APPLICATION NO. 1485517

ALBERTA ELECTRIC SYSTEM OPERATOR (AESO)

2007 GENERAL TARIFF APPLICATION

DUAL USE CUSTOMERS

POD CHARGES AND PRIMARY SERVICE CREDIT EVIDENCE

March 16, 2007

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION AND RECOMMENDATION SUMMARY

Desiderata Energy Consulting Ltd. has been retained by the Dual Use Customers (the "DUC")[1] to review the AESO's 2007 General Tariff Application ("2007 GTA") and to present evidence to the Alberta Energy and Utilities Board (the "Board") on behalf of the DUC concerning the AESO's proposed rate design and Terms and Conditions of Service related to Point of Delivery charges and Primary Service Credits. This evidence addresses these issues.

The DUC member companies are large industrial load and generation supply customers who elected in response industry deregulation to build non-regulated generation facilities. At industrial sites where on-site generation as been developed electric energy is taken from and provided to the transmission system, hence, customers at these locations are called "dual-use" customers.

As part of their decision to build non-regulated generation, DUC members elected to pay for and to own certain transmission assets, including substation facilities. The decision by DUC members to pay for and own transmission assets was based in part on government policy and provisions in the former Transmission Administrator's tariff which provided for the payment of "Customer Owned Substation" or "COS" credits.

The COS credits were changed to the "Primary Service Credit" or "PSC" under the 2006 AESO Tariff but the nature of the credit and rationale for the payment of the credits remained the same. PSCs are paid in recognition of the investments made by dual-use customers in transmission facilities that would otherwise have been paid for by a TFO and recovered from all customers through the AESO's tariff.

Although the payment of credits has been and remains an important factor in the decision of dual-use customers to own their own transmission facilities, dual-use customers have historically elected to own transmission assets for other reasons as well. In some situations dual-use customers may desire to have operational control over onsite transmission assets. Indeed, some customers place significant value on the greater reliability they see as possible through direct ownership and control over local transmission assets. In addition, designing, building and owning transmission assets

[1] Formally the COS Coalition, who participated in the last three AESO tariff proceedings. DUC is comprised of the following members:

Air Liquide
ATCO Power
Canadian Natural Resources Limited
Imperial Oil
Petro-Canada
Shell Canada Limited
Shell Canada Products
Suncor Energy

DUC members represent approximately two thirds of the existing PSC customers on a Billing Capacity basis.

provides a greater degree of control over capital costs when compared to assets supplied by a TFO via the AESO.

The DUC members continue to support the development of on-site generation in the province. However, the DUC members are of the view that it is essential that the past investments of existing dual-use customers, and the potential future investments of existing and new dual-use customers in transmission and on-site generation assets and the corresponding reduction in costs to all AESO customers, continue to be recognized through the payment of appropriate credits.

The COS credit was first proposed by the Transmission Administrator in its 99/00 GTA proceeding. A credit of $700/MW/month was approved by the Board in Decision 2000-34, effective June 1, 2000, for all customers who elected to own their own substation. In the 2005 AESO GTA, the Board approved all former COS credit payments as final and set the PSC at $660/MW/month under the AESO's 2006 Tariff.

The AESO has proposed that the PSC be radically altered from the current Board approved $660/MW/month rate to 40% of the POD charges, which will result in lowering the annual PCS from $6.2 million to $3.2 million or by about 48% from that paid under the AESO's 2006 Tariff. This is a significant change that will have a material impact on the dual-use customers.

The DUC members question the need to change the derivation of the PSC at this time and the fairness of that change. However, if the Board accepts the AESO's proposed methodology to design Point of Delivery ("POD") charges based on a cost function that estimates interconnection costs, then enhancements to the cost function and the resulting POD and PSC rate design are required.

The AESO has filed a significant amount of evidence in this proceeding to estimate the cost to interconnect a new customer. The AESO used this evidence to derive a Recommended Cost Function (the average cost to interconnect customers of varying size). The Recommended Cost Function is also utilized to allocate the POD related revenue requirement, to determine the DTS POD charge rates and to derive the maximum investment amounts under the AESO's contribution policy.

It is our understanding that the AESO has filed this evidence in response to the Board's directives on page 58 of Decision 2005-096. If the Board accepts the AESO's methodology, then the DUC members are of the view that additional refinements to the rate design are required to appropriately align the POD charges with cost causation and subsequently to align the PSC with the cost avoidance from customer owned substations.

The additional evidence and analysis provided by the AESO, supplemented by the additional evidence provided herein, strongly suggests that the POD charges should be lower for customers taking service at PODs larger than 40 MW and that the PSC rate should be decreased for customers that own their own transformers and should be increased for customers that own their own substations.

The following recommendations are made to enhance the AESO's POD and PSC rate design to ensure that dual-use customers will continue to receive an appropriate tariff cost reduction when investments are made in transmission assets that could have been made by the TFOs and to recognize the economies of scale of larger sized interconnections:

1. The recommended cost function 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 recommend 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 cost function by adjusting the maximum investment amounts, including lower maximum investment amounts for services with DTS Contract Capacity over 40 MW.
4. The PSC should be adjusted to be 15% of the POD Charges for customers who own their own transformation assets.
5. The PSC should be adjusted to be 55% of the POD Charges for customers who own their own transformation assets.
6. Isolated generation PODs should not be eligible for the PSC.

The spreadsheets used to assist with the preparation of this evidence have been filed with the Board and are listed under APPENDIX – NOTES ON SPREADSHEETS PROVIDED.

1.0 COST FUNCTION

We analyzed the AESO's Recommended Cost Function and the underlying cost data. We note that the Board anticipated that there should be economies of scale present in interconnection costs (i.e. that interconnection costs should decrease with interconnection capacity):

> 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.[2]

In the last AESO proceeding and in the stakeholder consultations leading to this proceeding there was a significant amount of analysis and debate over the appropriate level of POD charges for DTS customers with billing capacities under 10 MW.[3] Unfortunately, insufficient attention has been paid to those customers at the other end of the size continuum.

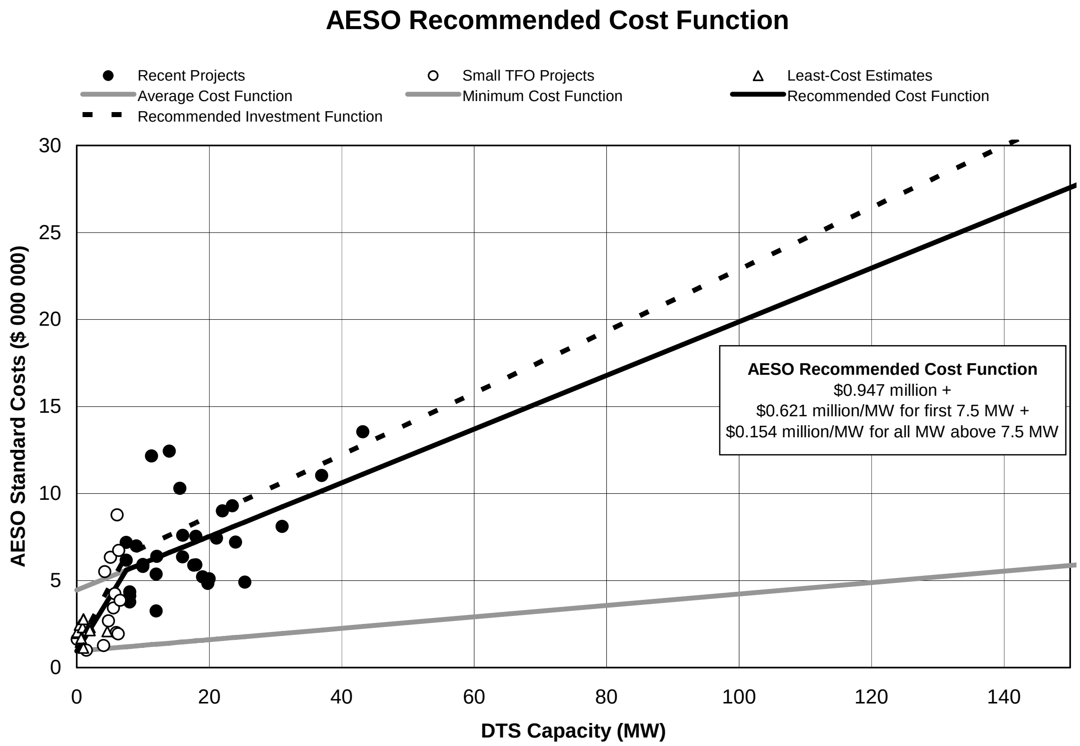
In our view, the AESO's analysis, while helpful, does not reflect the significant economies of scale present in PODs over 40 MW. The AESO prepared its recommended cost and investment functions as shown in Figure 1 that shows the estimated average cost to interconnect new customers to the transmission system.[4]

[2] Decision 2005-095, p. 58, item 2.

[3] We have not analyzed cost causation of small sized PODs and offer no recommendations on adjustments to the cost function for PODs under 10 MW in size.

[4] AESO Appendix G spreadsheet, see DUC POD PSC Evidence App G Revised.xls, tab Chart

Figure 1 – AESO Recommended Cost Function



Unfortunately, the AESO only has three data points for new interconnections with DTS Contract Capacity above 30 MW. These represent only 5% of the 55 projects in the data set.[5] One hundred and six PODs, or 22% of the 491 PODs, have an average Billing Capacity over 30 MW.[6] In our view the AESO's data for PODs over 30 MW is insufficient and we question the accuracy of the proposed AESO Recommended Cost Function for larger PODs.[7]

The following Figure 2 shows the size range of PODs based on average Billing Capacity and average load factor.[8]

---

[5] DUC POD PSC Evidence App G Revised.xls, tab All Projects, cells B1:E1

[6] DUC POD PSC Evidence BR 3 Expanded.xls, tab BR-003 (a)-A3 Per Pod, cells AQ1:AR3

[7] We do so while recognizing that interconnection capacity is not the same as, and like higher than, Billing Capacity.

[8] DUC POD PSC Evidence BR 3 Expanded.xls, tab LF vs POD Capacity

Figure 2 - Scatter Plot of Average POD Billing Capacity vs. Average Billing Load Factor

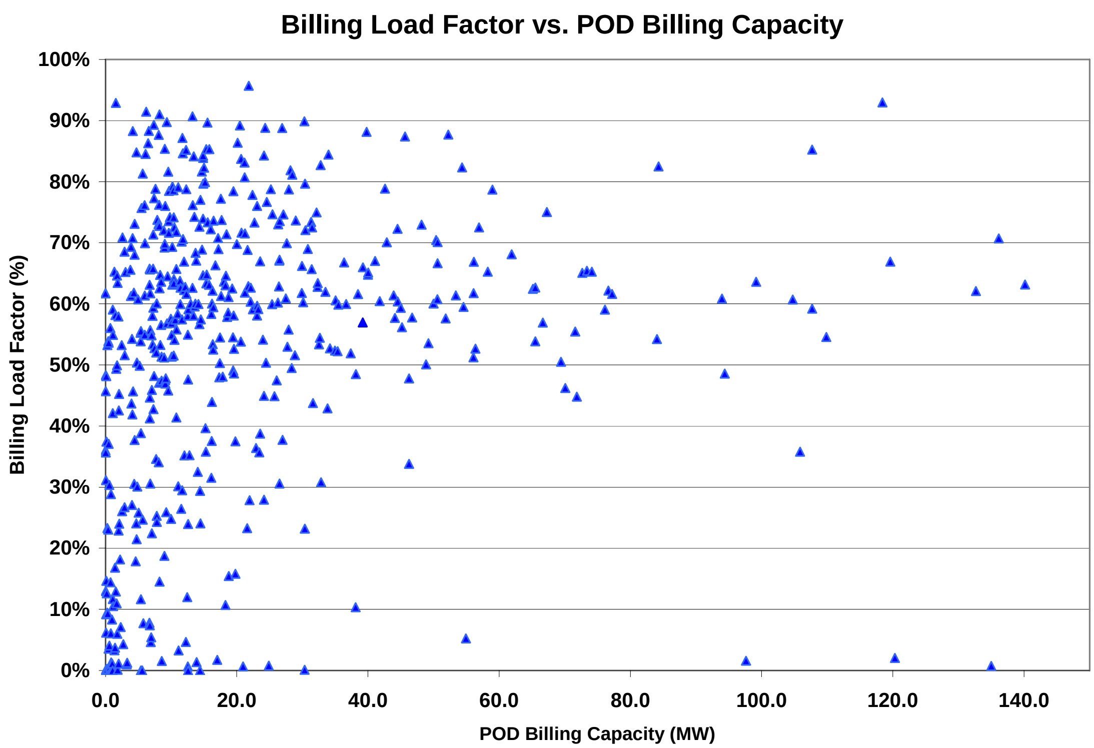


Figure 2 shows that the vast majority of PODs over 40 MW have average billing load factors above 40%. Of the 70 PODs over 40 MW average Billing Capacity, 90% have average billing load factors above 40%, and all but three PODs over 40 MW have average billing load factors above 5%.[9]

We note that the AESO's Recommended Cost Function suggests that interconnection costs will continue to increase on average at a rate of $154,000/MW for PODs above 7.5 MW. This is not consistent with our experience. Nor in our view is it supported by the data.

