantum of costs that are actually reclassified is unknown.

Notwithstanding the position of CCA/PICA on cost causation, CCA/PICA's proposed rate design does not follow cost causation, but rather inappropriately attempts to shift costs from small to large PODs. The proposed CCA/PICA rate design is discussed under section <u>3.4.5 Point of Delivery (POD) Charge (PPGA vs. AESO vs. DUC vs. PICA approaches)</u> below.

3.4.1.2 Other Rate Design criteria (rate stability, efficiency, administrative ease, etc.)

The DUC has addressed the principles of non-discrimination or fairness, efficiency, stability, comparability and administrative simplicity below:

Non-Discrimination

The non-discrimination criterion requires that prices should promote fairness and avoid undue discrimination and undue cross-subsidization between the same class of customers and across rate classes.

The DUC submits that fairness dictates that the economies of scale present in serving DTS customers needs to be properly reflected in the DTS and PSC rates. As noted in Bonbright, both horizontal equality (the equal treatment of equal cases) and vertical equality (the unequal treatment of unequal cases) is important to ensure just and reasonable rates.

Section 30(2) of the EUA states that "the rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator."

The DUC submits that providing a lower rate for services above 40 MW, for example, is not discriminatory. The provision of rate blocks to reflect the economies of scale present is consistent with the EUA and cost causation and is good rate design.

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[16] Ex. 297, DUC-CCA/PICA-1 d)

[17] Ex. 225, p. 7, l. 28-30

The so-called "postage stamp" provision of the EUA is under section 30(3) where the legislation states that "the rates set out in the tariff shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system." We interpret this to mean that it would be discriminatory if the AESO's tariff differentiated between customers on the basis of customer location. This does not mean that economies of scale present cannot be incorporated into the tariff to properly reflect cost causation.

Efficiency

The efficiency criterion suggests that prices should be designed to promote efficient use of the transmission system. The DUC suggests that this is an important criterion particularly given the anticipated addition of large PODs in conjunction with oilsands expansions.[18]

Industrial customers have the right[19] and the desire[20] to own their own substations. The DUC submits that customer owned substations are an efficient use of the transmission system. Customer owned substations reduce TFO rate base amounts, thereby lowering AESO tariff charges to all AESO customers. In addition, especially during periods of expansion, customer built substations reduce the involvement of the AESO and the TFOs in the development and construction of customer facilities, thereby allowing the AESO and TFOs to expend their efforts in other areas of public interest.[21]

To the extent customers elect to own their own substations, the rate design should properly reflect the avoided costs to ensure that the efficiency benefits will continue to be gained. The DUC submits that its proposed rate design modifications provide the appropriate prices to ensure that additional customer owned substations will be developed.

Stability

The rate stability criterion suggests that prices be designed to be reasonably stable and predictable. This criterion can be violated when fundamental changes occur to the underlying cost structure.[22] The AESO's TCCS determined that POD costs had a much higher fixed cost component. This resulted in large price increases for smaller DTS customers under the 2006 DTS rate, notwithstanding the changes made to the DTS rate to provide price relief to smaller customers under 5 MW.

[18] Ex. 229, p. 30, l. 10-16

[19] Ex. 306, CG-DUC-7 c)

[20] Ex. 229, p. 30, l. 10

[21] Ex. 229, p. 4 l. 23 – p. 5. l. 2

[22] Decision 2005-096, p. 17

The DUC rate design proposals will not result in large price increases or decreases. Customers under 5 MW will see a 7.2% increase on average in their DTS rate charges, while customers over 50 MW will see a 2.7% reduction as a result of the DUC's proposed changes to POD charges.[23]

More importantly, when commodity prices are included, the proposed changes resulting from the DUC's recommended rate adjustments from 2005 to 2007 are negligible. Exhibit H-045 shows that the vast majority of AESO customers will receive a price increase in the 0% to 25% range regardless of the DUC's rate adjustment proposals.

For dual-use customers who currently qualify for the PSC, the proposed POD charges plus the proposed PSC rate deductions will result in a 29% increase in costs from $1.9 million to $2.6 million per year.[24] Even though the DUC members will see a significant price increase, the DUC submits that alignment of the POD charges and the PSC is appropriate.

The DUC also submits that the proper alignment of the POD charges, the PSC and the maximum investment levels should lead to greater long term rate stability and predictability. The DUC's rate adjustments provide a solid basis for future tariffs to follow a defendable process in determining rate components and maximum investment levels.

Comparability

The comparability criterion suggests that prices should be designed to reflect a consideration of comparable services offered in other jurisdictions. The PPGA attempted to use SaskPower's Power Rate to suggest that the customer charge was equivalent to a POD charge and that "dis-economies of scale" were present.[25] The DUC explained that the SaskPower rate does not contain "dis-economies of scale", but rather that the SaskPower rate customer charge includes the recovery of SaskPower metering costs:

> The basic monthly charge includes a number of components. There is a relatively small component that SaskPower collects for things like administration, billing, metering, customer service, the same types of charges that we would see in Alberta that are collected under a monthly charge.
>
> The largest component of that basic monthly charge is the monthly revenue that SaskPower determines is required to pay for the metering equipment that they provide in these customer-owned substations.

