

**Alberta Transmission System
2006 Transmission Cost Causation Update
September 15, 2006**

**Prepared for the
Alberta Electric System Operator (AESO)**

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Table of Contents

1. Overview	2
2. Bulk System Demand Related Costs	3
2.1 Cost Causation Update Activities	6
2.2 Factors that Drive Bulk System Upgrades.....	8
2.2.1. Alberta Internal Load (AIL)	8
2.2.2. Interviews with Transmission Planners.....	9
2.2.3. Coincidence between Bulk System Load and AIL Load.....	13
2.2.4. Percent Loading based on Thermal Capacity	23
2.3 Threshold of Significant Correlation.....	29
2.4 Summary – Classification of Bulk System.....	31
2.4.1. Classification of Bulk System Costs.....	32
2.5 Contract Capacity	34
2.6 Stakeholder Input	36
3. Interprovincial Ties	40
3.1 NBV of Interprovincial Interconnections	41
3.2 Summary	41
4. Local System	42
4.1 Alignment With Contribution Policy.....	45
4.2 Conclusion	46
5. POD Costs	47
6. Refinements to the Cost Causation Study	48
6.1 Contributions in Aid of Construction (CIAC).....	48
6.2 Dual Use Substations	49
6.3 Impact of Refinements	52
7. Operations, Maintenance and Administration	54
8. Recommended Additional Activities	56
9. Appendix A	57

1. OVERVIEW

The AESO commissioned the study of cost causation within the transmission system in order to better understand costs, to assist with the design of the structure of the transmission tariff and to fulfill EUB directions to review costs. The Transmission Cost Causation Study (TCCS) was filed as part of the AESO 2005-2006 General Tariff Application. The EUB considered the report to be “a good first step” (Decision 2005-096, p. 24) at an in depth review of cost causation for an electric transmission system.

The AESO and various stakeholders identified several activities for further study, based in large part on directions and comments provided by the EUB in Decision 2005-096. The activities for further study as described in the Terms of Reference dated February 16, 2006, are provided in Appendix A.

This Transmission Cost Causation Update (TCCU) addresses several of the activities listed in the Terms of Reference found in Appendix A. Each activity has its own overview and summary.

2. BULK SYSTEM DEMAND RELATED COSTS

The Transmission Cost Causation Study identified Bulk System costs that were demand and energy related. The nature of the demand related costs and how they are incurred is the subject of this section. The TCCS defined a new term: Coincident Load at time of Maximum Stress (CLMS), because it was evident that the bulk transmission system is designed to meet the maximum stress on the Bulk System, rather than designed to meet the load only during the hour of annual Alberta Internal Load (AIL) peak load, the coincident peak load or CP.

The rationale for Bulk System additions is complex. Additions to the Bulk System are required when the Bulk System becomes stressed. In the AESO's 2005-2006 GTA, interveners suggested that demand related costs be classified on the basis of coincident peak demand to best reflect cost causation. This section tests the relationship between coincident peak load and maximum stress on the system.

Maximum stress in the Bulk System is a situation where transmission planning criteria are in violation, and an upgrade is required to alleviate the violation. Stress results when there is violation of limits with respect to one or more of the following parameters:

- Thermal capacity,
- Voltage,
- Stability

The electrical system is modeled on a forecast load basis and each of these parameters is tested to ensure compliance with planning criteria. Violation of thermal capacity is easiest to demonstrate as follows: A line has a thermal rating of 500 MVA in the winter, and 400 MVA in the summer. If the line is loaded at 450 MVA for the entire year, the line is at 90% of its thermal

capacity in the winter and is at 113% of its thermal capacity in the summer. This line experiences maximum stress in the summer even though its load is constant throughout the year.

Thermal capacity is easy to understand because each transmission component has a rating that can be compared to loading to see if there is an overload. Stress regarding voltage or stability is more difficult to understand because these parameters are determined through the interaction of a large number of transmission components. For example, low voltage can occur as the result of system conditions elsewhere on the system.

This study finds that for Alberta as a whole, the correlation between the time of maximum stress on the Bulk System and the hour of AIL peak system load is weak or non-existent. For most areas of Alberta, the time of maximum stress on the Bulk system does not coincide with the time of the annual peak system load. The northwest part of Alberta is the only area where the time of maximum stress on the Bulk system coincides with the time of peak system load.

The time of maximum stress on the Bulk System is driven by a number of variables including the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta. The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta. The maximum demand at each POD is a more appropriate indicator of contribution to stress on the Bulk System.

The Bulk System is planned to meet the demand for electricity throughout the year, and the issue at stake is what demand parameter is the best basis to classify demand related costs. The TCCS identified that costs are caused by stress on the Bulk System and that coincident load to maximum stress is the best means of classifying Bulk System demand related costs. However, coincident load to maximum stress is not a practical parameter because this

parameter changes depending on the location in the Bulk System. The two other most prominent options include the demand at the time of the AIL system peak (also known as the coincident peak or CP) and the maximum demand at each POD. The AIL system coincident peak (CP) demand has a very weak correlation to stress on the Bulk System and the peak demand at the POD's is assessed as a more reliable and predictable indicator of cost causation for the Bulk System.

2.1 Cost Causation Update Activities

The first area identified by the AESO for further study is the Bulk System, and specifically the time that the Bulk System is stressed as follows:

Study all of the major bulk paths (between 20 and 30 paths) to determine the relationship between the time of maximum stress and the time of peak system load. Review the functionalization of bulk system and local system to ensure continuing consistency with AESO planning. This study component would primarily use technical data from the 500 kV N-S Need Application as the basis, as well as additional data from more recent planning studies prepared by the AESO, if necessary.

The use of technical data from the 500 kV N-S Need Application is not practical because the Application did not provide data for lines in other areas. In order to study the relationship between maximum stress and system peak load, further research and other data sources are required.

A common hypothesis is that the Bulk System is most heavily loaded and stressed at the time of system peak load. This hypothesis has been the basis for classifying demand related costs of transmission to load on the basis of coincident peak load. The process of classifying all costs to the single annual coincident peak load is commonly referred to as 1 CP. Variations on this method of classifying costs include the classification of costs to each monthly coincident peak load. When each month is weighted equally, the method is known as 12 CP. Other variations include different weightings by month to allow heavier weights for months that planners focus on when determining the adequacy of the transmission system.

The TCCS studied the rationale for Bulk System upgrades, and determined there are times or conditions that contribute to maximum stress on the Bulk System, and the term Coincident Load at the time of

Maximum Stress (CLMS) was developed. The TCCS found that the CLMS was not necessarily coincident to the system peak load. In the case of the North-South 500 kV upgrade, the load on two paths was closest to the thermal rating of the path during light system load periods. The TCCS also identified that 55% of points of delivery experienced peak load conditions in the winter, and 45% experienced peak load conditions in other seasons.

Two paths were studied in the TCCS study, and participants are interested in a more in depth study of the correlation between the system load, and the conditions that drive Bulk System capital expansions.

The study of the correlation between system load and factors that drive Bulk System expansions is challenging, because there are several independent factors, identified in the previous section, that planners consider when determining the need for system upgrades. The following section studies factors that cause Bulk System upgrades.

2.2 Factors that Drive Bulk System Upgrades

This section explores the requirements to upgrade the Bulk System, and also tests the hypothesis that peak system load drives the need for Bulk System upgrades.