In general, we view interconnection costs to have two primary cost components:

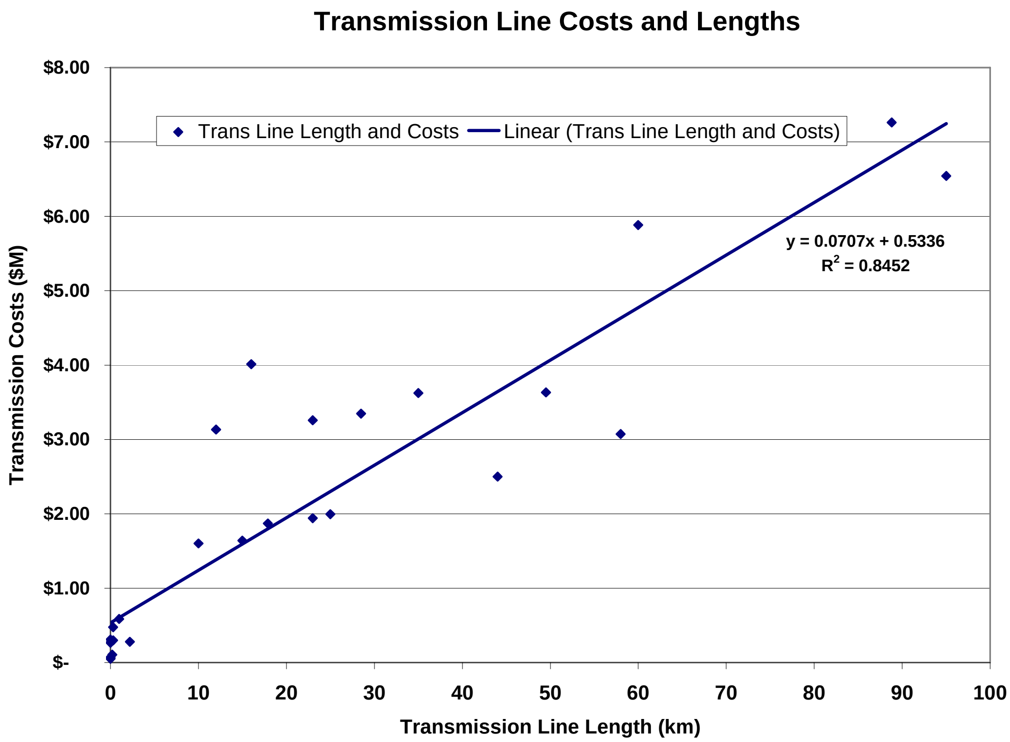
1. Transmission line costs
2. Substation related costs

[9] DUC POD PSC Evidence BR 3 Expanded.xls, tab BR-003 (a)-A3 Per Pod, cells AQ5:AR9

1.1 TRANSMISSION LINE COSTS

For similar sized facilities, variations in transmission line costs are expected to be primarily a function of distance. The AESO's data shows a high level of correlation between transmission line costs and transmission line length. This data is shown in Figure 3.[10]

Figure 3 - Correlation of Transmission Line Length vs. Transmission Lines Costs



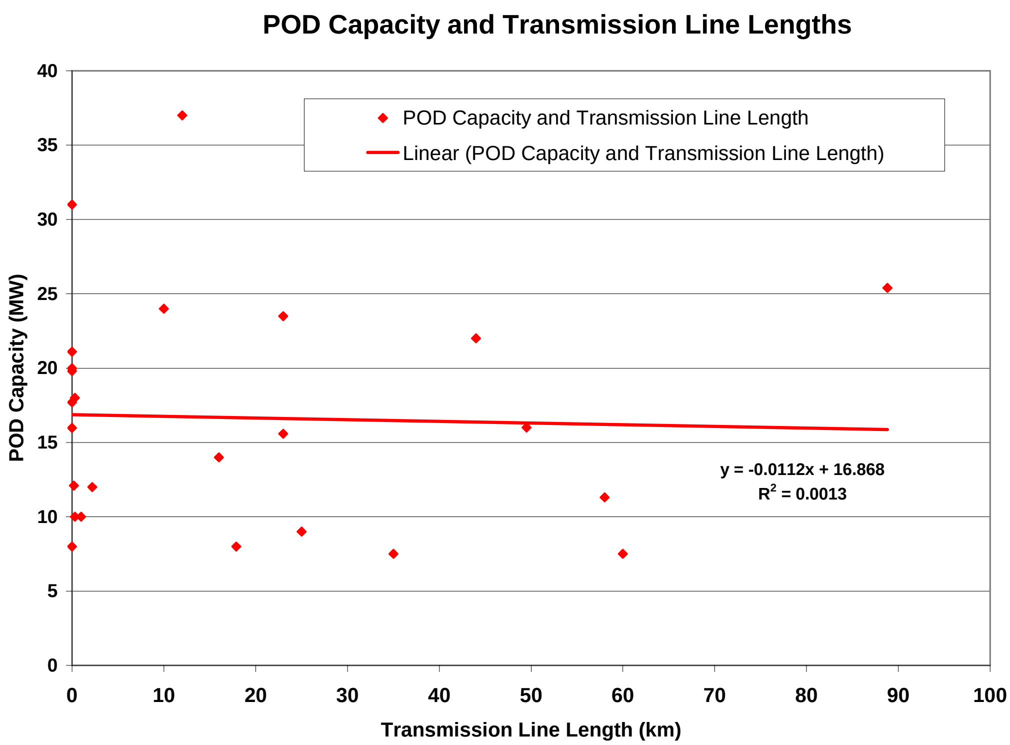
Undoubtedly there will be differences in unit transmission line costs ($/km) based on voltage level, conductor size, type of structure used, geography, etc. However, as shown in Figure 4 the AESO data shows that there is little correlation between POD capacity and transmission line lengths.[11]

---

[10] AESO Appendix G spreadsheet, tab Trans Lines Length, see DUC POD PSC Evidence App G Revised.xls, tab Trans Lines Length. High correlation is evidenced by the R^2 statistic of 85%. The AESO provided similar analysis in TCE.AESO-025.

[11] AESO Appendix G spreadsheet, correlation of data for 25 projects that are listed on both the Greenfield and the Trans Lines tabs. See DUC POD PSC Evidence App G Revised.xls, tab Trans Lines DTS. Low correlation is evidenced by the R^2 statistic under 1%.

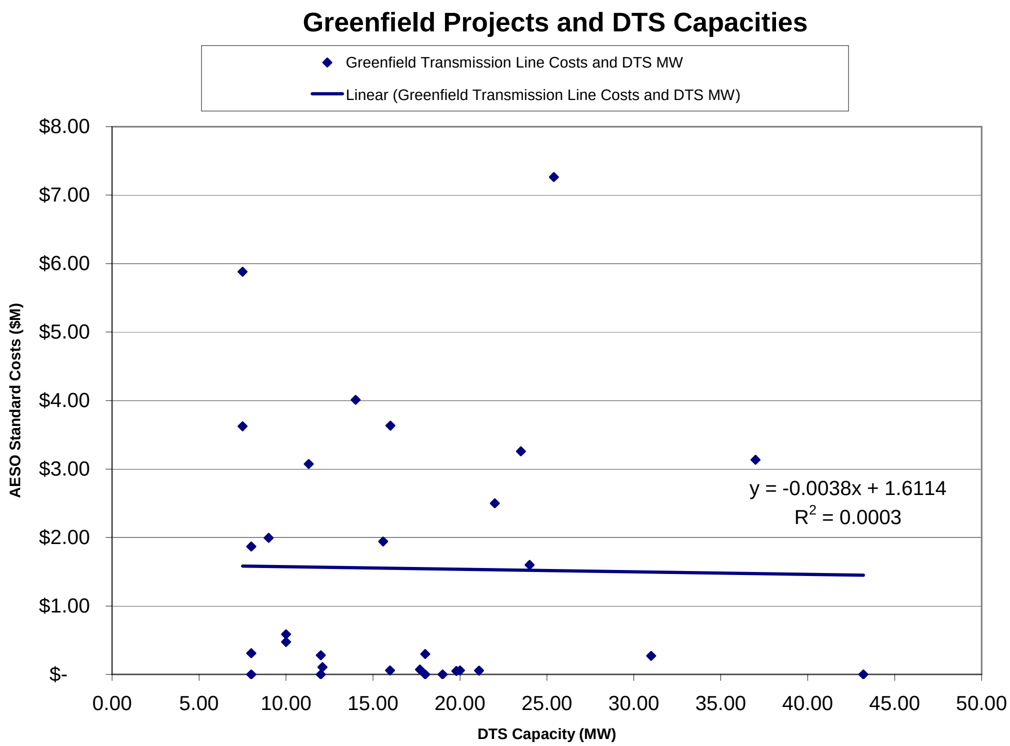
1 Figure 4 - Correlation of Transmission Line Length vs. POD Capacity



2 The AESO's cost data also shows little correlation between DTS Capacity and
3 transmission line costs, and that the average transmission line cost over this sample set
4 is about $1.5 million, as shown in Figure 5.[12]

[12] AESO Appendix G spreadsheet, tab Greenfield, with DTS Capacity (col D) plotted vs. Transmission line Costs (col F). See DUC POD PSC Evidence App G Revised.xls, tab Greenfield Line Cost. Low correlation is evidenced by the R^2 statistic under 1%. The AESO also analyzed DTS Capacity vs. Radial Line Costs as provided in TCE.AESO-025 and came to the same conclusion that there is little correlation between radial line costs and DTS Capacity.

Figure 5 - Correlation of POD Capacity (DTS Capacity) vs. AESO Standard Interconnection Costs



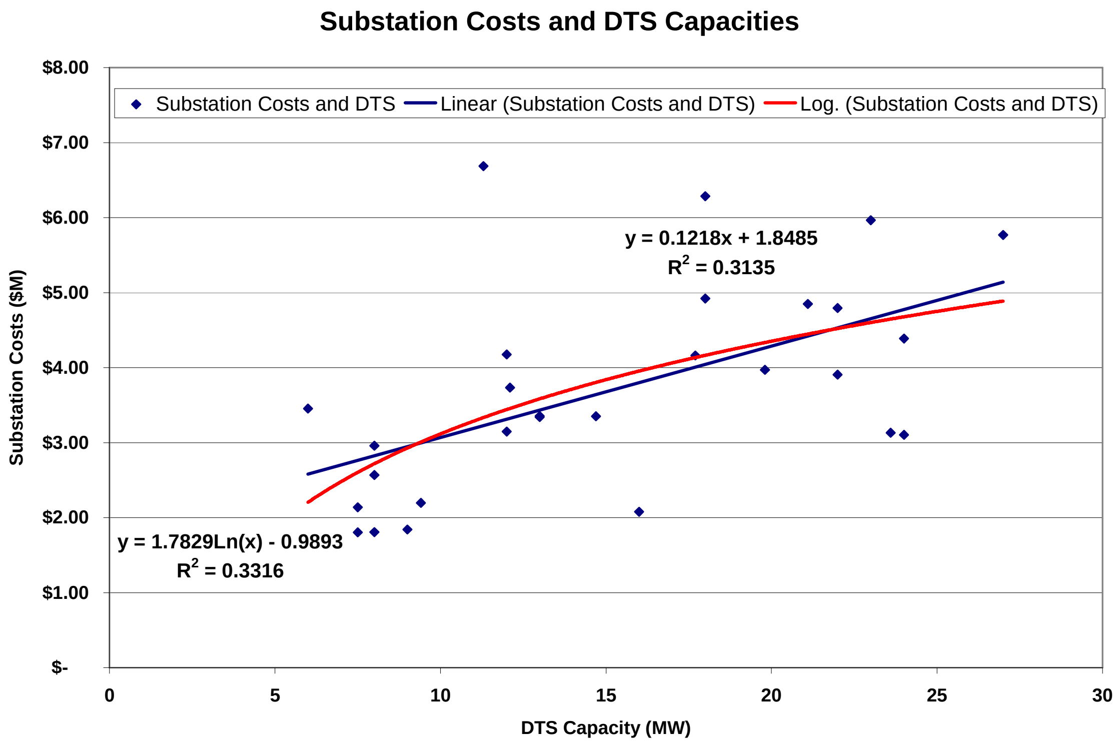
One would not expect all large capacity substations to be connected via larger capacity, longer or higher cost transmission lines. In general, for PODs 30 to 100 MW, a single 138/144 kV transmission line can provide the standard level of service as defined by the AESO. If a new POD happens to be close to a 240 kV line, service can be provided from the 240 kV line if that is the most cost effective option. Some PODs are supplied by radial lines, while others are supplied by lopped lines where the AESO treats the transmission line costs as system costs.