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[23] Ex. 229, Table 5, p. 24

[24] Ex. 229, Table 6, p. 41

[25] T. 1447/24-1449/8

> Under this power standard rate, as it says under the "Applicability," large commercial industrial load serves through customer-owned transformation. In fact, my understanding is, the vast majority of these customers provide their own substation. They provide the transformer, the fence, the equipment, et cetera. But what they do not provide is the metering equipment. SaskPower insists that they [SaskPower] provide the current transformer, the potential transformer, the metering equipment, and associated ancillaries that go along with that. And that is the biggest component that is included in that basic monthly charge that increases.
>
> Metering equipment, when you go from a 25-kV meter -- primary meter may cost in the range of 30 to $35,000. And as you go up to 138 or 240 -- or 230 kV, it costs significantly more. And Mr. Chesterman speaks to some of those costs.
>
> The difference in Alberta is that when a customer provides their own substation, they also provide the metering equipment, including the CTs, the PTs, and the metering equipment. They have to provide those to the AESO specifications, but nonetheless, they pay for those costs outright.
>
> So I do not believe that this increase in basic monthly charge suggests in any way that there's no economies of scale for larger services.[26]

To be comparable, the recovery of the primary metering costs would need to be removed from the SaskPower customer charge, which we submit would result in a much lower customer charge that would not increase with voltage. Since the customers on the Power Rate own their own substations, the economies of scale present in larger substations are not reflected in the SaskPower Power Rate, nor do they need to be as SaskPower has only invested in the metering equipment.

The DUC submits that the PPGA's suggestion that SaskPower's Power Rate shows that economies of scale are not present in other jurisdictions is without merit and should be rejected by the Board.

Administrative Simplicity

The administratively simple criterion suggests that prices should be designed to be practical and reasonably simple to administer and understand. The DUC submits that its proposed rate design adjustments do not add any material complexity to the DTS and PSC rates proposed by the AESO. The addition of a third "tier" will make the proposed rates slightly more complex; however, the DUC submits that this additional complexity is warranted to ensure the more important cost causation rate design criterion is upheld.

[26] T. 1319/25-1321/25

The DUC concludes that its proposed rate design adjustments appropriately meet the relevant rate design criteria.

3.4.2 Proposed Bundling of Local and Bulk System Costs

The DUC is of the view that bulk, local and POD costs are simply categories of costs that can be considered to occur along a continuum of costs from the load customer or POD to the 500 kV bulk lines.[27] The distinction between the bulk and local costs is somewhat subjective as transmission lines of one and the same size and voltage can perform a bulk transfer function in one area of the province and a local transfer function in another area of the province.[28] Moreover, over time, bulk lines can become more local in their function, just as radial lines, which are considered part of the POD costs, can become local costs once facilities are looped.

Notwithstanding that these distinctions are not hard and fast and can shift over time, the DUC submits that the bulk, local and POD cost categories are reasonably distinct and the recovery of these costs should follow cost causation. The DUC agrees with Mr. Reimer where he notes that "the further that you move from the POD to the Local System and into the Bulk System, the more diversity there is between loads and the diversity increases the difference between coincident load to maximum stress and maximum demand."[29] The DUC submits that bulk and local costs should <u>not</u> be bundled as proposed by the AESO, but rather should remain separated as per the current tariff.

3.4.4 Allocation of Costs

3.4.4.1 Bulk Wires Allocation (12 CP vs. Other)

For bulk system costs, the DUC supports the position of TransCanada, IPPCA, ADC and EnCana that the current 12 CP cost allocation and rate design, as per the current tariff, is appropriate for load customers and dual-use non-standby load customer requirements. As with IPCAA, we recommend that the Board retain the current rate design for the bulk system, which charges customers based on their coincident contributions to system peaks and has no ratchet.

3.4.4.2 Local Wires Allocation (NCP vs. Other)

For local system costs, the DUC supports the position of ADC that measured demand is the appropriate billing determinant.[30] The level of diversity that exists increases from the PODs to the 500 kV lines. The DUC submits that it follows that to reflect the increased diversity which exists as you move from PODs to the 500 kV lines, bulk system costs should be recovered based on a coincident with system peak demand billing

[27] T. 1343/8 - 24

[28] The DUC notes that 138/144 KV lines are classified as local, even though some of these lines may be performing a bulk transmission function. Ex. 012, p. 42 of the TCCU states : "The local system does not include radial transmission lines."

[29] Ex. 012, AESO 2007 GTA Appendix C - 2006 Transmission Cost Causation Update, September 15, 2006, Page 33

[30] Ex. 221, p. 42, l. 6-10

determinant and local costs should be recovered on a non-coincident monthly billing determinant without demand ratchet or Contract Capacity provisions.

3.4.4.3 POD Costs (NCP vs. Customer)

POD costs, for non-standby use, should be recovered on a non-coincident monthly billing determinant with a demand ratchet and Contract Capacity provisions to reflect the lower diversity present at the POD level, as per the current tariff.

3.4.5 Point of Delivery (POD) Charge (PPGA vs. AESO vs. DUC vs. PICA approaches)

During the 2006 tariff review process the POD charge was reviewed in detail. The TCCS indicated that POD costs contain a large fixed component and a large fixed monthly charge of $21,899 applicable to POD charges was approved. The Board provided directions to the AESO in Decision 2005-096 for the AESO to prepare an interconnection cost function that represents the average cost to interconnect the new load-only customers of varying sizes, while removing any costs related to non-standard facilities. The Board stated:

> 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."[31]

Following the issuance of Decision 2005-096, some smaller sized customers expressed concern with the large price increases that resulted from the large fixed POD charge. The Board reviewed the issue and relief was provided to customers under 5 MW in size. The Board directed the AESO in Decision 2005-132 as follows:

> The Board expects the AESO to conduct further analysis upon POD costs and to file such with its 2007 GTA. At a minimum the Board expects such analysis to contain:
>
> 1. information respecting the items comprising POD costs,

[31] Decision 2005-096, p. 58

2. the costs of PODs serving smaller loads vs. those serving larger loads,
3. a discussion of whether a reasonable break point exists between such PODs, and
4. what additional relief, if any, should be offered to customers who may have paid for the cost of their own transformation equipment.[32]

The DUC is of the view that the AESO has in large part properly responded to the Board's directions, however, the DUC submits that the proposed interconnection cost function, POD charges, PSC and maximum investment amounts should be enhanced to better reflect cost causation for larger PODs. The following sections discuss the proposals made by the AESO, the DUC, the PPGA and the CCA/PICA.