This study consists of the following three sections:

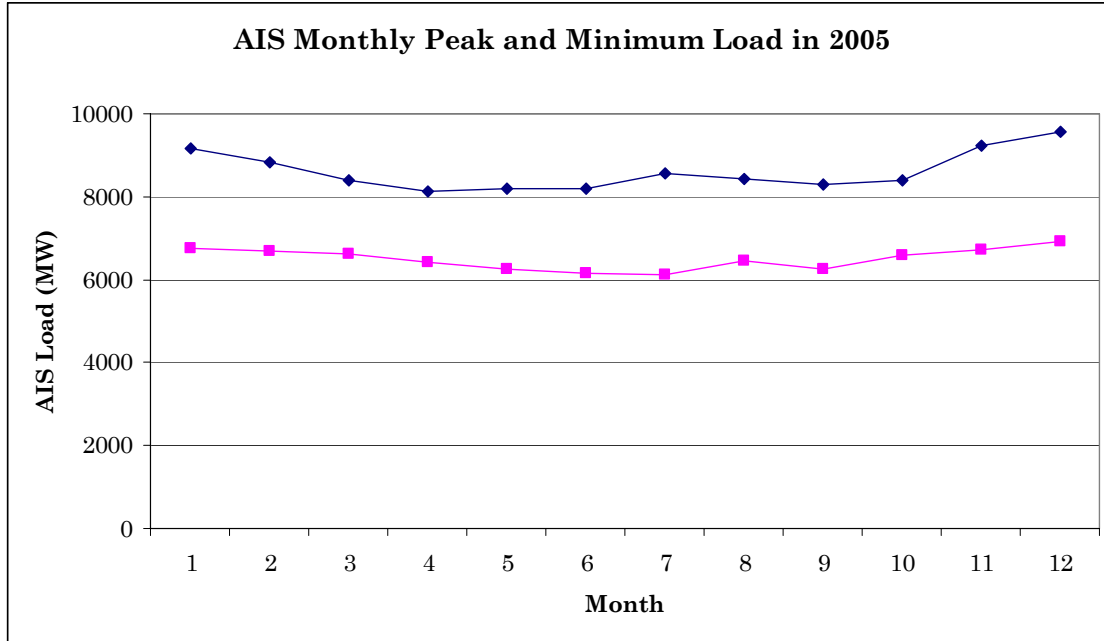
- a) Interviews with planners to review transmission paths and the need to upgrade the system to accommodate load growth,
- b) A study of correlation between loading on Bulk System components (240 kV lines) and AIL, and
- c) A study of correlation between line loading as percent of thermal capacity and AIL.

The correlation studies consider the number of lines, the kM of lines, and the Net Book Value (NBV) of the lines.

2.2.1. Alberta Internal Load (AIL)

Alberta Internal Load (AIL) represents the total domestic consumption of Alberta Interconnected Electric System (AIES) loads in Alberta. The AIL annual load profile in Alberta has changed over the years. In the past, Alberta had a strong winter peak load. With the addition of irrigation, air conditioning and industrial load, the winter peaks are no longer as dominant as they once were. Southern Alberta electrical load has become summer peaking load, and in combination with lower thermal capacity in the summer, the transmission system in southern Alberta is not thermally constrained in the winter time. The electrical load in Calgary and Edmonton peaks in the winter in some years, and in the summer in other years, depending on the weather. Overall in Alberta, the summer peak load in 2005 was approximately 90% of the winter peak load. The following chart shows the monthly peak load in Alberta for 2005.

Figure 1 Annual Load Profile of 12 Monthly Peaks



2.2.2. Interviews with Transmission Planners

During the AESO's 2005-2006 GTA proceeding, there was discussion of some 20 or 30 major transmission bulk paths that planners may consider when studying the transmission system. The transmission planners have no standard definition regarding what constitutes a transmission path. Transmission planners may consider cut planes as the lines that separate various regions. The flow across a cut plane is a function of the load and generation in a region, and the flow of electricity will take the path of least resistance and will flow in all lines crossing the cut plane. It is not possible to positively identify the precise number of major transmission paths and the loading in those paths because there is no universally applicable definition of a path. Transmission planners study a particular area and problem, and may consider a path a number of lines that have parallel flows, especially where outages to one line impact the flows on other lines in the path.

The transmission planners were interviewed to document transmission paths, and the time at which maximum stress occurs on the path, and the relationship between the time of maximum stress and the time of peak AIL load. The following table is a compilation of points that planners consider when studying the system to determine the adequacy of the transmission system to meet forecast load growth.

Table 1 Interviews with Transmission Planning Personnel

Description of Path or Transmission Facilities	Constraining Factor	Cause of Constraining Factor and correlation to AIL Peak Load
Southern Alberta		
944L/951L	Voltage and thermal capacity	Load plus export causes constraint. Load in area is primarily industrial (flat) and export to Saskatchewan varies. Export conditions independent of AIL.
923L/924L/911L South of Milo	Thermal capacity and voltage	Peak load conditions driven by wind power generation. Wind generation not correlated to AIL, thermal constraints occur in summer versus maximum AIL occurs in winter.
923L/924L west of Brooks	Currently under review	Coal fired generation from Sheerness and future Brooks plant plus wind generation. Coal is considered base load and wind generation will cause peak loading. Wind generation is not correlated to AIL.
SE Area 240 kV upgrade	Thermal capacity	Projected wind generation. Wind generation is not correlated to AIL, and thermal constraints will occur in summer.
933L/934L/950L South of Anderson	Under review	
SW Upgrade – Pincher Creek Area	Thermal capacity and voltage	Wind generation causes high loading. Wind generation not correlated to AIL. Thermal constraints will occur in summer versus maximum AIL in winter.

Description of Path or Transmission Facilities	Constraining Factor	Cause of Constraining Factor and correlation to AIL Peak Load
Central Alberta		
6 – 240 kV circuits between Edmonton and Calgary	Voltage	Heavy summer load and no import.
6 – 240 kV circuits between Edmonton and Calgary	Thermal capacity	High load in summer with no import, and lighter loads as exports increase.
6 – 240 kV circuits between Edmonton and Calgary	Stability	Light load coupled with heavy export (independent of season).
Northern Alberta		
7L62/7L58/7L82	Voltage and thermal capacity	TMR is currently used to alleviate voltage violations and thermal capacity constraints. NW peak load is generally coincident to AIL peak load, and peak loading occurs in winter.
Grand Prairie NW-9	Voltage	Winter peak load, which is generally coincident to AIL peak load.
NE Area (Fort MacMurray)	Voltage and stability, OPP limits area imports and exports	Peak load conditions generally driven by generation, or generator outage. These factors are not correlated to time of AIL peak load.
NE Path from Edmonton to Ft Sask	Voltage and thermal capacity	Voltage and thermal capacity constraints occur during contingencies. Thermal capacity constraints occur in summer.

Based on the interviews with transmission planners, transmission upgrades in southern Alberta are driven by constraints that occur in summer, and therefore do not coincide with the time of annual AIL peak load.

Transmission upgrades in northern Alberta are driven by constraints that occur during peak load conditions in winter, which generally coincide with

the time of AIL peak load, or constraints are driven by generation, which does not coincide with the time of AIL peak load.

This qualitative assessment shows that transmission planning is very complex and is not dominated by any one simple factor such as AIL peak load. Transmission planning is driven by a large number of independent factors such as the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta.

2.2.3. Coincidence between Bulk System Load and AIL Load

In addition to the qualitative assessments in Section 2.2.2, quantitative analysis was undertaken to study the correlation between the time of maximum stress on the Bulk System and the time of AIL peak load. This exercise must be simplified because maximum stress can occur for a number of different reasons. One way to simplify the issue for study is to simply consider loading on Bulk System components. While this may provide some insight, it does not fully reflect how the system is planned, because the system is planned with computer simulations that consider interaction between components. This study was accomplished by obtaining meter data for 240 kV circuits that were in service during 2003, when the original cost data for the TCCS was obtained. For this analysis, the 240 kV circuits are assumed to represent the Bulk System.

Meter data was obtained for each 240 kV circuit, by hour, for 2004 and 2005. The AIL load by hour was also obtained by hour over the same period. Since all meter data is actual data, this analysis has some shortcomings. For example, transmission planning is done on the basis of no opportunity sales, whereas actual meter data does include any opportunity sales that occurred. The meter data includes actual imports and exports. No provision is made to adjust meter data for abnormal conditions such as transmission contingencies or generator outages. The lack of correction for these

conditions is not expected to influence the conclusions. The impact of some of these conditions is discussed below.

The actual meter data for 2005 includes exports of 1,038 GWh that accounts for approximately 1.5% of the total load. It is impractical to assess which generator would be dispatched down in order to calculate the load flow on all circuits under the no export scenario. Such analysis would be required for each hour during which export occurred, if correlations were calculated without exports. The total amount of export is small in comparison to the Alberta load (1.5%) and therefore would have minimal impact on the circuit loading data.

Transmission planners have in the past excluded exports when developing transmission expansion plans. The Transmission Regulation A.R. 174/2004 that came into effect in 2004 requires that the AESO make arrangements for the expansion of the transmission system so that Alberta can import and export electricity on a continuous basis, at or near the transmission facilities path rating. Therefore, it is appropriate to include exports and imports in the analysis of factors that cause stress on the Bulk System in Alberta as was done in the analysis of correlation between AIL and circuit loading.