While we concede that higher capacity PODs may need higher capacity transmission lines to provide service, we do not believe that there is a strong correlation between transmission line costs and POD capacity (and there is no AESO evidence to suggest such a correlation).

1.2 SUBSTATION RELATED COSTS

The second interconnection cost component relates to substation costs. The data with respect to substation costs vs. substation capacity provided by the AESO shows that there is some correlation between substation costs and capacity. This is shown in Figure 6.[13]

Figure 6 - Correlation of POD Capacity (DTS Capacity) vs. AESO Substation Costs



Unfortunately, the substation cost data is limited to 28 substations and there is no cost data for substations over 30 MW in size.[14] We are of the view that there is not a linear correlation between substation costs and DTS capacity for larger substations. The best fit logarithmic equation to the data suggests a slightly better correlation than the best fit linear equation as evidenced by the higher R^2 value (33% vs. 31%).

In particular, in our view, contrary to that suggested by the best fit linear regression line in Figure 6 above, new substations over 30 MW in size do not have incremental costs of $122,000/MW. Using the AESO's recommended cost function, which we reject, would suggest that a 150 MW POD would have a total interconnection cost of $27.6 million.[15] In addition, using the best fit linear substation cost equation would suggest a substation

---

[13] AESO Appendix G spreadsheet, tab Subs. See DUC POD PSC Evidence App G Revised.xls, tab Subs Chart. Some correlation is evidenced by the R^2 statistics of 31% and 33%.

[14] DUC POD PSC Evidence App G Revised.xls, tab Subs, Cells L2:M3

[15] DUC POD PSC Evidence App G Revised.xls, tab All Projects, Cell E34

cost of over $20 million,[16] which does not appear consistent with the AESO's own cost data, especially considering that the AESO's standard substation would consist of a single transformer.[17] Using the best fit logarithmic equation would suggest a substation cost for a 150 MW POD of only $7.9 million.[18]

It is anticipated that substation costs have some level of fixed costs, as the AESO suggests, and that there are some incremental costs that are related to size, e.g. transformers, breakers, etc. However, as discussed, we are of the view that substation costs do not continue to increase at the same rate with size. Below we provide evidence that shows that incremental substation costs above 30 MW should be limited to transformation costs, which increase with size at the much lower rate of about $10,000 to $30,000/MW.

During the AESO's 2006 Tariff review process TransCanada Energy filed evidence indicating that both transmission line and substation costs exhibit economies of scale.[19] The following Table 1 shows information filed in response to an information request from the FIRM Group.[20]

---

[16] DUC POD PSC Evidence App G Revised.xls, tab Subs, Cell M5

[17] The Board addressed this issue in Decision 2006-046 and noted the AESO's POD criteria outlined in Section 4.5 of the Reliability Criteria document clearly indicates that the standard level of service the AESO would provide would be a one radial line/one transformer configuration. Decision 2006-046, p. 12.

[18] DUC POD PSC Evidence App G Revised.xls, tab Subs, Cell M7

[19] AESO 2006 Tariff Proceeding, Exhibit 23-010 - TCE Evidence (Mar 11, 05), page 18-19.

[20] AESO 2006 Tariff Proceeding, Exhibit 02-019-001 - FIRM-TCE-3 Schedule A (Mar 31, 05)

Table 1 - TransCanada Transformer Cost Data

FIRM-TCE-3 Schedule A
Estimate Prepared 2005-03-07

Transformer Description	Estimated Cost (OOM +/-30%) (2005$ x 1,000)	Max capacity (MVA)	2005$ per MVA
15/20/25 MVA 138/25 kV c/w LTC	$700	25	$28
25/33/42 MVA 138/25 kV c/w LTC	$950	42	$23
30/40/50 MVA 138/25 kV c/w LTC	$1,000	50	$20
50/66/83 MVA 138/25 kV c/w LTC	$1,400	83	$17
50/66/83 MVA 240/25 kV c/w LTC	$1,700	83	$20
75/100/125 MVA 240/25 kV c/w LTC	$1,900	125	$15
120/160/200 MVA 240/25 kV c/w LTC	$2,200	200	$11

All costs include shipping and typical taxes FOB Calgary, AB.
Estimated costs based on various order of magnitude quotes from transformer vendors.

This data shows that transformation costs range from $28,000/MVA for a 25 MVA transformer to $11,000/MVA for a 200 MVA transformer.

We also received some current transformer cost information from Pennsylvania Transformer Technology, Inc. This information is shown in Table 2.[21] The data shows that this sample set of new transformers above 25 MVA have an average cost of about $20,000/MVA (US dollars converted to Canadian dollars at 0.85 $CDN/$USD).

[21] http://www.patransformer.com/products.htm

Table 2 - Pennsylvania Transformer Technology, Inc. Transformer Cost Data

MVA	HV	LV	YV	Type	Tap Chgr	Price, USD	Size	$/MVA CDN
7.5//10	72	4.16		step-up	no	$319,788	10	$37,622
15/20/25	115	12.47		step-down	LTC	$819,596	25	$38,569
25/33	138	13.2			LTC	$814,906	33	$29,052
25/33/42	161	24.94			LTC	$995,302	42	$27,880
25/33/42	115	12.47		step-down	LTC	$992,370	42	$27,797
39/52/65	138	34.5			LTC	$1,112,482	65	$20,135
50/66/83	138	67	12.47	Auto	LTC	$1,701,471	83	$24,117
60/80/100	161	69	13.8	Auto	DETC	$966,177	100	$11,367
67/90/112	138	34.5	12.47	Auto	LTC	$1,555,059	112	$16,335

We reviewed a number of recent interconnection proposals for new substations or substation expansions and noted that in a few instances the TFO provided segregated information for transformation costs. While many of the interconnection proposals contained proposals for larger transformers, the costs were typically not provided in enough detail to segregate transformation costs. Table 3 below shows the data obtained.

Table 3 - Interconnection Proposal Cost Data

MVA	HV	LV	Tap Chgr	Price	Size	$/MVA	Date	Source
45/60	138	13.8	LTC	$1,650,000	60	$27,500	30-Nov-06	ATCO Electric, Procter & Gamble Substation (808S) Interconnection Proposal, p. 6
15/20/25	144	25	LTC	$825,240	25	$33,010	30-May-06	ATCO Electric, Substation Capacity Upgrade, Cranberry Lake, 827 S, p. 16
15/20/25	138	25	LTC	$826,389	25	$33,056	24-Mar-06	AltaLink, Namaka 428S Transformer Addition, Interconnection Proposal, p. 12 & 24
22/33/42	138	25	LTC	$992,113	42	$23,622	21-Mar-06	AltaLink, Acheson 305S Substation Upgrade, Interconnection Proposal, p. 17

We are of the view that these unit costs are likely higher as some installation costs may have been included. We do not believe that a larger transformer will have significantly higher installation costs to warrant a higher incremental cost function equation.

This evidence suggests that incremental transformation costs above 25 MVA are about $10,000 to $30,000/MVA. These values are significantly less than the AESO's recommended Cost Function that proposes incremental costs of $154,000/MW for all interconnections above 7.5 MW.

1.3 PROPOSED COST FUNCTION

The above analysis and our experience in Alberta suggests that both transmission line and substation costs do not continue to increase with size over 30 MW at the same rate as the AESO data suggests for POD capacities above 7.5 MW. We are of the view that the proposed AESO Recommended Cost Function should recognize the economies of scale for larger capacity interconnections above 40 MW, as we believe the Board contemplated in its directive.[22]

In our view the cost function for larger PODs should have a slope that is less than $154,000/MW (incremental transmission line and substation costs). Further, the slope should be less than $122,000 MW for substation data only.[23] Based on the above analysis and the transformation cost evidence for larger transformers, we recommend that the slope of the cost function above 40 MW should be $30,000/MW.

The following Figure 7 shows our recommendations.[24] Theoretically, we hypothesize that the actual cost function is more likely a curve, as suggested by the red dashed line and the better fit logarithmic equation to correlate substation costs to DTS Contract Capacity.

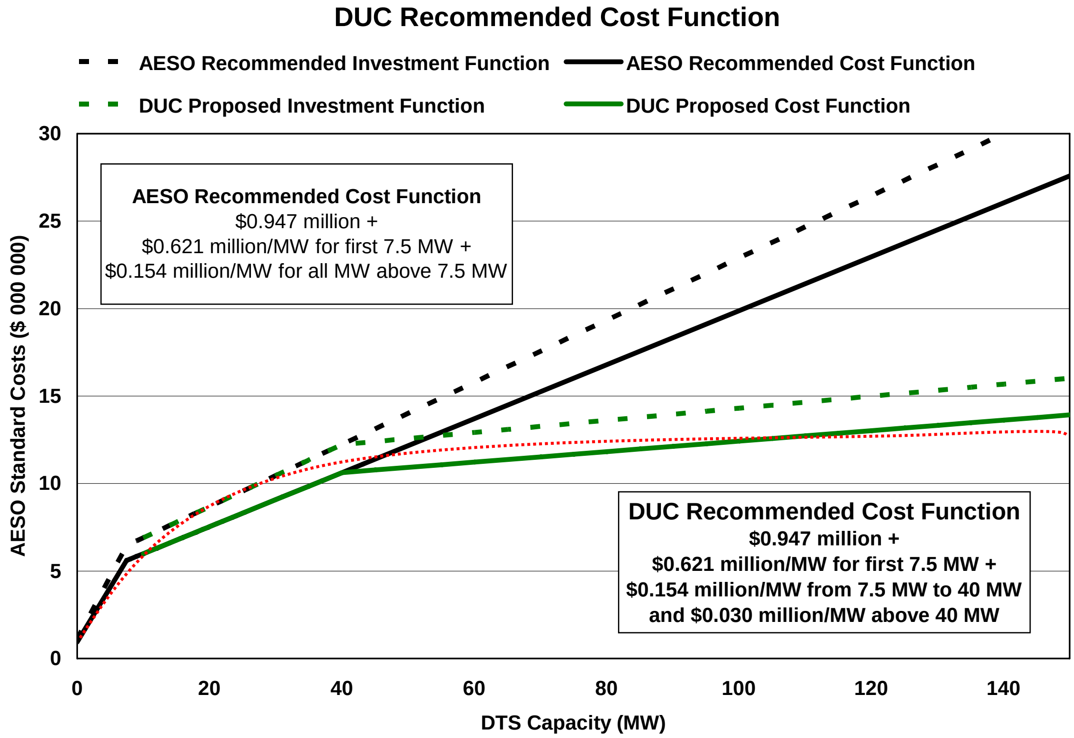
---

[22] Decision 2005-095, p. 58, item 2.

[23] Slope of the best fit linear equation for substation costs only.

[24] DUC POD PSC Evidence App G Revised.xls, tab Revised Cost Function

Figure 7 - DUC Recommended Cost Function



Our recommendation is based on the following:

- There is no correlation between incremental transmission line extension costs and POD size (see Figure 4 and Figure 5 above).
- The average cost of transmission line extensions for the AESO's Greenfield projects sample set is about $1.5 million[25] and the average cost of the AESO's Radial Line Costs sample set is about $2.0 million[26], with both sets of data showing no correlation to POD size.
- At a POD size above 40 MW, transmission line costs should be fully recovered under the AESO Recommended Cost Function ($10.6 million)[27] and there is no AESO evidence to suggest that transmission line costs will increase with POD size above 40 MW.