AESO Approach

The AESO responded to the Decision 2005-096 and 2005-132 directives by preparing an interconnection cost function using data from 30 substations for load only customers that were constructed between 2000 and 2006. This "greenfield" data and analysis was used by the AESO to derive its proposed raw interconnection cost function. The AESO then modified the raw interconnection cost function using TCCS data from 13 projects under 7.5 MW in size to propose an interconnection cost function with a breakpoint at 7.5 MW.[33] The resulting AESO interconnection cost function was

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

The AESO then checked the reasonableness of the proposed interconnection cost function and determined that the interconnection cost function was a reasonable representation of the cost of a new interconnection. While the AESO tested the reasonableness of the proposed interconnection cost function to the TCCS data, the AESO was of the view that the data was not of the same quality:

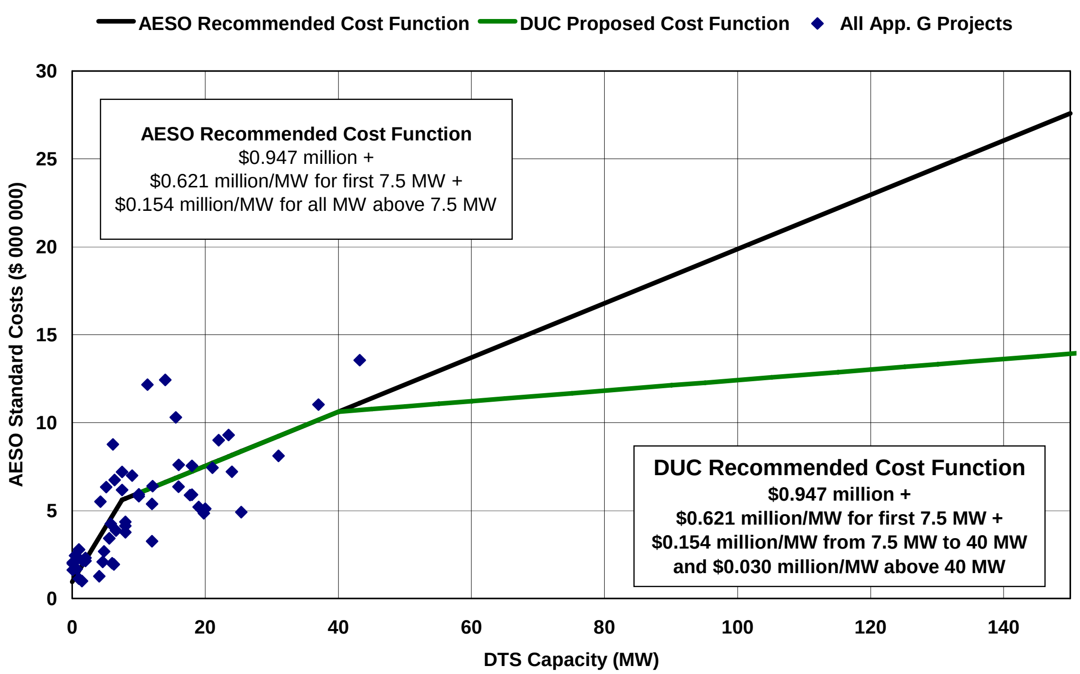
> Although the AESO analyzed the TFO data used in the *Transmission Cost Causation Study* and least-cost estimates provided in the AESO's 2005-2006 GTA to assess the reasonableness of the recommended cost function, these additional sources were not subject to the same detailed investigation and rigorous 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.

[32] Decision 2005-132, p. 4, emphasis added

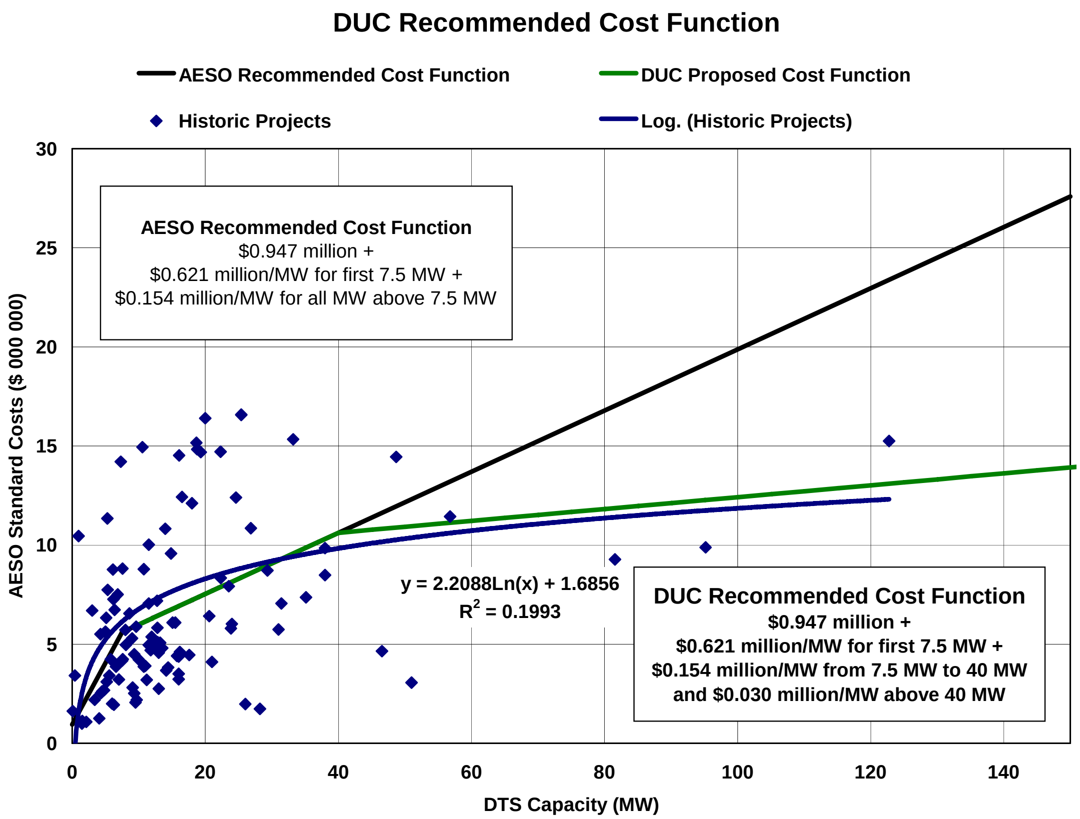
[33] Ex. 007, section 6.5.3 of Application, p. 15-24