There was one major transmission contingency in 2005 that occurred when a tornado damaged transmission lines and customers facilities in the Empress area and service was restored in less than 2 weeks.

The hourly load data for each circuit was analysed with respect to the AIL load to determine the correlation between the two. The hourly load for each circuit, and the hourly AIL was analysed to determine the Pearson correlation coefficient. The Pearson correlation coefficient is a dimensionless index that ranges from -1.0 to $+1.0$ inclusive and reflects the extent of a linear relationship between two data sets. More information on the Pearson Coefficient can be found on the internet by Eric W. Weisstein. "Correlation

Coefficient." From [MathWorld](http://mathworld.wolfram.com/CorrelationCoefficient.html)— A Wolfram Web Resource at the following link: <http://mathworld.wolfram.com/CorrelationCoefficient.html>

A coefficient of -1.0 indicates an inversely proportional perfectly linear relationship between the two data sets, while a coefficient of $+1.0$ indicates a directly proportional perfectly linear relationship, as shown in the following examples.

Figure 2 Pearson Coefficient of -1 (Inversely Proportional Linear Relationship)

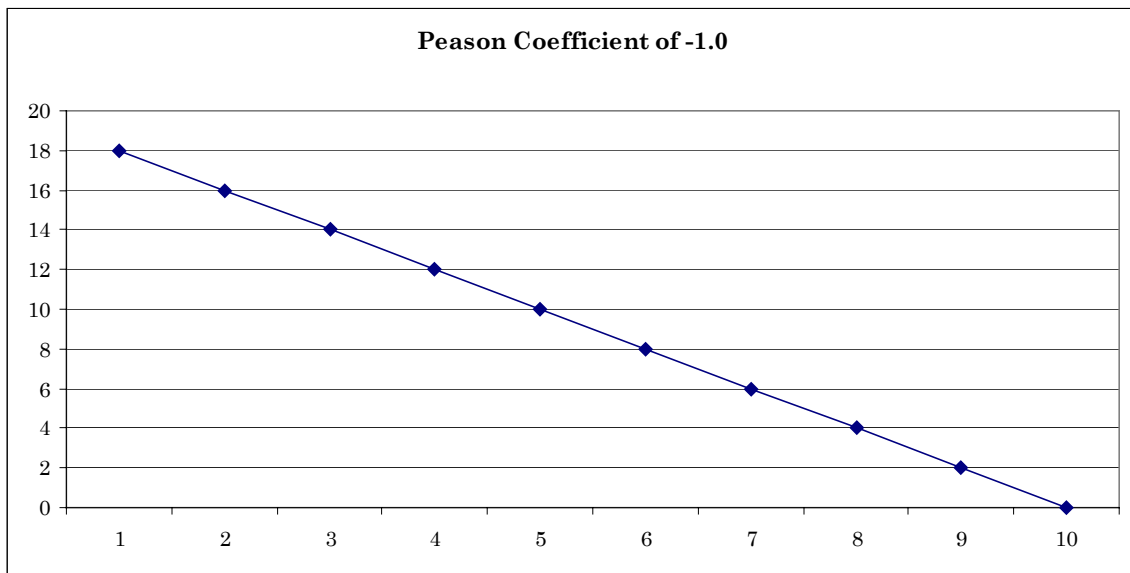
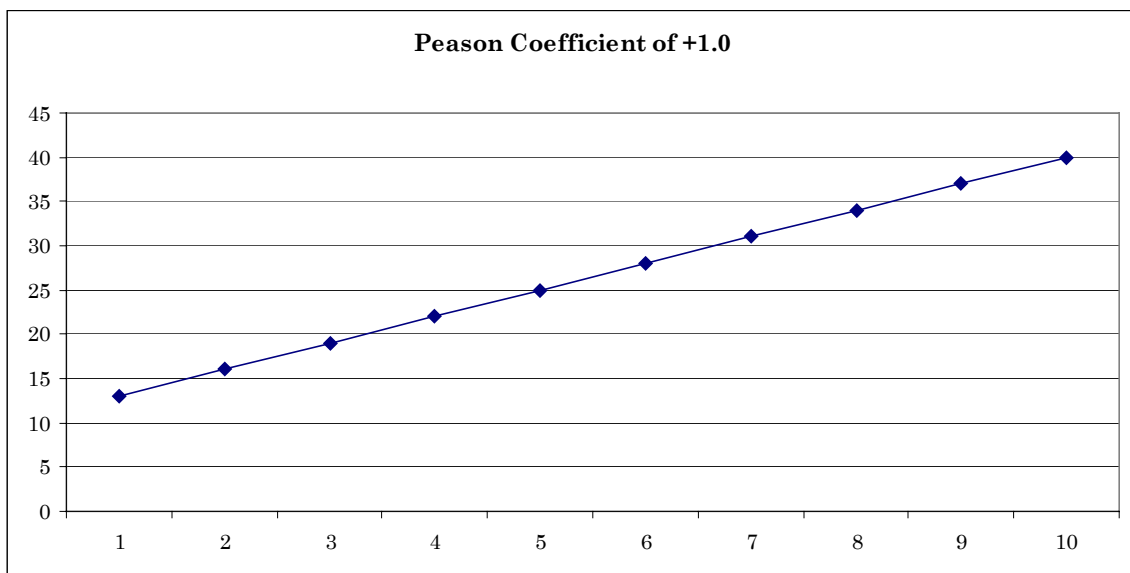
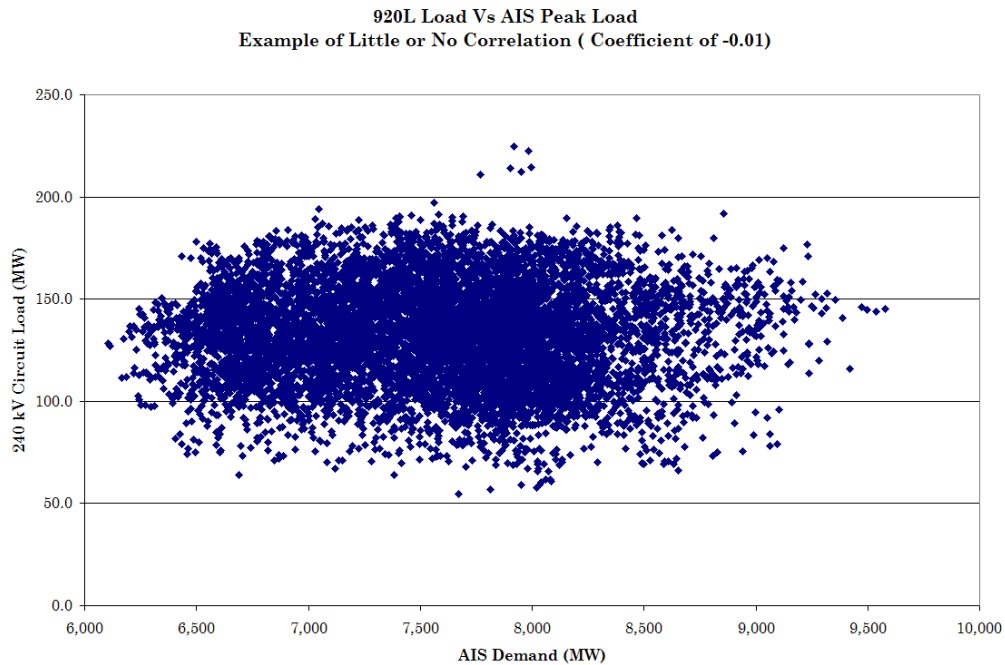


Figure 3 Pearson Coefficient of $+1$ (Directly Proportional Linear Relationship)



A Pearson coefficient of 0 indicates that there is no correlation between the two datasets. The following example is of 920L, a 240 kV circuit from Edmonton to Fort Saskatchewan, which has a Pearson coefficient of closest to zero. The Pearson coefficient for 920L is -0.01 .