[25] The average cost as noted on Figure 5.

[26] AESO Attachment to TCE.AESO-025.xls, tab DTS and Line, average of column D

[27] DUC POD PSC Evidence App G Revised.xls, tab All Projects, Cells M18:O19

- The transformer cost data suggests that incremental transformation costs are under $30,000/MW for transformers above 25 MVA.

- Since the AESO Recommended Cost Function is based on the provision of a standard service (one transformer), incremental substation costs above 40 MW should be limited to transformation as no additional breakers or other major equipment items would be included in the standard service cost (all other costs are deemed optional facilities and are paid for by the customer).

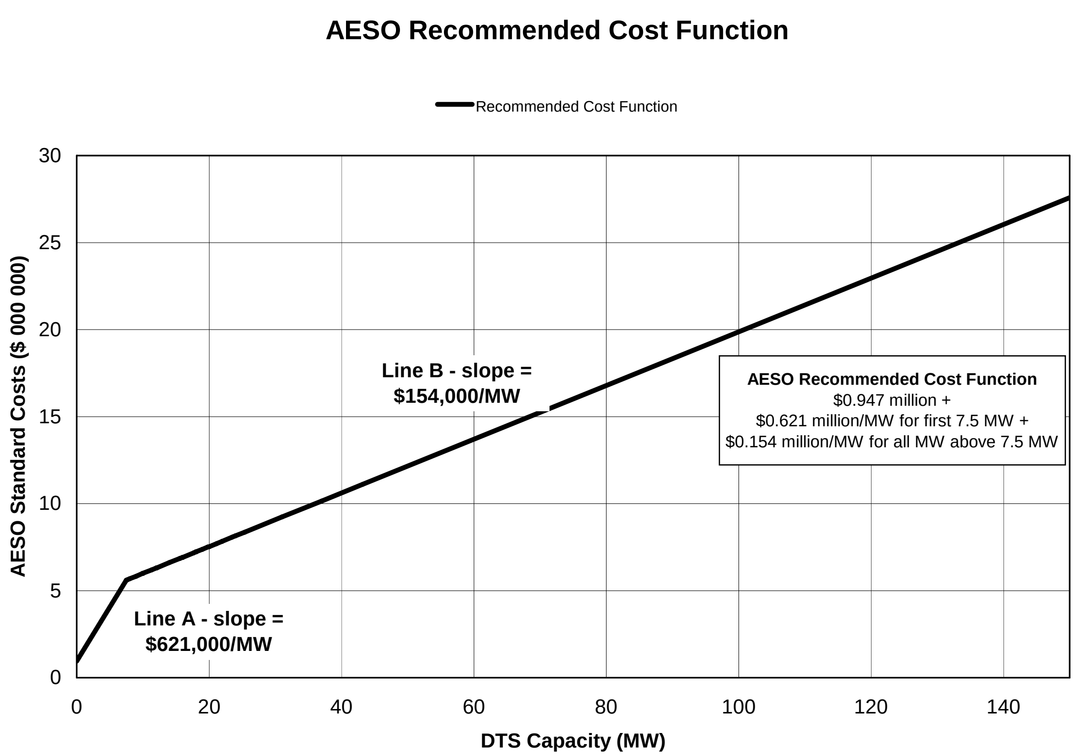
- The additional information provided suggests that incremental transformation costs are under $30,000/MW for transformers above 25 MVA, therefore we recommend a cost function with an incremental cost of $30,000 above 40 MW.

2.0 POINT OF DELIVERY RATE DESIGN

Our recommended cost function should be applied to the AESO's proposed POD rate design. This can be accomplished by adding a fourth component to the POD charge and adjusting the rates to collect the $188.6 million revenue requirement allocated to the wires related POD costs.[28]

The AESO used the slopes of their Recommended Cost Function to allocate wires related costs between the Billing Capacity Charges for under and over 7.5 MW.[29] The AESO used the slopes of Line A and Line B, as shown on Figure 8, for their allocations.

Figure 8 - AESO Recommended Cost Function with Line Slopes



The AESO prorated the non-wires costs based on the wires cost allocations.[30] We used the same approach to allocate costs over the three proposed Billing Capacity Charges

[28] Schedule 5.5, lines 5-7, col C

[29] Schedule 5.5, lines 5-6, col A

[30] Schedule 5.5, lines 5-6, col B

(under 7.5 MW, 7.5 to 40 MW and over 40 MW), using the slopes of Lines A, B and C, as shown on Figure 9.

Figure 9 - DUC Recommended Cost Function with Line Slopes

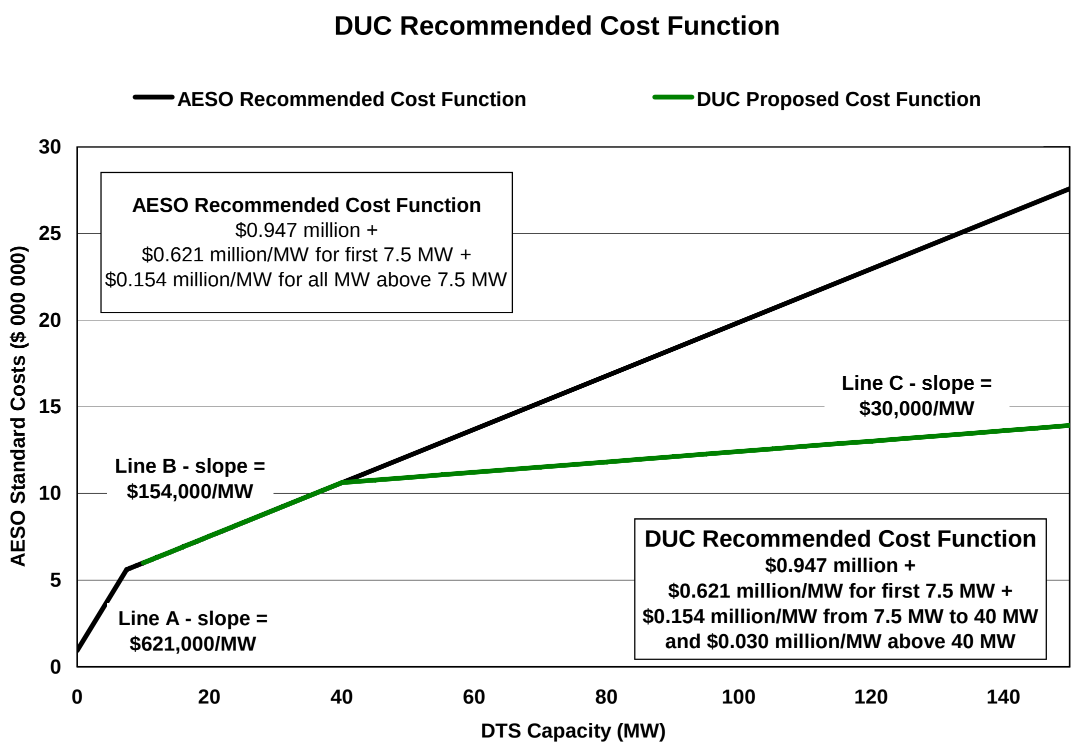


Table 4 shows the results.[31] Since we do not have access to the AESO's 2007 forecast of billing determinants, we estimated the number of MW-months in each of the three rate blocks which total the AESO's estimate of 114,648 MW-months for 2007.[32] Using 2006 billing data provided in response to BR.AESO-003, we allocated the AESO's forecast of 82,113 MW-months over 7.5 MW to 58,521 MW-months (71.3%) for 7.5 to 40 MW and 23,613 MW-months (28.7%) for over 40 MW.[33] If our recommendations are accepted by the Board, we anticipate that the AESO will be able to refine these values in their re-filing.

[31] DUC POD PSC Evidence Sched 5 Revised.xls, tab 5.5 DTS Rate

[32] DUC POD PSC Evidence Sched 5 Revised.xls, tab 5.9 Determinants

[33] DUC POD PSC Evidence BR 3 Expanded.xls, tab BR-003 (a)-A3 Per Pod, columns AB to AG

Table 4 - DUC Revised Schedule 5.5

Alberta Electric System Operator
AESO 2007 General Tariff Application

Rate Calculations
Schedule 5.5
November 3, 2006

DUC Revised
2007 Rate Calculations
Demand Transmission Service Rate Calculation

			A	B	C	D	E	F	G	H	I
Line		Sch 5.4	Costs, $ 000 000			Billing Determinant		Rate			
No.	Description	Reference	Wires	Non-Wires	Total	Quantity	Unit	Wires	Non-Wires	Total	Unit
1	**DTS System Charge**										
2	Billing Capacity Charge	Lines 4, 7-10	135.1	4.8	139.9	118,929.4	MW-months	$ 1,136.00	$ 40.00	$ 1,176.00	/MW
3	Flat Usage Charge	Lines 4, 7-10	127.9	4.7	132.6	54,682.5	GWh	$ 2.34	$ 0.09	$ 2.42	/MWh
4	**DTS POD Charge**										
5	Billing Capacity Charge ≤ 7.5 MW	Lines 5, 7-10	107.9	3.8	111.7	32,514.8	MW-months	$ 3,318.00	$ 117.00	$ 3,435.00	/MW
6	Billing Capacity Charge > 7.5 MW & ≤ 40 MW	Lines 5, 7-10	48.2	1.7	49.9	58,520.7	MW-months	$ 823.00	$ 29.00	$ 852.00	/MW
6a	Billing Capacity Charge > 40 MW	Lines 5, 7-10	3.8	0.1	3.9	23,612.6	MW-months	$ 160.00	$ 6.00	$ 166.00	/MW
7	Customer Charge	Lines 5, 7-10	22.4	0.8	23.1	4,854.4	customer-months	$ 4,605.00	$ 157.00	$ 4,762.00	/month
8	**DTS Operating Reserve Charge**										
9	Varying Usage Charge (Note)	Line 17	125.2	-	125.2	54,682.5	GWh	3.33%	-	3.33%	× Pool Price
10	**DTS Voltage Control (TMR) Charge**										
11	Flat Usage Charge	Line 18	50.8	-	50.8	54,682.5	GWh	$ 0.93	$ -	$ 0.93	/MWh
12	**DTS Other System Support Services Charge**										
13	Highest Metered Demand Charge	Line 22	7.8	-	7.8	101,353.4	MW-months	$ 77.00	$ -	$ 77.00	/MW
14	**Total DTS Cost Recovery**		**$ 629.0**	**$ 15.9**	**$ 644.9**						

Note: The 2007 forecast pool price is $68.75/MWh

Based on the above allocations our recommended 2007 DTS rate POD Charges are as follows:

(a) $3,435.00/MW/month for the first 7.5 MW of Billing Capacity in the Billing Period, multiplied by the Substation Fraction, plus
(b) $852.00/MW/month for the next 32.5 MW of Billing Capacity in the Billing Period, plus
(c) $166.00/MW/month for all Billing Capacity over 40 MW in the Billing Period, plus
(d) $4,762.00/month in the Billing Period, multiplied by the Substation Fraction.

For the purposes of comparison, the AESO's proposed 2007 DTS rate POD Charges are as follows:

(a) $3,129.00/MW/month for the first 7.5 MW of Billing Capacity in the Billing Period, multiplied by the Substation Fraction, plus
(b) $776.00/MW/month for all Billing Capacity over 7.5 MW in the Billing Period, plus
(c) $4,762.00/month in the Billing Period, multiplied by the Substation Fraction.