The AESO's and the DUC's proposed interconnection cost functions are shown in the following two figures with the 55 data points from the Appendix G spreadsheet and the 109 data points from the TCCS:[34]

DUC Recommended Cost Function



[34] Ex. H-019, DUC aid to cross examination, p. 2 and 4



Having determined an interconnection cost function, the AESO then used the slopes of the interconnection cost function lines (which represent $/MW of cost to interconnect) to allocate the POD revenue requirement and determine the rate charges for NCP demand charges below and above 7.5 MW.[35] The DUC submits that the AESO's methodology is appropriate for the development of the POD charges.

However, the one area where the AESO proposed interconnection cost function needs improvement is the recognition of the lower unit interconnection costs for larger PODs. The AESO did not address the economies of scale present for large PODs due to the lack of Appendix G data.[36] The AESO needs firstly to recognize the economies of scale present for large PODs and secondly to take into consideration the AESO's present policy of not allowing TFO's to invest in more than one line, one breaker and one transformer.[37]

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[35] Ex. 006, Schedule 5.5, lines 4-7

[36] Ex. 102, DUC.AESO-013

[37] Ex. 305, AESO.DUC-3

DUC Approach

The DUC submits that the significant economies of scale present for interconnection costs should be recognized in the POD charges. The DUC is of the view that new interconnections have a significant fixed cost component (e.g. primarily transmission lines and substation land, breakers, fence, control equipment, etc.) and a smaller variable cost component (e.g. transformers).[38] While several interconnection cost components have both fixed and variable components, once a POD of size 40 MW is developed, the only significant variable cost component is the transformer, and it is these transformer costs which exhibit significant economies of scale.

There are several sources of evidence to support the position that transformers exhibit significant economies of scale:

- TransCanada evidence that suggests that transformer costs decrease from $28,000/MVA at 25 MVA to $11,000/MVA at 200 MVA.[39]
- Transformer manufacture data that suggests that transformer costs decrease from $38,000/MVA at 10 MVA to $16,000/MVA at 112 MVA.[40]
- The evidence of the DUC that transformer costs offer significant economies of scale and that incremental substation costs above 40 MW are primarily transformer related, supported by the experience of DUC's expert Mr. Chesterman.[41]

The DUC notes that interested parties did not provided the Board with any empirical evidence to refute the DUC's position that above 40 MW interconnection costs are no more than $30,000/MW.

We also note that the AESO's cross aid, Exhibit H-032, shows that transformer costs decrease from $26,000/MVA at 23 MW to $10,000/MW at 78 MW, as shown in the following table:

Transformer Voltage	Purchase Price	Size (MVA)	Load (MW)	Size (MW)	$/MW
138/25 kV	$600,000	15/20/25	0-23	23	$26,087
138/25 kV	$700,000	30/40/50	20-47	47	$14,894
240/25 kV	$750,000	30/40/50	0-47	47	$15,957
240/25 kV	$800,000	50/67/83	40-78	78	$10,256

In addition, the AESO highlighted five data points from the TCCS of size over 40 MW in their rebuttal evidence. The additional five data points provide additional verification for

[38] Ex. 306, CG-DUC-1 & CG-DUC-9 b), T. 1286/10-24 & Ex. 308, PPGA-DUC-5 a)