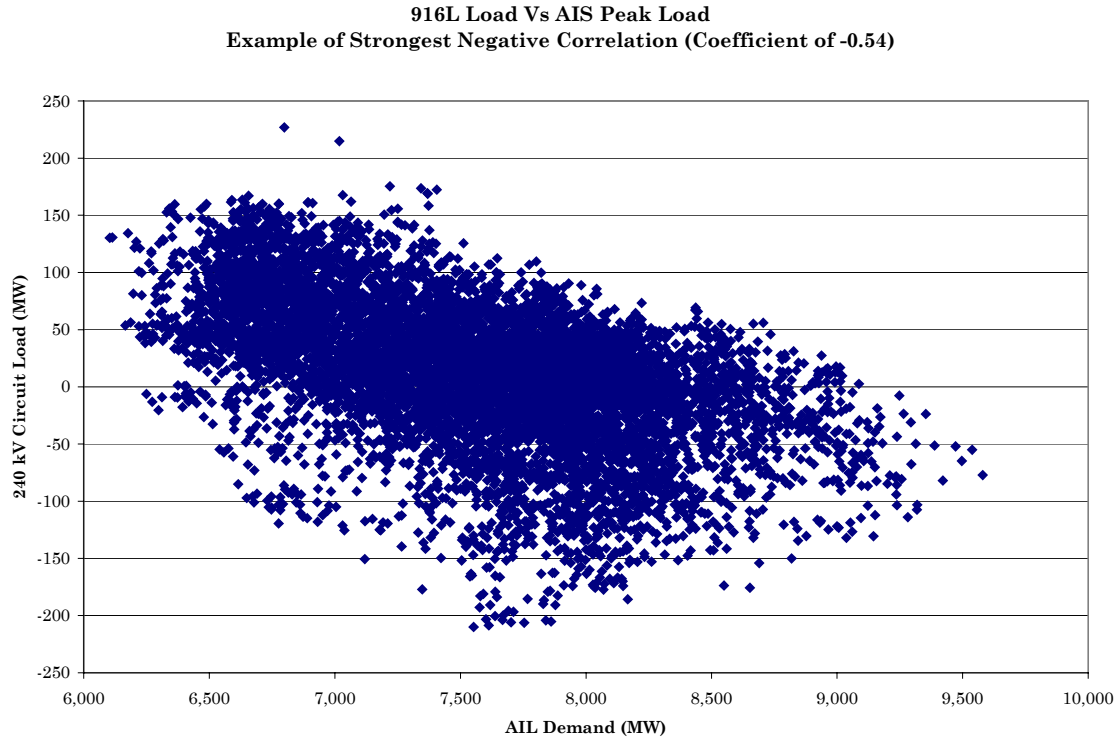
Figure 4 Pearson Coefficient of Near 0 (Independent Variables)



Meter data, by hour for 2004 and 2005 was obtained for 240 kV circuits. The circuit load and AIL was analyzed to determine a correlation coefficient between the two. A total of eighty 240 kV circuits were studied for line loading correlation to AIL load which represents 85% of the Bulk System lines on the basis of NBV. The 240 kV circuits included 57 AltaLink circuits and 22 Atco Electric circuits. In total, 45 of 79 in 2004 and 51 of 79 in 2005 exhibited correlation coefficients of greater than zero indicating that line loading generally increases as AIL load increases. The remaining circuits exhibited negative correlation coefficients, which indicates that circuit loading generally decreases as AIL load increases.

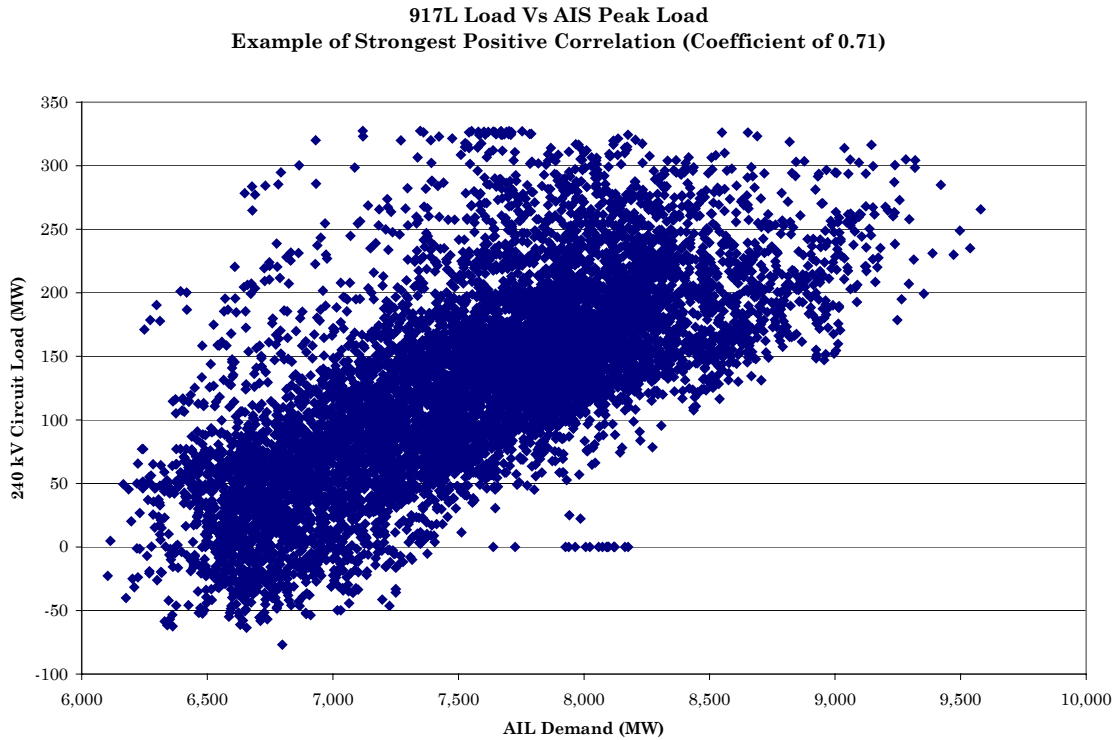
The circuit with the strongest positive correlation coefficient was 917L with a correlation coefficient of 0.71 and the circuit with the strongest negative correlation coefficient was 916L, both of which are located in Calgary and has a correlation coefficient of -0.54 as shown below.

Figure 5 240 kV Circuit with Strongest Negative Correlation.



The 240 kV circuit with the strongest positive correlation between line loading and AIS was 917L with a correlation coefficient of 0.71 as shown in the following figure.

Figure 6 240 kV Circuit with Strongest Positive Correlation Coefficient



Correlation between AIL Load and 240 kV Circuit Load in Alberta

There is no strong correlation between peak AIL load and peak 240 kV circuit load in Alberta. The Atco Electric circuits more frequently exhibited a positive correlation between AIL load and circuit load than the AltaLink circuits in southern Alberta. 64% and 73% of the Atco Electric circuits had a positive correlation coefficient between AIL load and circuit load in 2004 and 2005 respectively. 54% and 61% of the AltaLink circuits had a positive correlation between AIL load and circuit load in 2004 and 2005 respectively. 57% and 65% of 240 kV circuits in Alberta had positive correlation between AIL load and circuit load in 2004 and 2005 respectively. This reinforces the planners view that in the north west part of the province, the Bulk System stress occurs at the same time as the peak load in the area, all of which occurs coincident to the annual peak AIL. The following table show the

overall correlation between AIL load and circuit load weighted by various factors for 240 kV circuits in Alberta.

Table 2 Correlation Coefficients between Line Load and AIL Load

Pearson Correlation Coefficient	2004	2005
Line Loading weighted by number of lines	0.07	0.12
Line Loading weighted by circuit length	0.01	0.08
Line Loading weighted by NBV	0.11	0.18

The following table shows the correlation between AIL load and circuit load as a percent of thermal capacity. Circuit load as percent of thermal capacity increases in the summer as a result of lower thermal capacity in the summer, and correlation coefficients are somewhat lower.