2.1 DUC POD RATE DESIGN IMPACT

As the above indicates, if one compares our proposed changes to the POD rate design to the AESO's proposed 2007 DTS rate, our proposal will result in a relatively small change to the average AESO customers' bill. The Figure 10 histogram shows that the vast majority of AESO customers will see an average monthly bill change from -10% to plus 6%:[34]

Figure 10 - Distribution of Bill Increases from AESO Proposed 2007 DTS Rate to DUC Proposed 2007 DTS Rate

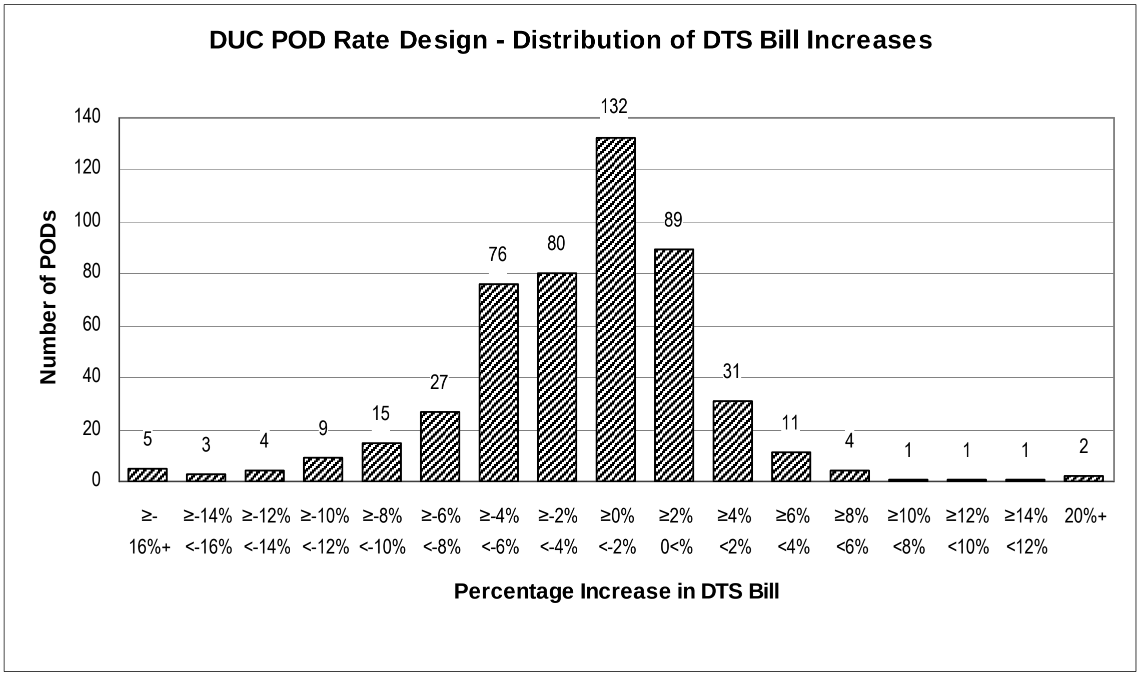


Table 5 shows that the impact of the proposed POD rate design on customers under 5 MW will be on average 7.2%, whereas the largest customers over 50 MW will see an average 2.7% reduction, compared to the AESO's proposed 2007 DTS rate.[35]

[34] DUC POD PSC Evidence BR 3 Expanded.xls, tab BR-003 (a)-A2 Distribution. Same format as provided by the AESO.

[35] DUC POD PSC Evidence BR 3 Expanded.xls, tab BR-003 (a)-A1 Summary. Same format as provided by the AESO.

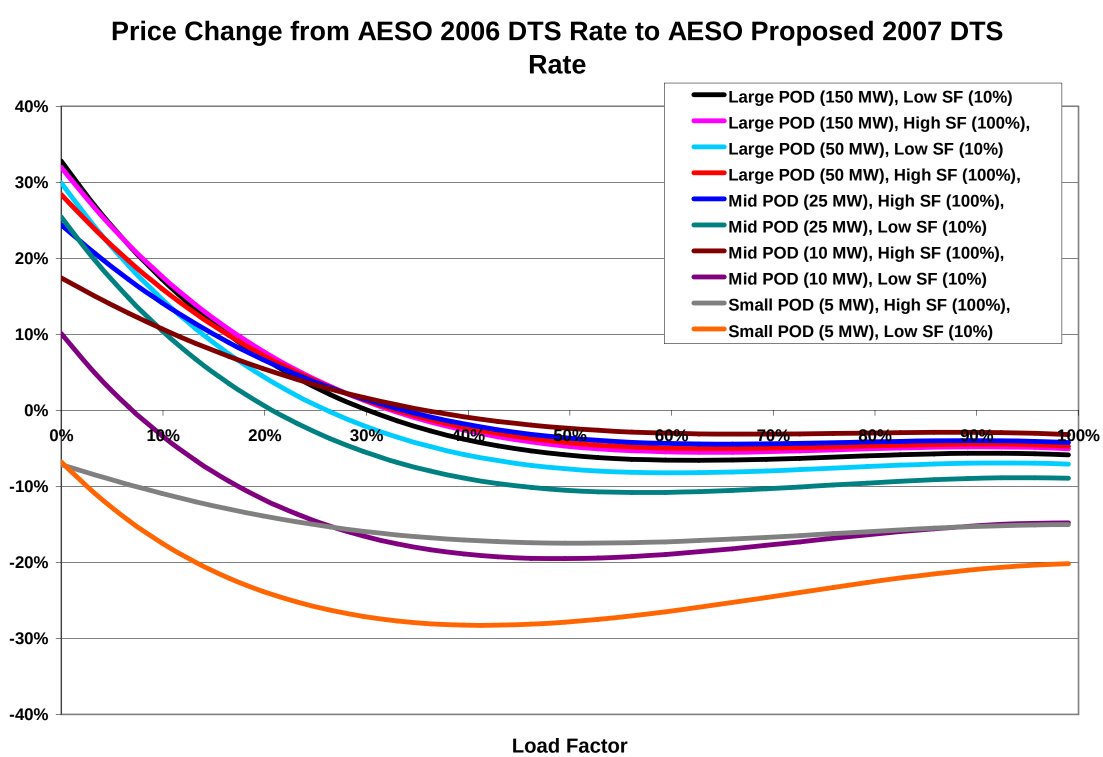
Table 5 - Impact of Bill Increases from AESO Proposed 2007 DTS Rate to DUC Proposed 2007 DTS Rate

Impact of DUC POD Rate Design Recommendations
Summary of Average Per-POD DTS Monthly Bill Impacts for DTS Charges

Description	Billing Capacity (MW)						Total
	0 to <5	5 to <10	10 to <17	17 to <25	25 to <50	50 to 180	
Number of Accounts	101	92	100	65	82	51	491
AESO 2007 Proposed	$11,860	$48,667	$78,321	$110,373	$179,388	$381,118	$111,667
DUC 2007 Recommended	$12,718	$51,434	$80,107	$109,942	$179,716	$370,949	$111,667
DUC Increases ($)	$858	$2,767	$1,786	-$431	$328	-$10,169	$0
DUC Increases (%)	7.2%	5.7%	2.3%	-0.4%	0.2%	-2.7%	0.0%

Figure 11 shows the impact of the AESO's proposed 2007 DTS rate compared to the current 2006 DTS rate for different sized customers and substation fraction (SF) levels over a range of load factors:[36]

Figure 11 -Price Change from AESO Proposed 2007 DTS Rate to AESO 2006 DTS Rate



The types of customers in the figure legend are sorted from the highest rate impact to the lowest at 0% load factor (left side of the figure). One can see that under the AESO's

[36] DUC POD PSC Evidence Rate Comparisons.xls, tab 2007 DTS vs 2006 DTS Chart

proposed 2007 DTS rate design, the larger the customer and the lower the load factor the higher the price increase.

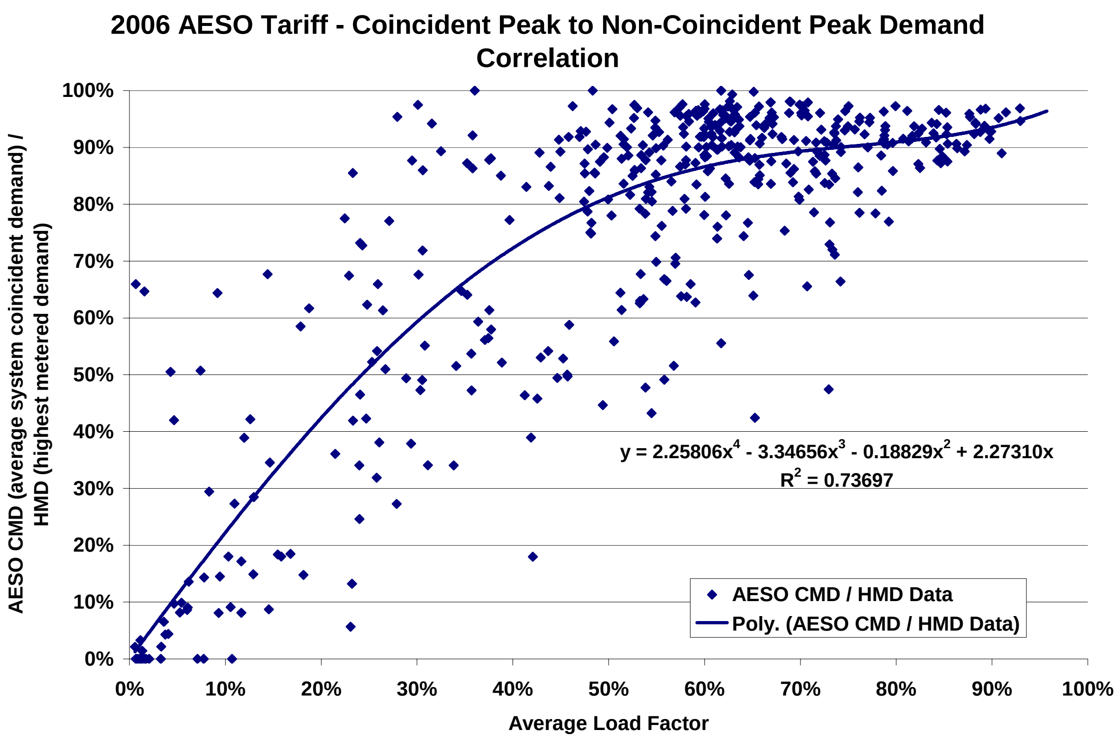
The majority of the price increases shown on Figure 11 for larger sized PODs stem from the AESO's Recommended Cost Function that overstates interconnection costs for larger PODs, which results in higher POD Charges.

The majority of the price increases shown on Figure 11 for low load factor customers stem from the AESO's proposed change from the 12 CP to the NCP / A&E allocation methods for DTS bulk system charges. This is a result of there being a greater probability that a customer will be able to avoid the system peak under a CP allocation method at a lower load factor. This analysis is valid for industrial customers whose monthly CP is likely not correlated to system peaks caused by residential and commercial electricity consumption patterns.

We have used the AESO's ratio of CMD (average system coincident demand) / HMD (highest metered demand) to correlate CP and NCP / A&E values, as shown in Figure 12.[37] A polynomial equation with five degrees of freedom and no intercept was used to correlate CMD / HMD to average billing load factor using the 2006 billing data the AESO provided in response to BR.AESO-003 (b)-A3. The R^2 statistic of 74% suggests a reasonably good fit of the data to the equation.

[37] DUC POD PSC Evidence BR 3 Expanded.xls, Tab CP NCP Correlation. Plot of CMD/HMD vs. load factor from AESO.BR-003 (a)-A3

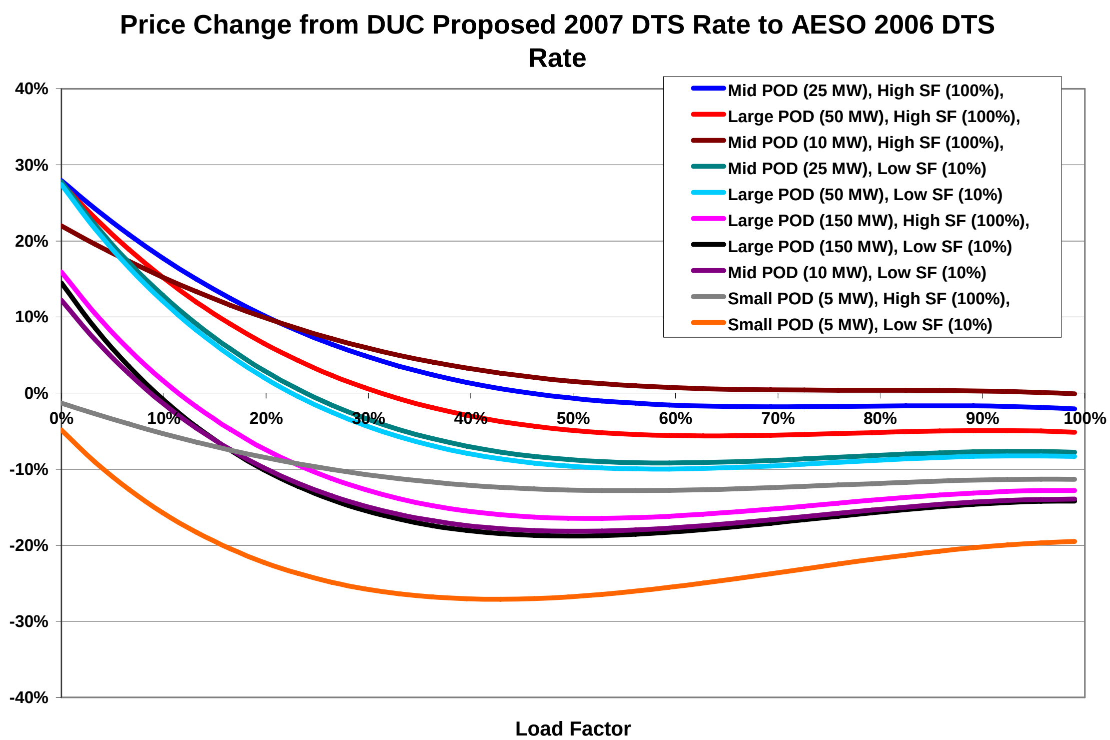
1 Figure 12 – Correlation of AESO Average Coincident Peak Demand / Highest Metered Demand vs. Average Load
2 Factor