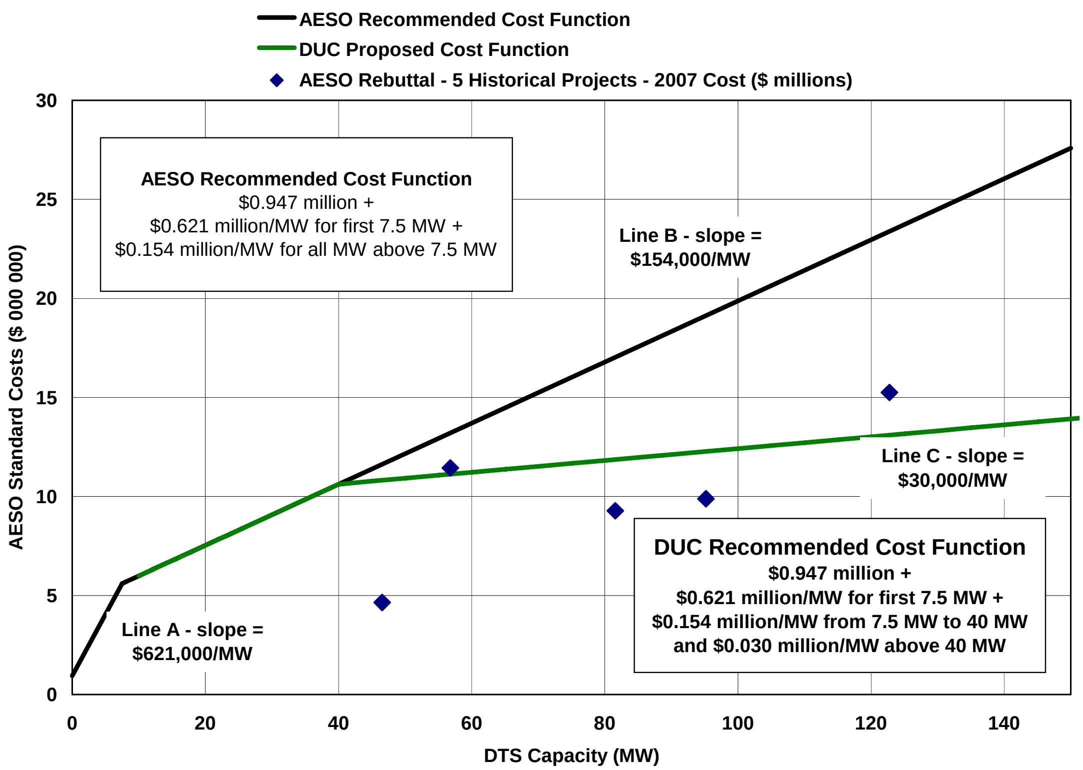
[39] Ex. 229, p. 15

[40] Ex. 229, p. 16

[41] Ex. 306, CG-DUC-1 & CG-DUC-9 b)

the DUC interconnection cost function as the data points are scattered around the DUC's interconnection cost function as shown in the figure below.[42]

DUC Recommended Cost Function



The AESO questioned the DUC recommendation that the Line C (third tier) slope could be higher than $30,000/MW if more than one transformer was provided as standard facilities.[43] The DUC's evidence is that the AESO no longer provides more than one transformer as part of its standard service. In addition, we note that the five data points referenced in the AESO's rebuttal evidence[44] and shown in the figure above, demonstrate that even for substations with more than one transformer average costs are about $30,000/MW. The table below shows that of the five data points the AESO referenced, four have more than one transformer, two are served by more than one transmission line, and one is served at 245 kV:[45]

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[42] Ex. H-019, DUC aid to cross examination, p.3 & T. 1290/4-8

[43] Ex. 305, AESO-DUC-3

[44] Ex. AESO rebuttal evidence

[45] First five columns from Ex. 347 AESO Rebuttal Evidence, p. 1-2, next six columns from Ex. 256, DUC.AESO-3, corresponding data for the same substations

		DTS Capacity	Original Cost	2007 Cost	Transformer Data			Line Data	
Substation	Year	(MW)	($ 000 000)	($ 000 000)	Number	Size	Voltage	Number	Voltage
122S	1990	122.8	$10.12	$15.25	3	75	245	1	240
308S	1990	56.8	$7.59	$11.44	2	50	138	2	138
332S	1999	95.2	$7.99	$9.89	2	50	130	2	138
365S	1991	46.6	$3.26	$4.65	1	83.3	138	1	138
484S	1988	81.6	$5.59	$9.28	2	62.5	130	1	138

Since the interconnection cost for these PODs are scattered around the DUC interconnection cost function, the DUC submits that this evidence further supports its conclusion that even assuming a POD is served by more than one transformer or line, the DUC interconnection cost function is appropriate for PODs over 40 MW in size. Thus, the DUC is of the view that the interconnection cost function above 40 MW should be $30,000/MW or less, in particular, should the AESO continue with its policy of only allowing one transformer to be classified as standard facilities.

PPGA Approach

The PPGA's approach fails to recognize the efforts the Board took at the end of the last proceeding in Decision 2005-123 to provide rate relief for small sized PODs under 5 MW. The PPGA also fails to appreciate the efforts of the AESO to modify the proposed interconnection cost function to lower the fixed cost component of the POD charges (from $21,899 under the current tariff to the proposed to $4,762) by introducing a break point in the interconnection cost function at 7.5 MW. These initiatives were undertaken to reduce the impact of the price increase for smaller sized PODS, while ignoring interconnection cost economies of scale and thus violating the cost causation rate design criterion in favour of the secondary rate criterion of price stability.

In this proceeding, the PPGA firstly tries to deny that any economies of scale are present in interconnection charges by proposing a linear interconnection cost function.[46] The rationale for this proposal appears to be that the extensive analysis and stakeholder consultation the AESO performed was not good enough.[47]

Secondly, the PPGA alternatively proposes an interconnection cost function with a breakpoint at 17 MW.[48] This alternate proposal also suggests that the interconnection cost function should not be used to allocate POD revenue requirements costs. Rather the PPGA uses different slopes to represent the best fit lines for the data points above and below 17 MW.[49] This approach causes a discontinuity at 17 MW. A discontinuity in the cost function moves the PPGA alternate proposal further away from cost causation. This alternate proposal also ignores economies of scale above 17 MW.

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[46] Ex. 239, p. 15. We note that the PPGA admits that economies of scale exist, T. 1475/1-3

[47] T. 1446/20-1447/6 & T.1578/19-1580/2

[48] Ex. 239, p. 17

[49] Ex H-034

The DUC submits that the PPGA submissions do not reflect cost causation, add little value to the development of a fair and reasonable tariff, and should be rejected by the Board.

CCA/PICA Approach

Similar to the DUC, CCA/PICA appears to generally support the AESO's proposed methodology for the development of an interconnection cost function and POD charges. The CCA/PICA proposes a modification to the AESO's interconnection cost function to average the radial lines costs over all substations:

> In CCA/PICA's view, the radial line costs included in the interconnection cost function for PODs should reflect an average cost for radial lines as a result of the radial line costs being averaged over all substations.[50]

> …since the cost of looped lines are already included in the local system costs, the POD cost function should only reflect recovery of radial line costs for those PODs with radial lines, not looped lines, to avoid a double-counting of these costs.[51]

There are two fundamental problems with this approach. The first is that radial line costs do not vary with POD size. As shown on Figures 3 and 4 of the DUC's evidence,[52] radial line costs vary with distance not POD size. It therefore follows that radial line costs should be classified as fixed costs as there is no cost correlation to POD size. If anything, separating out radial line costs should lead one to conclude that the current $21,899/month and the AESO proposed $4,720/month POD fixed monthly charge should be higher. There is no basis to assume that radial line costs should be allocated to all substations <u>on the basis of size</u>**,** which is what the CCA/PICA are proposing.