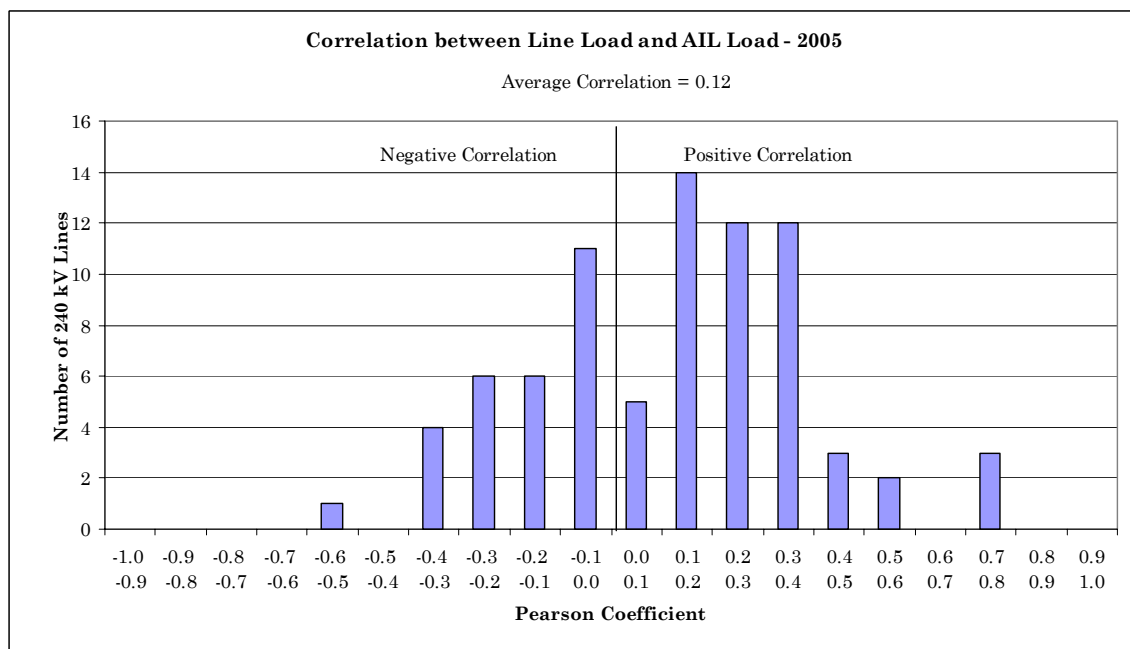
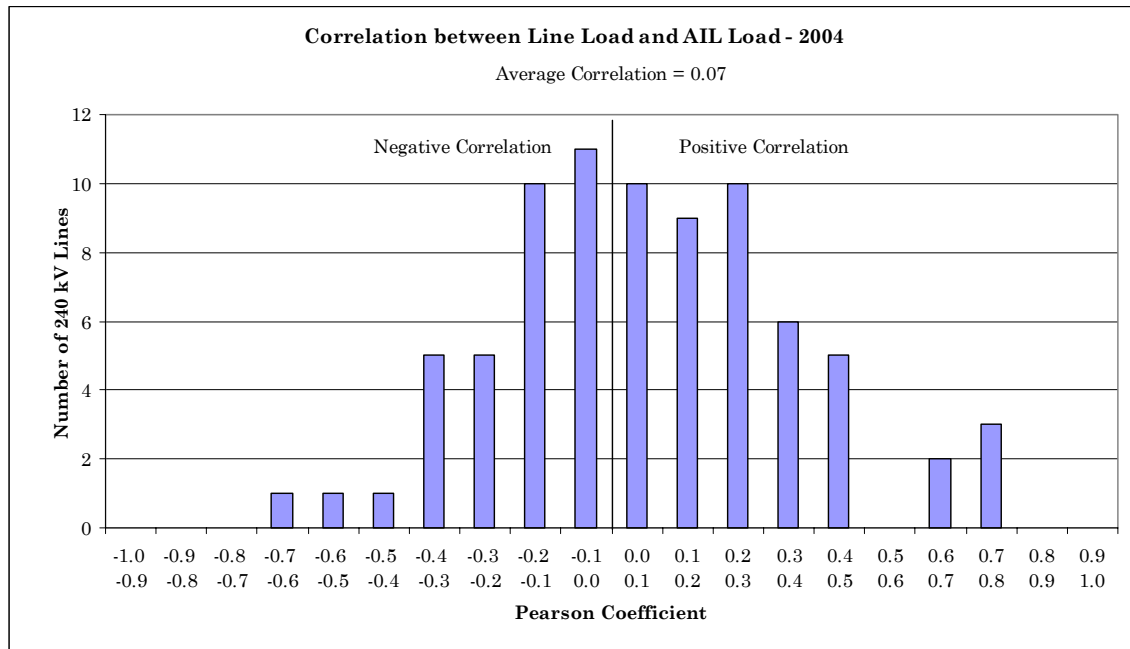
Table 3 Correlation Coefficient - Load as % of Thermal Capacity and AIL Load

Pearson Correlation Coefficient	2004	2005
% of Thermal Capacity weighted by number of lines	0.00	0.00
% of Thermal Capacity weighted by circuit length	-0.04	-0.03
% of Thermal Capacity weighted by NBV	0.04	0.04

The distribution of correlation coefficients are shown in the following series of charts.

These two charts show the correlation coefficients between AIL load and circuit load by the number of 240 kV circuits.

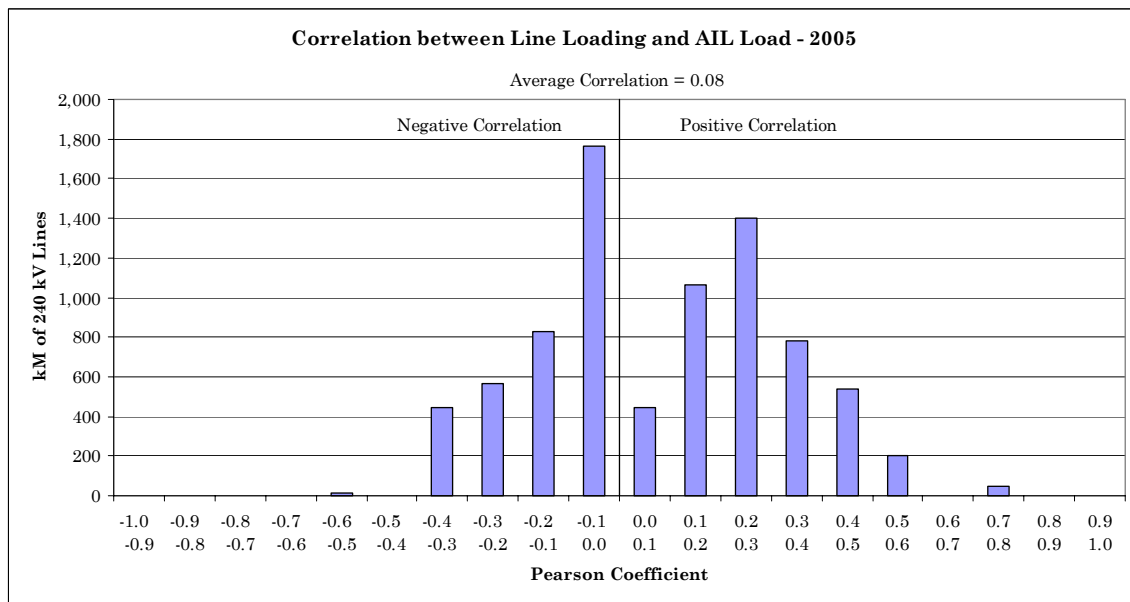
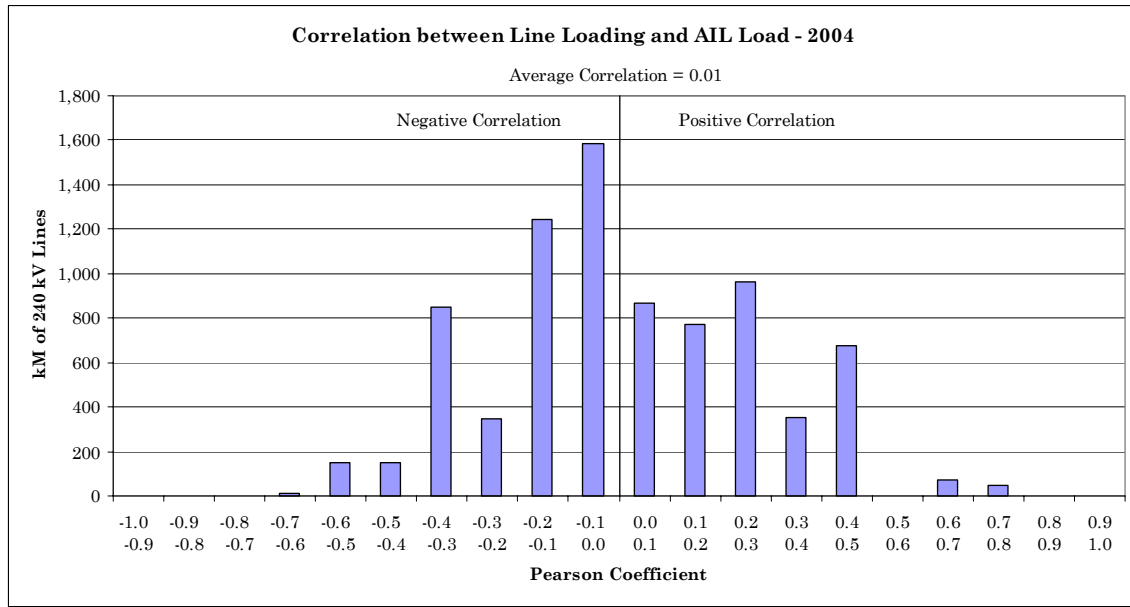
Figure 7 Occurrence of Correlation Factors by Number of 240 kV Circuits