3 Figure 13 shows the price impact from our recommended 2007 DTS rate, with the
4 modified POD charges, compared to the current 2006 Tariff DTS rate.[38]

[38] DUC POD PSC Evidence Rate Comparisons.xls, tab DUC 2007 DTS vs AESO 2006 Chart

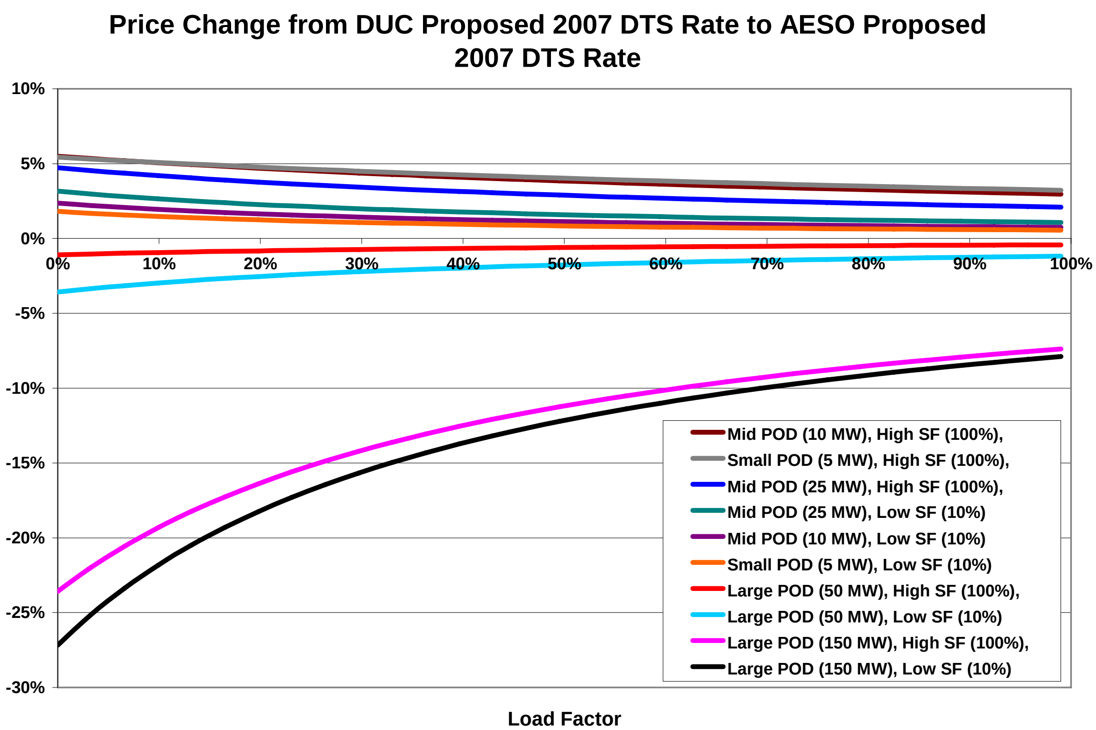
Figure 13 - Price Change from DUC Proposed 2007 DTS Rate to AESO 2006 DTS Rate



With the types of customers in the figure legend sorted from the highest rate impact to the lowest, one can see that under our proposed rate design price impacts are slightly muted (the range of price increase are lower than Figure 11) and POD size is no longer the predominate factor for the largest price increases.

Figure 14 shows the price difference between the AESO's proposed 2007 DTS rate and our proposed 2007 DTS rate (with the proposed changes to the POD charges).

Figure 14 - Price Change from DUC Proposed 2007 DTS Rate to AESO Proposed 2007 DTS Rate



The larger PODs are recommended to see a lower price than the AESO's proposed 2007 DTS rate in recognition of the lower cost to interconnect larger PODs to the grid. The price difference declines at higher load factors. The smaller PODs (under 40 MW) are proposed to receive small price increases from the AESO's 2007 DTS rate proposal.

3.0 CONTRIBUTION POLICY

Our recommended cost function should also be applied to the AESO's proposed investment policy in the same manner as the AESO has applied its Recommended Cost Function. This will ensure that the DTS rate is appropriately aligned with the rest of the tariff. In the same manner that the AESO's proposed investment policy flows from the AESO's Recommended Cost Function,[39] our recommended investment levels flow from our recommended cost function:[40]

AESO Recommended Cost Function

Break at	7.5	MW
	$0.947	million
plus	$0.621	million/MW for First 7.5 MW
plus	$0.154	million/MW for Remaining MW

AESO Recommended Investment Function

	$1.090	million x Substation Fraction
plus	$0.716	million/MW for First 7.5 MW x Substation Fraction
plus	$0.178	million/MW for Remaining MW

AESO Recommended Investment Function per Year of 20-Year Contract Term

	$54,500	/year x Substation Fraction
plus	$35,800	/MW/year for First 7.5 MW x Substation Fraction
plus	$8,900	/MW/year for Remaining MW

DUC Recommended Cost Function

Break at	7.5	MW
	$0.947	million
plus	$0.621	million/MW for First 7.5 MW
plus	$0.154	million/MW for the next 32.5 MW
plus	$0.030	million/MW for Remaining MW

DUC Recommended Investment Function

	$1.090	million x Substation Fraction
plus	$0.716	million/MW for First 7.5 MW
plus	$0.178	million/MW for the next 32.5 MW
plus	$0.035	million/MW for Remaining MW

DUC Recommended Investment Function per Year of 20-Year Contract Term

	$54,500	/year x Substation Fraction
plus	$35,800	/MW/year for First 7.5 MW x Substation Fraction
plus	$8,900	/MW/year for the next 32.5 MW
plus	$1,700	/MW/year for Remaining MW

[39] From Appendix G spreadsheet, tab All Projects, cells A73:F88 (also DUC POD PSC Evidence App G Revised.xls, tab All Projects, cells A73:F88)

[40] DUC POD PSC Evidence App G Revised.xls, tab All Projects, cells A90:F107

We recommend that our proposed investment levels be incorporated into Article 9.6 (a) (i) of the AESO's Terms and Conditions of Service.

We have considered whether the proposed maximum investment levels will provide sufficient investment to meet the test that 80% of new interconnections will not require a capital contribution for new interconnections or expansion greater than 40 MW. In most instances, large substations over 40 MW would require multiple transformers. With more than one transformer, substations costs increase as additional breakers and other equipment is required. However, the AESO's definition of a standard service is a single transformer and associated equipment.[41]

We also note that some of the newer and larger interconnections are associated with Industrial Systems where the customer has provided their own substation(s). We anticipate that at least in the near to medium term many of the new large interconnections will be associated with oilsands developments and many will likely seek an Industrial System Designation. In these cases the Maximum Investment amounts are less likely to be fully utilized for PODs over 40 MW as customers will be paying the full cost for the substations.

Given that the investment policy is applied to the standard level of service (one transformer), we are of the view that our recommended investment levels will satisfy the test that 80% of new large interconnections over 40 MW will not pay a contribution on the standard facilities.

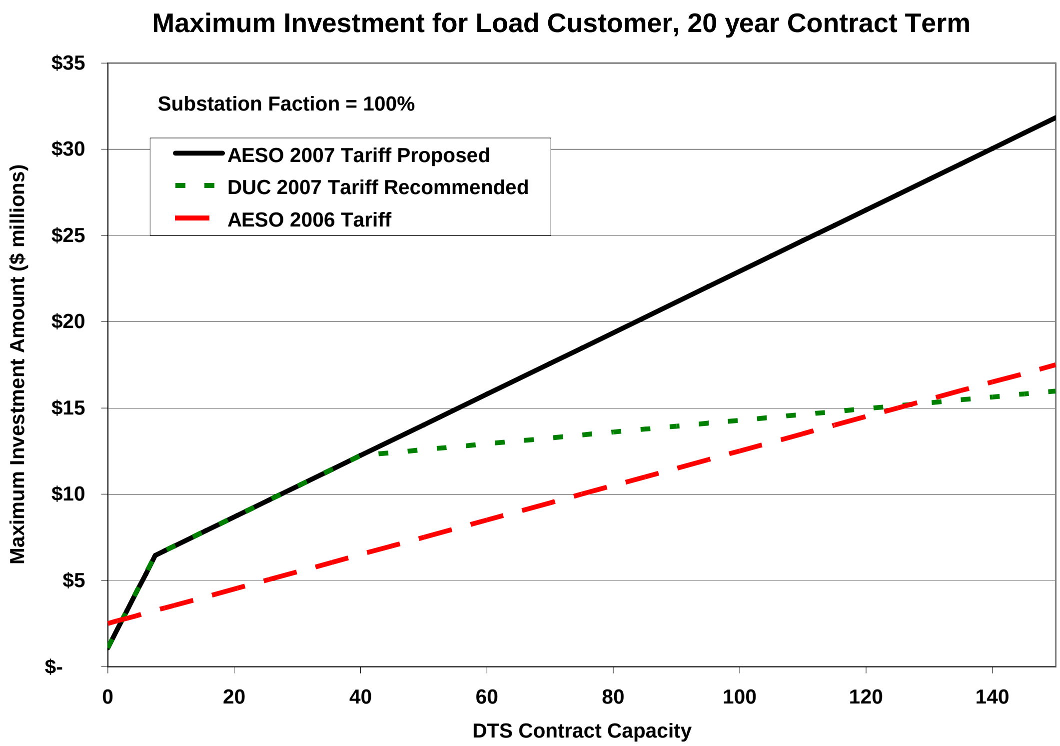
Figure 15 shows the AESO existing, AESO proposed, and DUC recommended investment levels for a new load only interconnection (100% substation fraction) where the customer executes a 20 year contract.[42]

---

[41] See footnote 17

[42] DUC POD PSC Evidence App G Revised.xls, tab Investment Level Chart, with cell C2 set to 100% on DUC POD PSC Evidence App G Revised.xls, tab Investment Levels

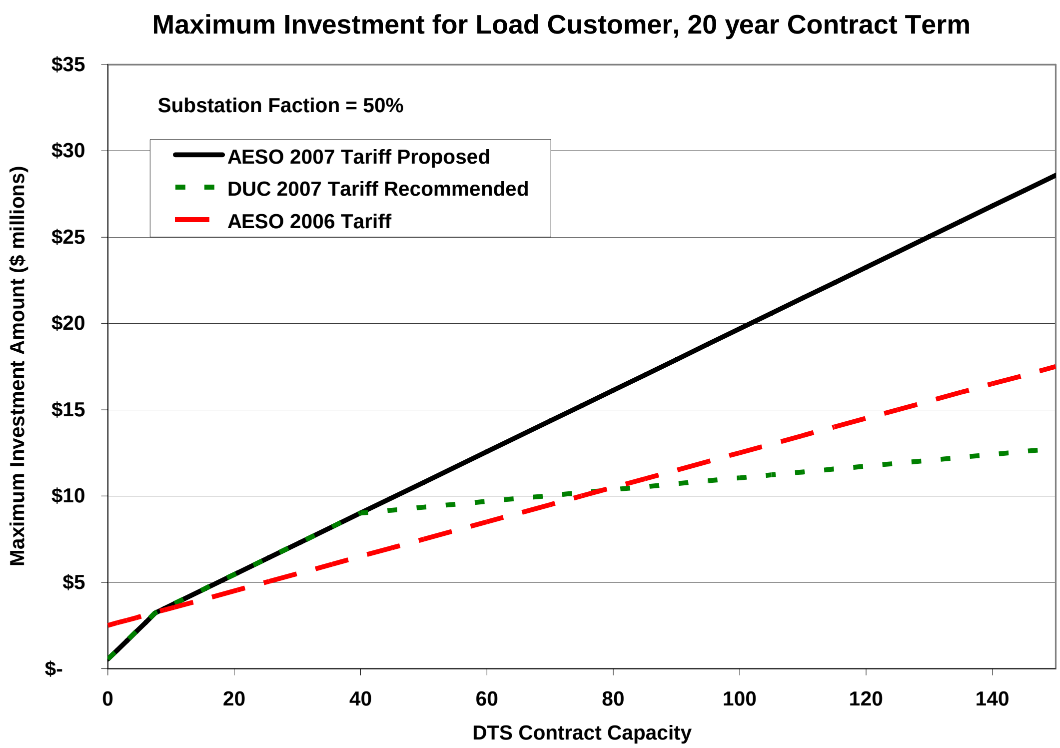
Figure 15 - DUC Recommended Investment Function – 100% Substation Fraction