Secondly, and more importantly, the CCA/PICA state that "the POD cost function should only reflect recovery of radial line costs for those PODs with radial lines." However, there is no evidence to indicate which PODs have radial lines and which do not. Again, from Exhibit 229 Figure 4, the evidence suggests that radial line costs do not vary with POD size. The CCA/PICA proposal attempts to inappropriately shift costs to large PODs on the premise that larger PODs have a greater proportion of radial line costs, when in fact there is no evidence to suggest this is true.

As with the PPGA, the CCA/PICA failed to provide a witness with industry experience to support their premise that larger PODs have higher radial line related costs.

The net result of the CCA/PICA proposal is to increase the POD charges to larger sized PODs, while reducing the charges to smaller PODs. As noted in the table on page 4,

[50] Ex. 225, p. 8
[51] T. 1970/12-18
[52] Ex. 229, p. 10-11

the CCA/PICA is proposing a higher POD charge for Billing Capacity over 7.5 MW of $912/MW/month.

The CCA/PICA proposal is counter to all the evidence on the record indicating significant economies of scale for larger PODs. The DUC submits that the CCA/PICA proposals with respect to POD charges are without merit and should be rejected by the Board.

3.4.6 Rate Shock (including Mitigation Measures)

The DUC notes that rate shock is typically applied by the Board on a rate class basis, with an overall 10% rate class increase considered to be unacceptable.[53] This test is not applicable for the AESO's tariff as currently there is in essence only one rate class (DTS) for all transmission connected firm load requirements.

The Board noted in Decision 2005-096 that cost causation is the primary rate design criteria. However, the Board also indicated that consideration should be given to "a dramatic change in cost structure."[54] The legislative changes required under the *Transmission Regulation* and the application of the TCCS resulted in large price increases and decreases under the current 2006 tariff. These price changes were mandatory and are now past. The Board considered the price increases for small customers in Decision 2005-132 and provided appropriate relief.

For this proceeding, the appropriate test of rate shock should be the comparison of the 2006 to the 2007 tariff prices. The customers most impacted by these tariff changes are the low load factor dual-use customers.[55] The DUC and TransCanada have proposed a standby rate to address this issue. Dual-use customers who are eligible for the PSC will see a 48% reduction in the amount of credits provided.[56] The DUC addresses this significant rate change by proposing to properly align the POD charges with the PSC.

With respect to rate shock stemming from the POD charges, the DUC submits that no rate shock will be created by the proposed changes between the AESO's 2006 and 2007 tariffs. The AESO has proposed to moderate POD charges by reducing the fixed charge and implementing rate blocks within the POD charges with a break at 7.5 MW. The DUC submits that, based on the evidence, these components of the AESO's proposal are reasonable and should be approved by the Board.

3.11 Primary Service Credit

In Decision 2005-096 the Board approved as final the Customer Owned Substation (COS) credits paid from 2001 to 2005 and the PSC under the 2006 tariff. The PSC appropriately compensates customers who own their own substations, the costs of which are not included in the AESO revenue requirement. In essence, dual-use

[53] For example: Decisions 2004-066, p. 138; 2004-067, p. 164; 2005-25, p. 33 & 37 & 2005-074, p. 7-8

[54] Decision 2005-096, p. 17

[55] Ex. 339, Figure 8, p. 25, large PODs with low load factors are proposed to see prices increases over 20%.

[56] Ex. 229, p. 40, l. 2-5, PSC are proposed to decrease from $6.2 million to $3.2 million.

customers pay the full DTS rate that includes the costs of substations, and the PSC provides a credit to recognize the cost savings dual-use customers provide the system. The DUC submits that the PSC is an appropriate feature of the AESO's tariff and should be maintained. The Board stated the following in Decision 2005-096 on page 39:

> Any DTS customer that has supplied its own facilities and is paying for system provided facilities through the DTS postage stamp rate, is in the position of paying twice for one set of facilities and should be credited.

As part of the AESO's 2006 tariff, the eligibility criteria for the PSC was changed to allow any customer that provided its own transformation to be PSC eligible.[57] With the AESO's proposed method of determining POD charges from the interconnection cost function, this eligibility requirement is no longer appropriate. There are no customers that only own transformation – all PSC eligible customers own their entire substation.[58]

The DUC evidence proposed PSC levels for customers that own only transformation and for customers who own their substation.[59] The AESO testified that administering two PSC levels might be a concern.[60] The DUC submits that since there are no customers who only own transformation, and it is unlikely that any customers will elect to only own transformation in the future,[61] the DUC PSC transformer only credit is not required. Thus the difficulties which might arise if two PSC levels are approved are removed. The DUC therefore submits that its initial proposal of a PSC for customers that only own their transformers priced at 15% of the POD charge need not be considered by the Board.

3.11.1 PSC Credit methodology (AESO vs. DUC approach)

The DUC is of the view that cost causation dictates that the interconnection cost function, the POD charges, and the PSC should all be aligned.

AESO Approach

The AESO used the 2006 tariff approved PSC of $660/MW/month to estimate the portion of the POD revenue requirement that is related to transformation costs.[62] The result was a determination that 40% of the POD costs were transformation related. The AESO therefore proposed that the PSC be set at 40% of the proposed POD Charges.