Using the number of lines as an indicator of correlation has some drawbacks because all lines are considered equal regardless of their length or value. The

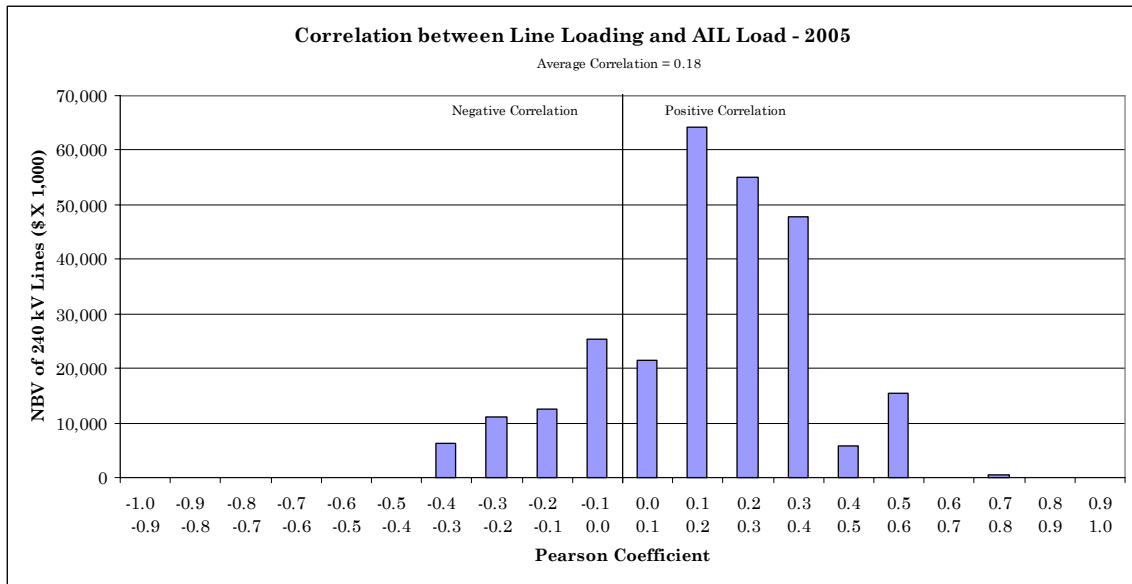
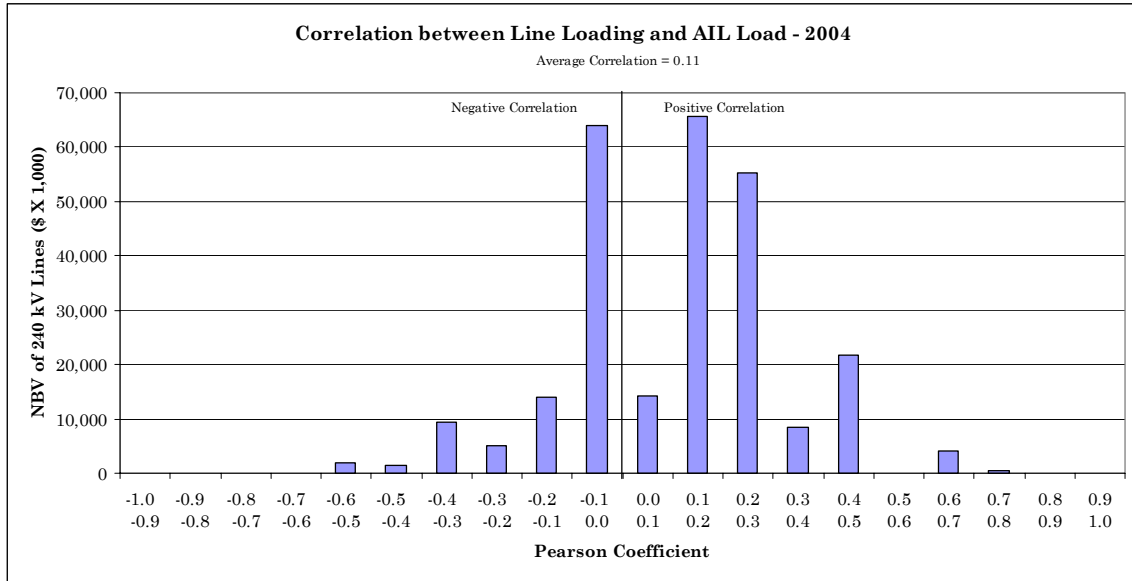
same correlation analysis was weighted by line length to provide the following distribution. The large number of kM of line with a slightly negative correlation includes lines within the Edmonton to Calgary corridor.

Figure 8 Occurrence of Correlation Factors weighted by Line Length



Net Book Value of the 240 kV circuits was also used to weight the correlation coefficients as shown in the following charts.

Figure 9 Occurrence of Correlation Factors weighted by Net Book Value



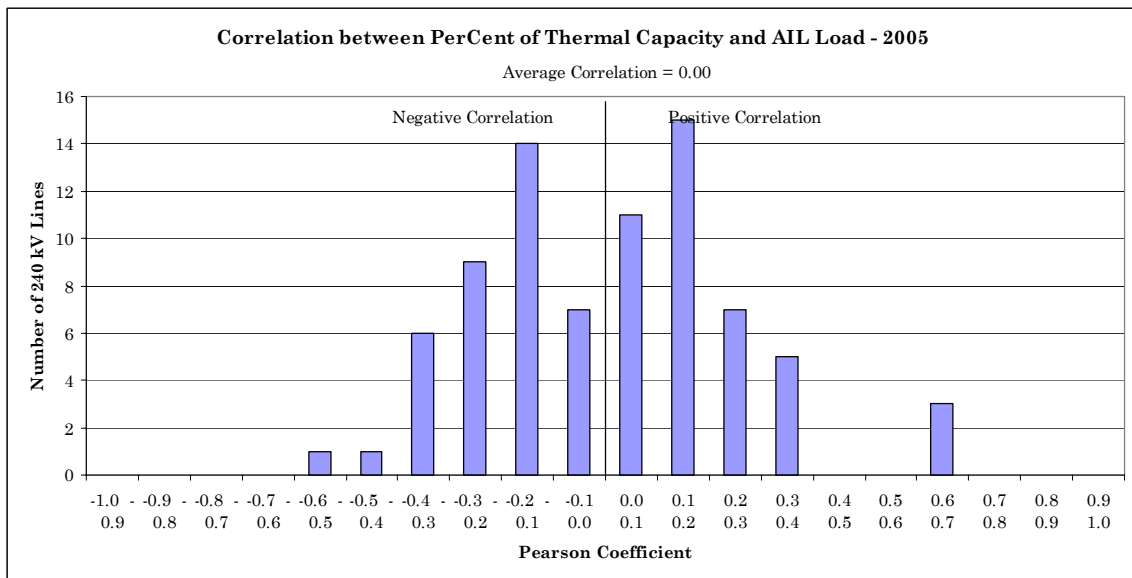
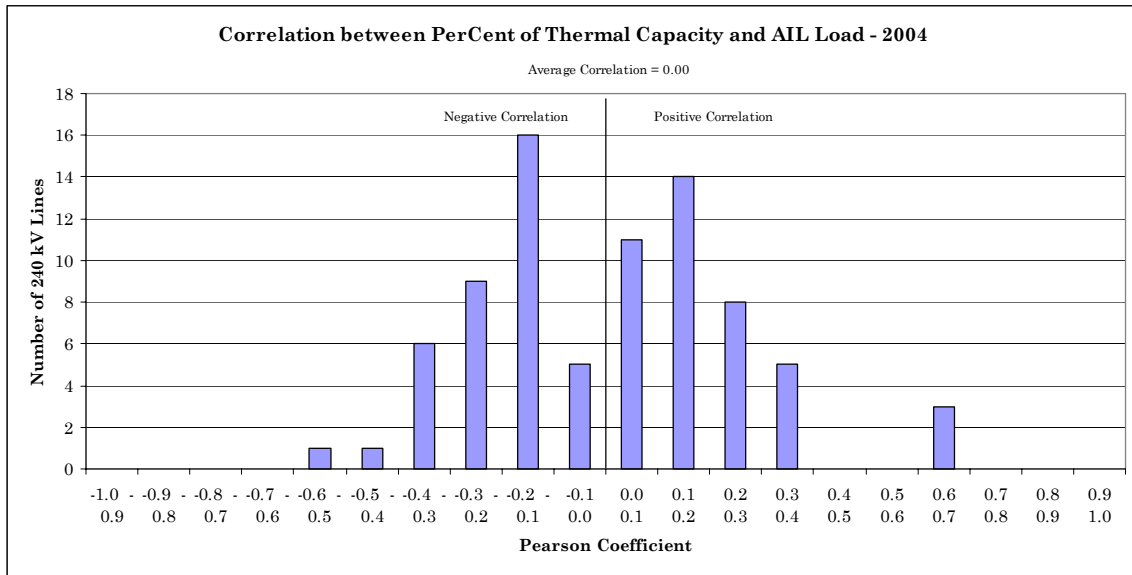
Weighting by NBV provides heavier weighting to new lines.