At a 50% substation faction (load and generation the same size), the maximum investment levels are reduced as shown in Figure 16.[43]

[43] DUC POD PSC Evidence App G Revised.xls, tab Investment Level Chart, with cell C2 set to 50% on DUC POD PSC Evidence App G Revised.xls, tab Investment Levels

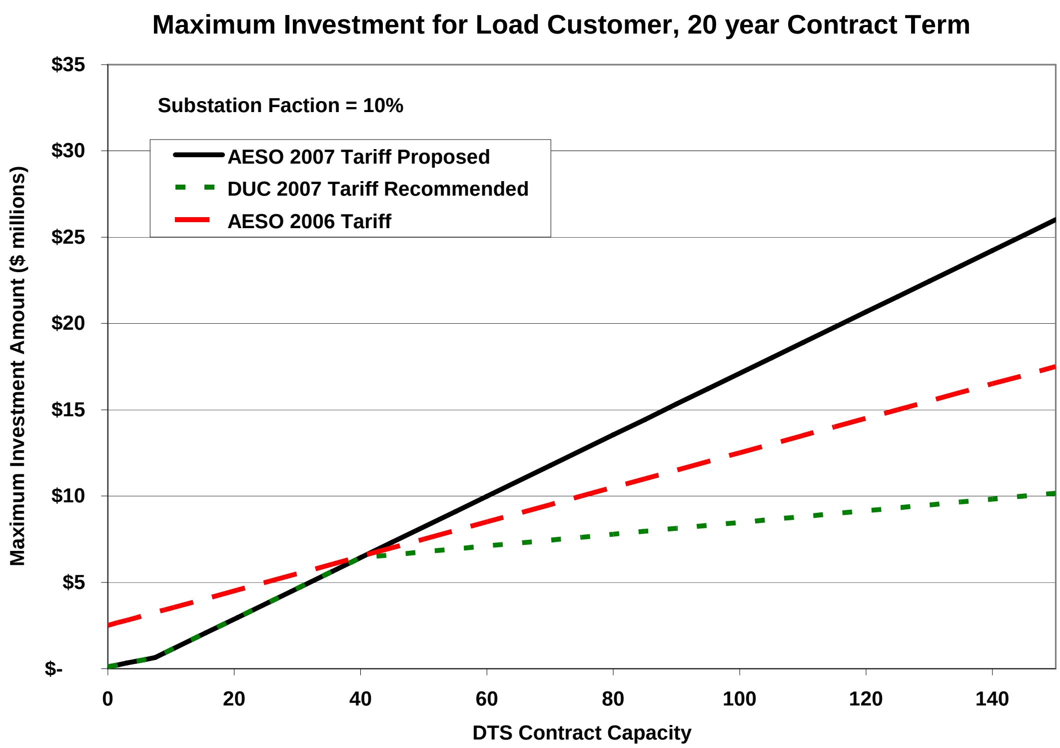
Figure 16 - DUC Recommended Investment Function – 50% Substation Fraction



It should be noted that the current contribution policy investment amounts are not reduced based on substation fraction. Under the AESO's and our proposed maximum investment levels, a generation customer with a small amount of DTS contract capacity (Substation Fraction = 10%) would receive lower maximum investment amounts, as shown in Figure 17.[44]

[44] DUC POD PSC Evidence App G Revised.xls, tab Investment Level Chart, with cell C2 set to 10% on DUC POD PSC Evidence App G Revised.xls, tab Investment Levels

1 Figure 17 - DUC Recommended Investment Function – 10% Substation Fraction



4.0 PRIMARY SERVICE CREDIT

The AESO has proposed that the PSC should be reduced from $660/MW/month and set at 40% of the POD charges.[45] In our view, the AESO's interconnection cost data (which is limited to substations under 30 MW) does not support this determination for the avoidance of transformation related costs.

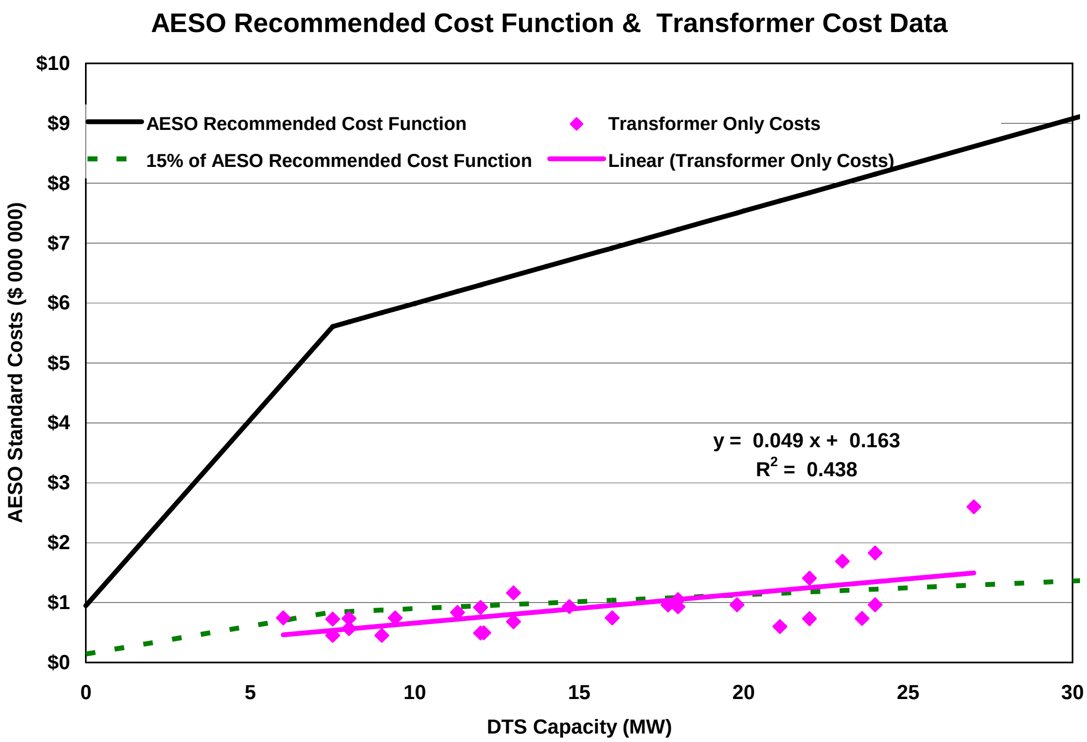
The AESO provided interconnection cost data for 28 projects that included total substation costs, transformation costs and breaker costs.[46] Plotting the transformer costs provides an indication of the total cost of transformation where the customer owns and paid for the transformer(s). Figure 18 shows that 15% of the AESO's Recommended Cost Function aligns with the best fit line for the transformer costs data points.[47]

[45] Application s. 4.10, page 51 of 53, lines 15-21

[46] AESO Appendix G spreadsheet, tab Cost Data Subs 2007

[47] DUC POD PSC Evidence App G Revised.xls, tab Cost Function & Transformers

Figure 18 - AESO Recommended Cost Function & Correlation of Transformer Only Cost Data

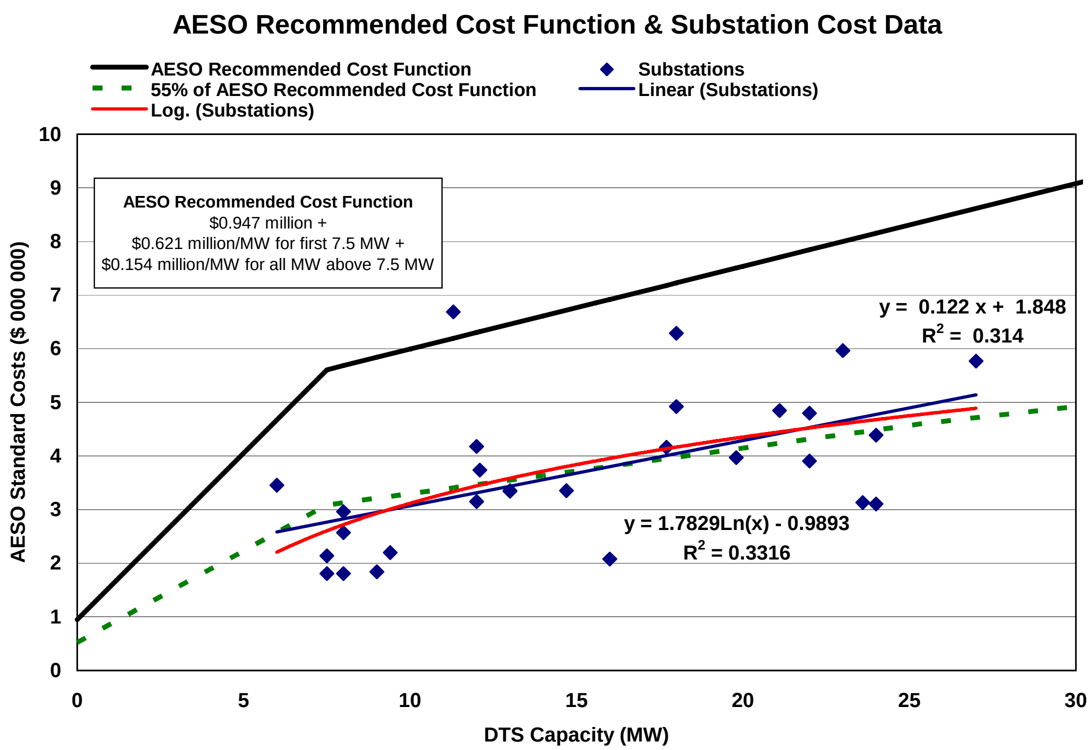


With the availability of better interconnection cost data and the proposed POD rate design we are of the view that the PSC should properly reflect the fact that most PSC customers have supplied not only their own transformers, but the entire substation.

The substation cost data suggests that 55% of interconnection costs are substation related. It therefore follows that for customers who own their own substations the PSC should be set at 55% of the POD charges, as shown in Figure 19.[48]

[48] DUC POD PSC Evidence App G Revised.xls, tab Cost Function with Subs Only

Figure 19 - AESO Recommended Cost Function & Correlation of Substation Only Cost Data



The AESO's proposed PSC is as follows (40% of AESO Recommended Cost Function):

(a) $1,252.00/MW/month for the first 7.5 MW of Billing Capacity in the Billing Period, multiplied by the Substation Fraction, plus
(b) $310.00/MW/month for all Billing Capacity over 7.5 MW in the Billing Period, plus
(c) $1,905.00/month in the Billing Period, multiplied by the Substation Fraction.

We recommend that the PSC be adjusted up to 40 MW for customers (if any) who only own their own transformers (15% of our recommended POD Charges):[49]

(a) $515.00/MW/month for the first 7.5 MW of Billing Capacity in the Billing Period, multiplied by the Substation Fraction, plus
(b) $128.00/MW/month for the next 32.5 MW of Billing Capacity in the Billing Period, plus
(c) $166.00/MW/month for all Billing Capacity over 40 MW in the Billing Period, plus
(d) $714.00/month in the Billing Period, multiplied by the Substation Fraction.