In the DUC's view, the AESO's determination is not appropriate for two reasons. Firstly, as noted, there are no PSC eligible customers that only own transformation: all PSC customers own their own substation. The PSC equal to 40% of POD charges proposal

[57] Decision 2005-096, p. 39

[58] T. 829/2-9 & T. 1363/17-24

[59] Ex 229, p. 36-37

[60] T. 832/4/34

[61] T. 1363/24-1364/10

[62] Ex. 005, Section 4 of Application, p. 51, l. 8-21

therefore underestimates the costs dual-use customers have eliminated from the AESO's revenue requirement.

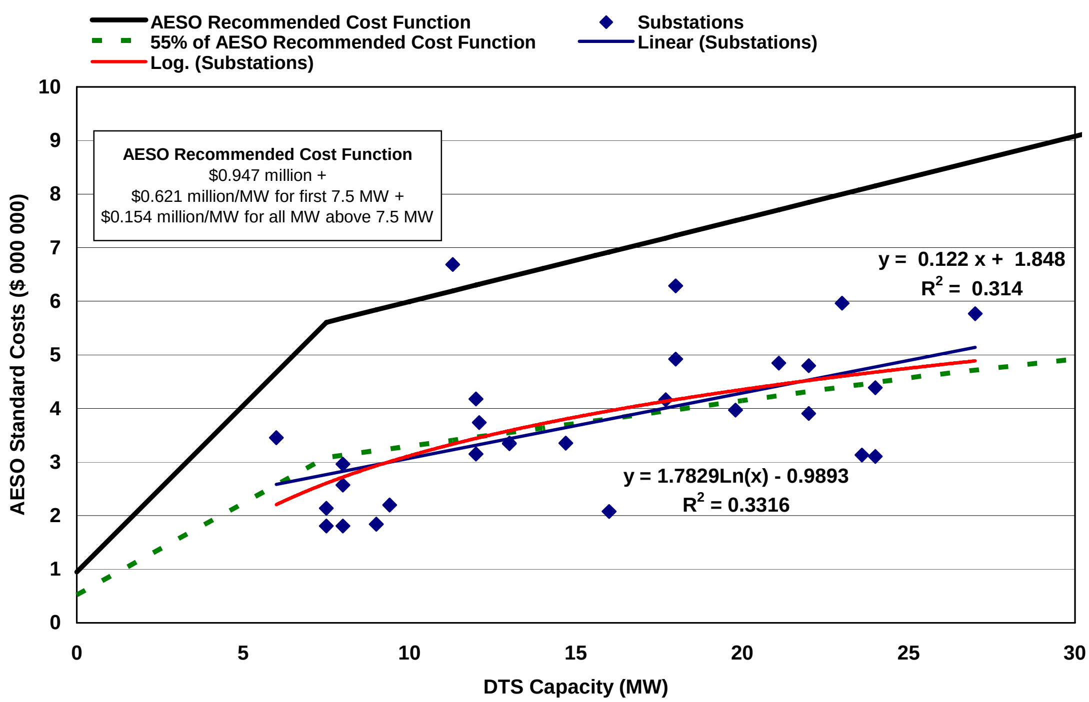
Secondly, the 2006 PSC rate of $660/MW was based on an evaluation of three transformation configurations.[63] There is no evidence to suggest that this average cost is indicative of the actual costs of transformation for actual PODs. The sample set of 28 POD specific substation costs from the AESO's Appendix G[64] analysis is a much better data source as it represents a larger sample of actual costs.

In addition, the AESO's approach does not align the determination of the POD charges with the determination of the PSC. The DUC is of the view that the two rate components should utilize the same determination methodology and data set.

DUC Approach

The DUC used the AESO evidence to show that substation related costs are about 55% of the interconnection costs.[65] It follows that the PSC, which provides a credit for customers who own their own substation, should be set at 55% of the POD charges.

AESO Recommended Cost Function & Substation Cost Data



[63] Decision 2005-096, p. 37

[64] Ex. 016, tab Subs

[65] Ex. 229, Figure 19, page 36

The DUC submits that the non-substation costs; that is, transmission line costs, are appropriately collected under the POD fixed and rate block charges up to 40 MW of Billing Capacity. Above 40 MW, the DUC has demonstrated and provided evidence that the incremental costs are primarily related to incremental transformer costs, which are fully substation related.[66] It therefore follows that the PSC for Billing Capacity over 40 MW should be set equal to the POD charge over 40 MW of Billing Capacity.

Stated another way, once a customer has paid the POD charges (and received the PSC) for billing capacity up to 40 MW, the customer has made a full and appropriate contribution to all non-substation related costs, which are primarily transmission line related costs. There is no evidence to suggest that PODs over 40 MW have higher transmission costs and that a customer should continue to provide revenue to the AESO to recover incremental <u>transmission</u> related costs. Above 40 MW, all costs are <u>substation</u> related, and since a PSC eligible customer has provided the entire substation, the POD and the PSC rates should be equal for Billing Capacity over 40 MW.

The DUC's position on the PSC was summarized in Exhibit H-039:

> As noted, the DUC believes that POD charges, the PSC, and the maximum investment levels should all be aligned. The DUC supports this alignment even though it will mean a substantial reduction in the primary service credits paid to dual-use customers from those paid under the AESO's 2006 tariff should the AESO's proposal be accepted.
>
> We note as well, however, that if the Board does not accept the AESO's proposed methodology, then the primary service credits paid to dual-use customers should continue to be set at $660 per megawatt with an inflation adjustment as suggested by the PPGA.[67]

The DUC submits that if the $660/MW/month credit is maintained, an inflation adjustment is appropriate as it was contemplated by the Board in Decision 2005-096:

> The Board directs the AESO to use this amount [$660/MW/momth] for the calculation of future PSC Credits. The Board is willing to entertain adjustments in the future to reflect changes in costs over time.[68]

The DUC considers proposed adjustments to the POD charges and PSC as a "package deal."[69] We submit that it would not be appropriate to adjust one tariff component without the other as the PSC is simply a refund of the POD charge to reflect customer investment.