Weighting by NBV relates closest to the revenue requirement, while weighting by line length may relate better to cost causation in the long term.

2.2.4. Percent Loading based on Thermal Capacity

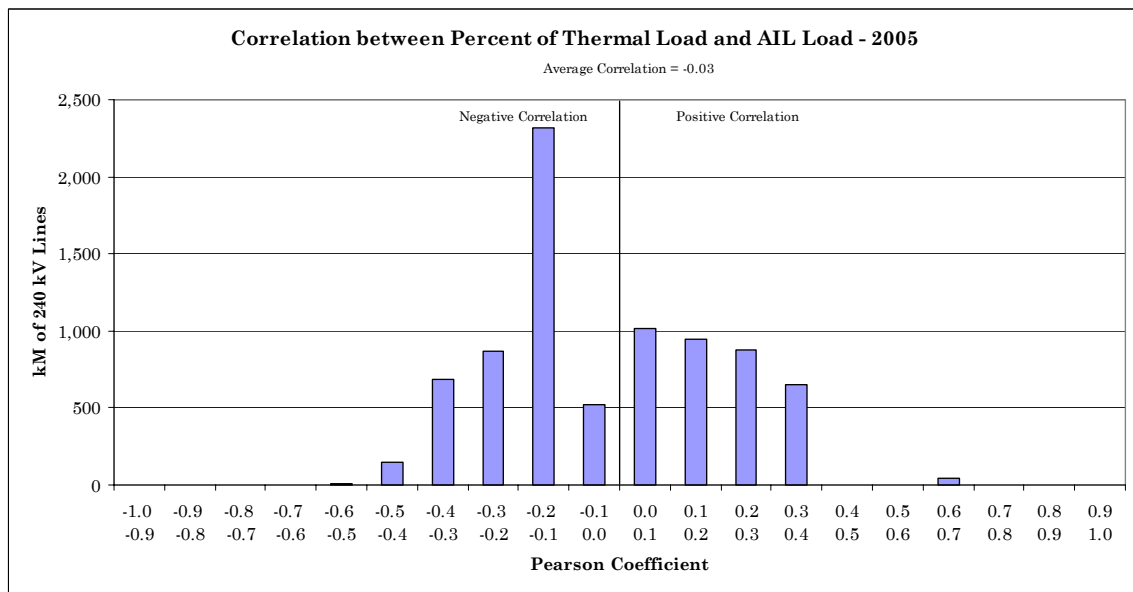
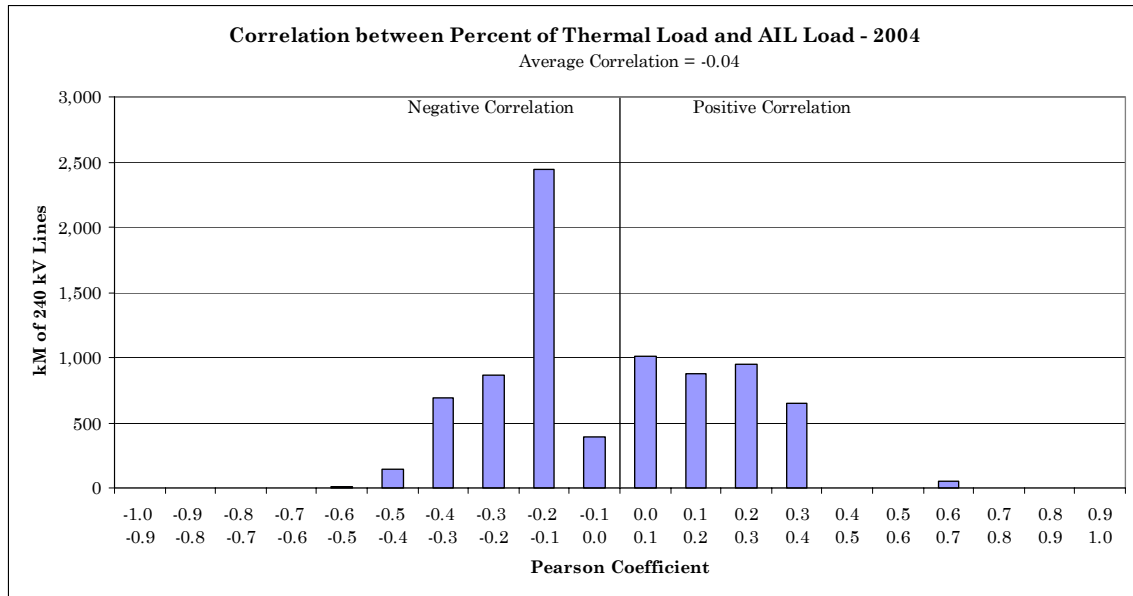
Correlation factors were also calculated on the basis of circuit load divided by thermal capacity. Since the summer thermal capacity is equal to or less than the winter capacity, and the AIL peaks in the winter, the correlation factors for thermal capacity will be lower than those of simple line loading.