[49] DUC POD PSC Evidence Sched 5 Revised.xls, tab 5.5 DTS Rate, cells W14:W19

We also recommend that the PSC be adjusted be adjusted up to 40 MW for customers who own their substation (55% of our recommended POD Charges):[50]

(a) $1,889.00/MW/month for the first 7.5 MW of Billing Capacity in the Billing Period, multiplied by the Substation Fraction, plus
(b) $469.00/MW/month for the next 32.5 MW of Billing Capacity in the Billing Period, plus
(c) $166.00/MW/month for all Billing Capacity over 40 MW in the Billing Period, plus
(d) $2,619.00/month in the Billing Period, multiplied by the Substation Fraction.

For POD sizes over 40 MW, our recommended cost function is based on the premise that the only incremental cost element is transformation. Therefore we recommend that the PCS for Billing Capacity over 40 MW be set equal to our recommended POD charge for Billing Capacity over 40 MW ($166/MW/month).

4.1 PSC ELIGIBILITY

The AESO is proposing that the PSC be extended to ten Isolated Community and Unconventional Interconnection customers.[51] The AESO is forecasting annual PSC of $341 thousand to the eight Isolation Community customers and $46 thousand for two Unconventional Interconnection customers.

The AESO states under section 4 of its application at page 52 of 53:

> In addition to the level and structure changes, the AESO proposes that the eligibility criteria for the Primary Service Credit be refocused from whether the customer-owned transformation would have reduced TFO investment to whether the TFO owns conventional transformation equipment utilized in providing service to the customer. The AESO considers that such a change would appropriately accommodate the unconventional and “virtual” interconnections discussed in section 4.5.2 of this Application.

Under section 4.5.2, the AESO states at page 20 of 53:

> Some small loads represent “virtual” transmission services for the purpose of section 3(b) of the *Isolated Generating Units and Customer Choice Regulation*, whereby transmission charges are attributed to an isolated community “as if the isolated community were being provided with system access service via the interconnected electric system.” However, there is no physical transmission substation associated with the isolated community. If those communities were actually connected to the electric system their small capacities would likely lead

[50] DUC POD PSC Evidence Sched 5 Revised.xls, tab 5.5 DTS Rate, cells X14:X19

[51] Schedule CG.AESO-017 (b-c) page 2 of 2

to connection through a distribution network rather than directly to the transmission system as a stand-alone substation.

The *Isolated Generating Units and Customer Choice Regulation* states under s. 6(c):

> 6 The costs associated with providing electric energy to customers in an isolated community must be paid in accordance with the following:
>
> (c) the owner of the electric distribution system in whose service area the isolated community is located must pay the Transmission Administrator for system access service as if the isolated community were being provided with system access service via the interconnected electric system;

The AESO charges ATCO Electric at the Isolated Communities as if the sites were interconnected to the transmissions grid.

Section 6 (d) of the regulation states:

> (d) the Transmission Administrator must pay the owner referred to in clause (c) the costs associated with providing electric energy to an isolated community in accordance with the tariff approved by the Board pursuant to section 3(b);

The tariff from ATCO Electric to the AESO includes the revenue requirement associated with the isolated generation units, including capital recovery, maintenance and fuel costs. In our experience, the provision of electricity from remote generators has a full cost in excess of $250/MWh.[52]

While the tariff from ATCO Electric to the AESO for the isolated generation units excludes costs related to transmission substations (as there are none), the isolated generation unit costs are included. Costs per isolated generation site are on average over $2 million per year,[53] well in excess of the estimated DTS revenue of the $160,000 per year the AESO receives from each of these sites.[54]

In our view, the intent of the PSC is to recognize the financial contributions made by the PSC eligible customer and the corresponding avoided investment by TFOs. In the case of the isolated generation sites, we are not aware of any avoided investments due to ATCO Electric's requirement to invest capital in isolated generation plants.

---

[52] For example, ATCO Electric's 2007 TFO Filing shows forecast cost of $247/MWh excluding return on equity and debt costs (page 4-1 & Schedules 5-1, 5-6 & 6-6).

[53] ATCO Electric's 2007 TFO Filing shows forecast cost of over $18 million excluding return on equity and debt costs and Schedule CG.AESO-17 (b), page 2 of 2, shows a total of eight isolated sites.

[54] DUC POD PSC Evidence CG 17 Expanded.xls, tab CG-017 (b-c) PSC Details p2, cells M8:R22

We recognize that interconnecting these remote communities to the provincial grid would likely result in higher costs than continuing to operate the isolated generation units. However, in our view, this should not be the test for eligibility of the PSC. For dual-use customers, customers eligible for the PSC have chosen to decline investment by the AESO in necessary substation facilities and have incurred that expense on their own, thus increasing costs to themselves and benefiting all other AESO customers. In this case, transmission costs to other customers are lower, and fairness dictates that customers who own their own substations should receive a tariff cost reduction.

In the case of the isolated generation units, there is no cost saving choice. The lowest cost option, interconnection to the gird or isolation generation unit, is provided. There is no avoided investment that makes AESO customers better off, and hence their should be no tariff cost reduction (i.e. PSC) for the isolated generation PODs.

For the above reasons we recommend that the Isolation Community customers not be eligible for the PSC.

5.0 2006 PSC CUSTOMERS IMPACT ANALYSIS

The AESO is proposing that the quantum of the 2007 Primary Service Credits paid to the 2006 PSC eligible customers be reduced to $3.2 million. Our recommendations would increase the total to about $3.5 million. These are significant reductions from the $6.2 million paid under the AESO's 2006 tariff.[55]

The AESO is also proposing that the quantum of the 2007 POD charges be $8.1 million to the 2006 PSC eligible customers. Our recommendations would reduce the total to about $5.7 million. Our recommendation is a reduction from the $8.2 million paid under the AESO's 2006 tariff.[56]

Table 6 shows the impact of the proposed changes for PSC eligible dual-use customers by combining the recommended PSC and the POD charges:[57]

[55] DUC POD PSC Evidence CG 17 Expanded.xls, tab PSC, row 32

[56] DUC POD PSC Evidence CG 17 Expanded.xls, tab POD Charges, row 32

[57] CG.AESO-17 (b) spreadsheet revised to include our recommendations, see DUC POD PSC Evidence CG 17 Expanded.xls, tab POD + PSC Charges

Table 6 - POD + PSC Charges - Price Impact of AESO and DUC Proposed 2007 DTS Rate

POD Charges plus PSC

Substation	Derived Billing Capacity	Dual-Use Customer DTS MW	Dual-Use Customer STS MW	Other MW	2006 Annual POD*+PSC	Billing Capacity	Substation Fraction	AESO Proposed Monthly POD+PSC	AESO Proposed Annual POD+PSC	DUC Recommended Monthly POD+PSC	DUC Recommended Annual POD+PSC
2006 PSC Customers	2006 Actual					2007 Forecast					
Botha 758S	6.4	5.5	22.0	-	$56,174	6.1	0.20000	$2,861	$34,336	$2,314	$27,773
Brazeau Plant	16.4	18.5	-	359.2	22,137	16.7	0.04898	5,117	61,400	4,200	50,401
Calpine CES1	5.4	6.0	280.0	-	8,559	5.4	0.02098	273	3,271	220	2,641
Express Hardisty	2.7	4.6	-	-	264,323	6.5	1.00000	15,058	180,690	12,190	146,283
Exshaw	29.2	29.2	-	-	279,250	29.9	1.00000	27,373	328,475	22,324	267,890
Foster Creek	10.8	8.0	80.0	-	30,001	9.2	0.09091	2,332	27,981	1,901	22,806
Imperial Oil Cold Lake	97.6	40.0	67.0	-	153,302	97.4	0.37383	48,224	578,688	21,883	262,599
Keephills Blackstart	20.9	15.0	-	764.5	16,818	15.1	0.01924	3,867	46,409	3,178	38,137
MacKay River	10.8	9.5	157.0	-	21,103	11.0	0.05706	2,597	31,167	2,126	25,508
Medicine Hat	32.4	26.0	90.0	-	77,188	29.3	0.22414	13,954	167,454	11,437	137,243
Muskeg River	21.0	20.0	170.0	-	39,493	20.2	0.10526	7,701	92,409	6,315	75,780
Namaka	2.0	2.0	120.0	23.5	4,713	1.9	0.01375	88	1,060	70	838
Nexen #1	1.9	2.0	110.0	0.9	5,714	1.8	0.01771	110	1,325	87	1,047
NOVA Joffre #1	120.3	133.7	470.0	31.2	123,209	120.3	0.21060	56,131	673,574	21,352	256,221
Primrose	49.0	23.7	85.0	0.1	84,821	47.0	0.21764	22,093	265,111	15,973	191,675
Redwater Cogen	16.0	16.0	-	-	271,832	15.5	1.00000	20,663	247,950	16,803	201,639
Ruth Lake	20.0	15.3	100.0	11.6	43,031	35.2	0.12092	14,956	179,471	12,281	147,374
Shell Scotford	180.0	200.0	82.0	-	287,895	180.0	0.70922	92,395	1,108,743	32,660	391,924
Summerview	1.0	0.6	68.4	-	2,848	1.0	0.00870	41	494	32	385
Suncor #1 Standby	135.0	150.0	220.0	-	182,677	135.0	0.40541	66,280	795,365	25,126	301,509
Wabamun Standby	10.0	11.0	-	278.6	15,631	10.1	0.03798	1,855	22,257	1,519	18,222
Total 2006 PSC Customers	**788.9**	**736.6**	**—**	**—**	**$1,990,719**	**794.6**	**—**	**$403,969**	**$4,847,632**	**$213,991**	**$2,567,895**

Note: * Excluding the $0.08/MWh Energy Charge

The AESO is also proposing that the quantum of the 2007 PSC + POD charges be $4.8 million to the 2006 PSC eligible customers. Our recommendations would reduce the total to about $2.2 million. This is a 12% increase from the $2.0 million paid under the AESO's 2006 tariff.

In the spreadsheet entitled DUC POD PSC Evidence CG 17 Expanded.xls there are figures that show unit costs ($/MW/month) for PSC, POD and PSC + POD charges.[58] These charts show that the POD $/MW/month charges under the AESO's proposed 2007 tariff and the DUC's recommendations are similar for customers over 40 MW, assuming that the customer owns the entire substation. The DUC's POD charges are similar for customers under 40 MW and lower for customers over 40 MW compared to the AESO's tariffs. Interestingly, combining the PSC and POD charges results in the AESO's 2006 Tariff and the DUC's recommendations providing similar $/MW/month charges for customers over 30 MW.

[58] DUC POD PSC Evidence CG 17 Expanded.xls, tab PSC Chart, POD Charge Chart and PSC + POD Charges Chart. The substation fraction can be adjusted by changing the value in cell C4 on tab Per MW Change.

APPENDIX – NOTES ON SPREADSHEETS PROVIDED

The spreadsheets noted in the middle column of Table 7 below are provided to support this evidence:

Table 7 – DUC Spreadsheets

Original Source	DUC Spreadsheet Name	Purpose
AESO Application Appendix G spreadsheet 2006-11-03 AESO 2007 GTA - G Contribution Study Data.xls	DUC POD PSC Evidence App G Revised.xls	Review the AESO data to proposed a revised cost function and contribution policy amounts
BR.AESO-003 attachment spreadsheet 2007-02-26 AESO 2007 GTA - IRs Att BR.AESO-003 (a)-A Rev - DTS Impacts - As Filed.xls	DUC POD PSC Evidence BR 3 tabs Expanded.xls	Review the 2006 billing determinants
AESO application spreadsheet 2006-11-03 AESO 2007 GTA - 5 Rate Calculations.xls	DUC POD PSC Evidence Sched 5 Revised.xls	Revised rate design for POD charges and PSC
	DUC POD PSC Evidence Rate Comparisons.xls	Show generic impact of DUC proposed POD charges and PSC
CG.AESO-017 attachment spreadsheet 2007-02-05 AESO 2007 GTA - IRs Att CG.AESO-017 (b-c) - PSC Details.xls	DUC POD PSC Evidence CG 17 Expanded.xls	Show impact of DUC proposed POD charges and PSC on 2006 PSC customers

The following conventions generally apply to the DUC spreadsheets:

- White colored tabs are from the Original Source, with additions and modifications made by the DUC in light turquoise highlight
- Blue colored tabs are worksheets added by the DUC
- Green colored tabs are figures added by the DUC

Each of the blue tabs in the spreadsheet DUC POD PSC Evidence Rate Comparisons.xls contains a macro that recalculates the Percent Increase / (Decrease) in column X for each of the scenarios in cells Z1:AI8. If these scenarios are altered and the button over cell X2 is depressed, the values in cells Z10:AI40 will be updated (the corresponding figures use the values in these ranges).