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[66] Ex. 229, p. 18-19

[67] T. 1282/2-16

[68] Decision 2005-096, p.39

[69] T. 1284/13-19

3.11.2 Eligibility

While extension of the PSC to isolated generation units is not a significant dollar value item, the DUC is of the view that the principles behind the PSC suggest that ATCO Electric's isolated generation units should not be eligible for the PSC.[70] Since there was no avoided transmission investment, there is no need to provide a credit to ATCO Electric.

For the two Unconventional Interconnection sites, the provision of the PSC is appropriate as the use of devices like potential transformers instead of a transformer likely resulted in a significant capital cost reduction.[71]

4. Terms & Conditions of Service

4.1 Customer Contribution Policy

The DUC supports the AESO's methodology of determining the maximum investment levels from the interconnection cost function. If the Board accepts the DUC's proposal that the interconnection cost function should have an additional breakpoint at 40 MW to reflect the economies of scale of larger PODs, then the maximum investment amounts should be proportionately lower above 40 MW.

The DUC notes that the AESO escalated the Greenfield (and the TCCS) project costs to 2007 values, which were used to develop the interconnection cost function. The AESO used the following escalation rates, which are equivalent to Alberta CPI statistics:[72]

Present Value Index			
Year	Index	% Change	
1999	113.40	3.53%	
2000	117.40	2.30%	
2001	120.10	3.41%	
2002	124.20	4.43%	Actual index values
2003	129.70	1.39%	
2004	131.50	2.13%	
2005	134.30	2.20%	
2006*	137.25	2.22%	
2007*	140.30	2.00%	Estimated index values

The DUC also notes that Alberta is experiencing accelerated economic growth that is leading to higher prices for transmission infrastructure (labour, steel, etc.)[73] and that the AESO's 2007 tariff will likely be in effect from late 2007 until at least 2009, assuming the AESO files a 2008 tariff application. The DUC therefore recommends that the AESO's interconnection cost function and maximum investment amounts be increased by 5% to

[70] Ex. 229, p. 37-39

[71] T. 1367

[72] Ex. 016, Appendix G spreadsheet, tab Cost Data Subs 2007, cells E34:G44

[73] T. 1325/24-1327/9

reflect the higher costs that the TFO's will experience during the time the 2007 tariff is in effect.

The DUC notes that increasing the underlying project costs by 5% will in essence "shift" the proposed interconnection cost functions upward, however, the line slopes would not change, hence no changes to the proposed POD or PSC rates would be required.

4.7 Payments in Lieu of Notice (ADC evidence issue of exit fees)

The AESO's proposed Payment in Lieu of Notice charge is discussed in section 6 of the AESO's application on pages 36-37, Exhibit 007. The AESO is proposing to charge exiting customers the present value of five years of DTS system demand charges.

The DUC submits that there are two issues with respect to the Payment in Lieu of Notice that the Board should address:

1. The appropriate DTS rate component to apply to determine the Payment in Lieu of Notice charge (AESO proposed DTS System demand charges[74])
2. The period of time the DTS rate component is applied to determine the Payment in Lieu of Notice charge (AESO proposed 5 years[75]).

The DUC submits that in order to uphold the primary cost causation rate design criteria, any Payment in Lieu of Notice charge should be cost based. The AESO's proposal of basing the Payment in Lieu of Notice charge on the DTS rate system demand charge implies that an exiting customer should be responsible for bulk and local costs for an additional five years.

This approach ignores cost causation as no bulk transmission costs may have been provided for a low load factor standby customer. Conversely, based on the confidential data analysis performed by DUC and TransCanada,[76] a high load factor DTS customer is much more likely to have caused bulk and local transmission assets to be built to provide service than a low load factor standby customer. The AESO's proposed Payment in Lieu of Notice charge would impose the same amount on customers of similar size regardless of load factor or the type of customer (load only or standby use).

The five year provision implies that an exiting customer will strand bulk and local costs, on average, for a period of five years. In reality, in an area of the province where additional transmission capacity is required, an exiting customer may defer the need for transmission expansions. As noted by ADC, the five year notice provision is unlikely to benefit the AESO from a planning perspective,[77] in which case the Payment in Lieu of Notice charge is simply a penalty and violates regulatory principles as the charge is not cost based.

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[74] Ex. 102, DUC.AESO-015

[75] Ex. 007, section 6.5.3 of Application, p. 35, l. 27-30

[76] Ex. H-021 and the DUC and TransCanada argument, p. 4-12

[77] Ex. 221, ADC evidence, p. 45

The DUC submits that with the additional evidence the DUC and TransCanada have provided in this proceeding the Board should revisit the determination of the Payment in Lieu of Notice charge. If the Board considers that an exiting customer will stand bulk and system costs, then the DUC submits that the Payment in Lieu of Notice charge should reflect cost causation.

The best indicators of cost causation are the DTS rate charges that attempt to collect revenues based on how the costs are and/or were incurred. In order to differentiate between costs incurred by low and high load factor customers, the DUC submits that the DTS rate components that are designed to collect bulk and local costs be used. This means that both demand (including whatever ratchet, contract capacity, etc. provisions that are embedded) and energy charges should be applied in the determination of the Payment in Lieu of Notice charge.

However, to ensure that the Payment in Lieu of Notice charge is not excessive, and considering the ADC evidence, the period over which the Payment in Lieu of Notice charge should be applied should be reduced to two years.

The DUC submits that a simple determinant of the Payment in Lieu of Notice charge, should the Board determine that a charge is appropriate, would be the prior 24 months of all DTS rate bulk and local charges. This approach will align the Payment in Lieu of Notice charge with the customer’s actual use of the bulk and local system, taking into consideration diversity (via load factor and coincident demand if the Board retains the 12 CP rate design for bulk system costs). This approach will also be administratively simple as there should be little debate as to what the historical bulk and local charges were for the prior 24 months.