Figure 10 Occurrence of Correlation Factors by Number of Circuits



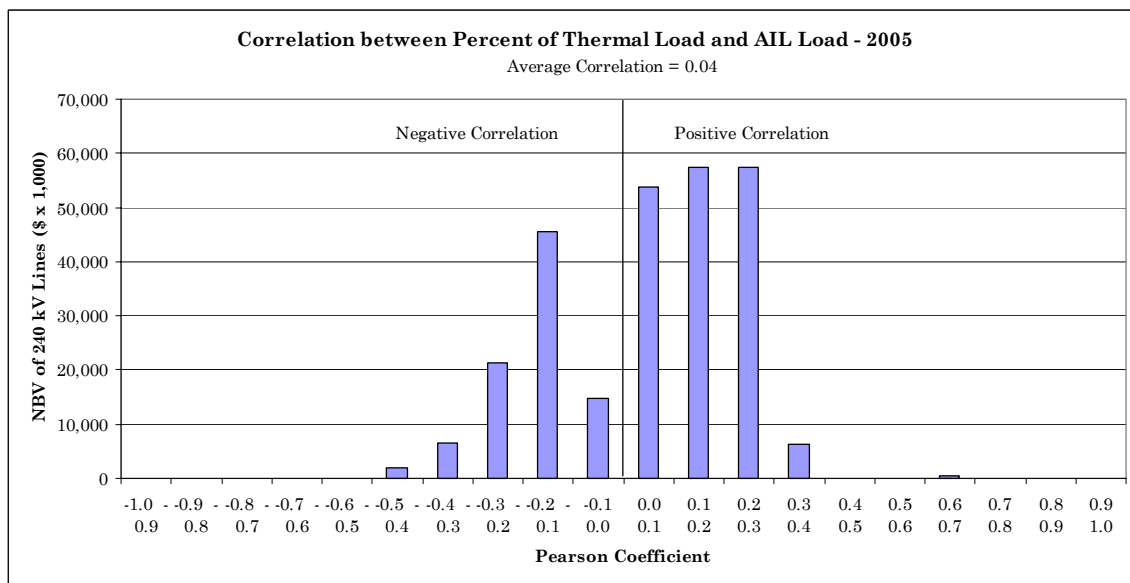
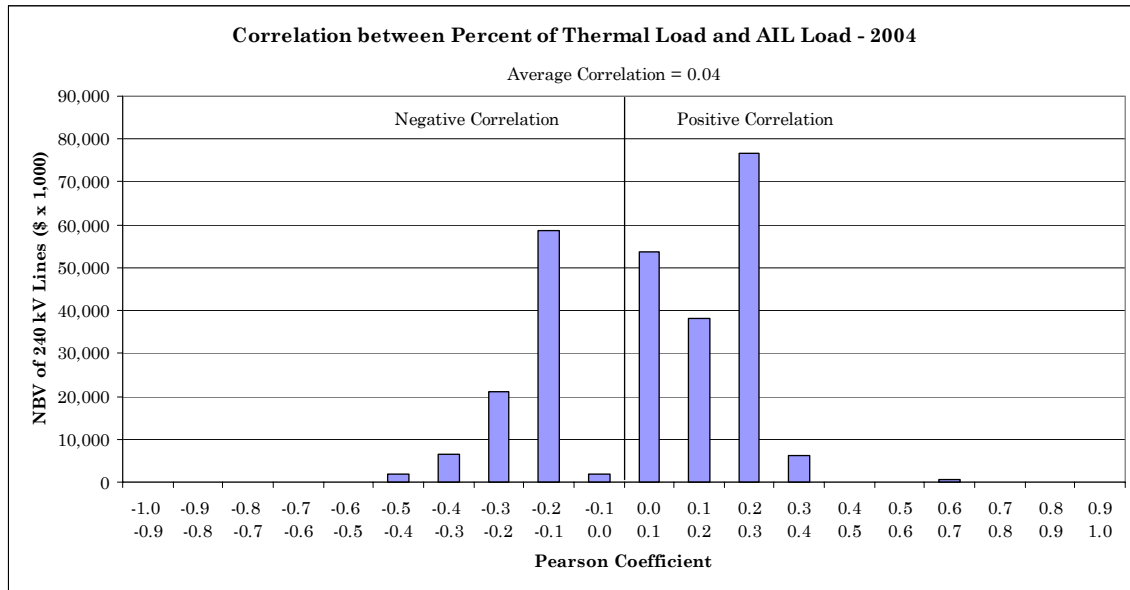
Again, using the number of lines as an indicator of correlation has some drawbacks because all lines are considered equal regardless of their length or value. The following analysis was weighted by line length.

Figure 11 Occurrence of Correlation Factors Weighted by Line Length



The following charts show the correlation factors between AIL load and circuit load as % of thermal capacity, weighted by Net Book Value.

Figure 12 Occurrence of Correlation Factors Weighted by Net Book Value

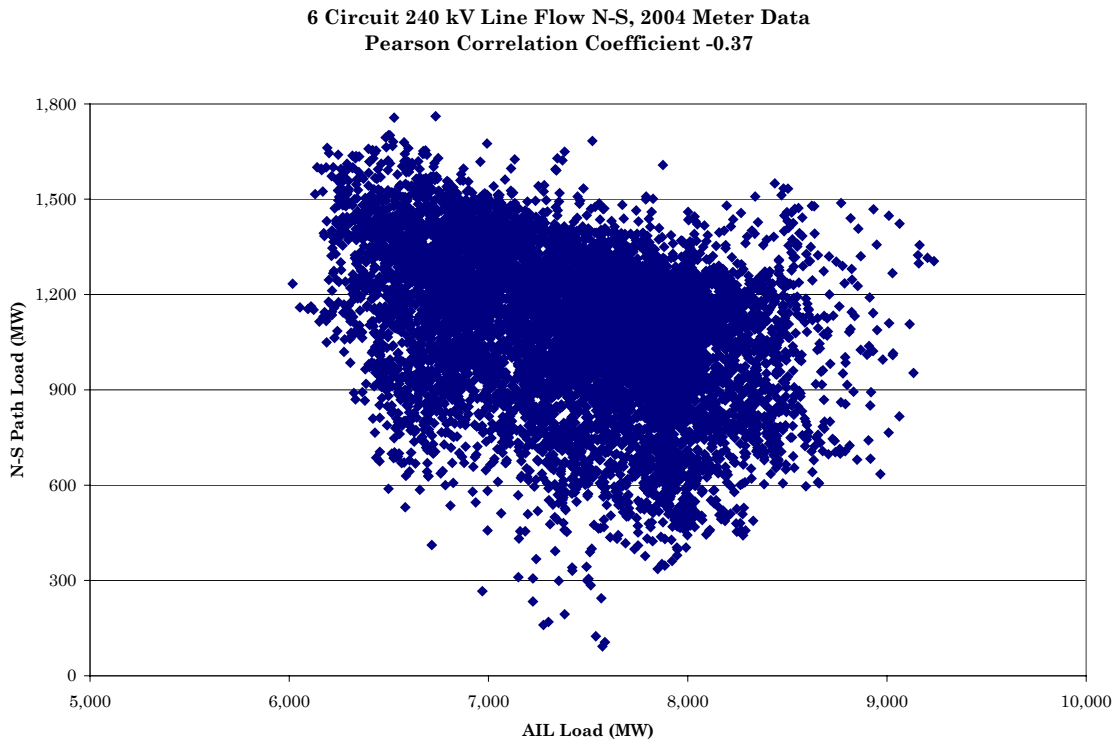


Flow on the North-South Path between Edmonton and Calgary

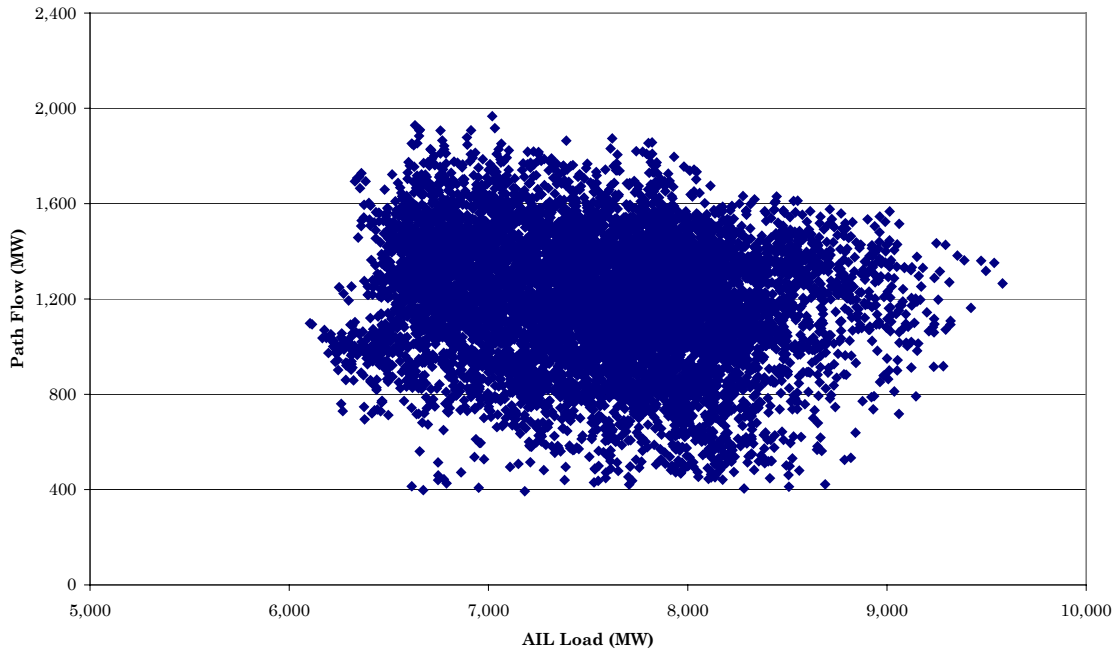
The path flow south of KEG (Keephills, Ellerslie and Genesee) was used as an example in the original TCCS to demonstrate that the Bulk System components are not always stressed at the time of the annual system peak load. For the path between Edmonton and Calgary, path flows exhibit an inverse correlation to the system peak load.

The actual flow on the south of KEG path is shown below, and the Pearson correlation coefficient between path flow and AIL load is negative 0.37 and negative 0.15 for 2004 and 2005 respectively. The actual flow south of KEG is measured as the sum of the loads on the six 240 kV circuits flowing south of KEG.

Figure 13 North-South Flow from Edmonton with Actual Meter Data

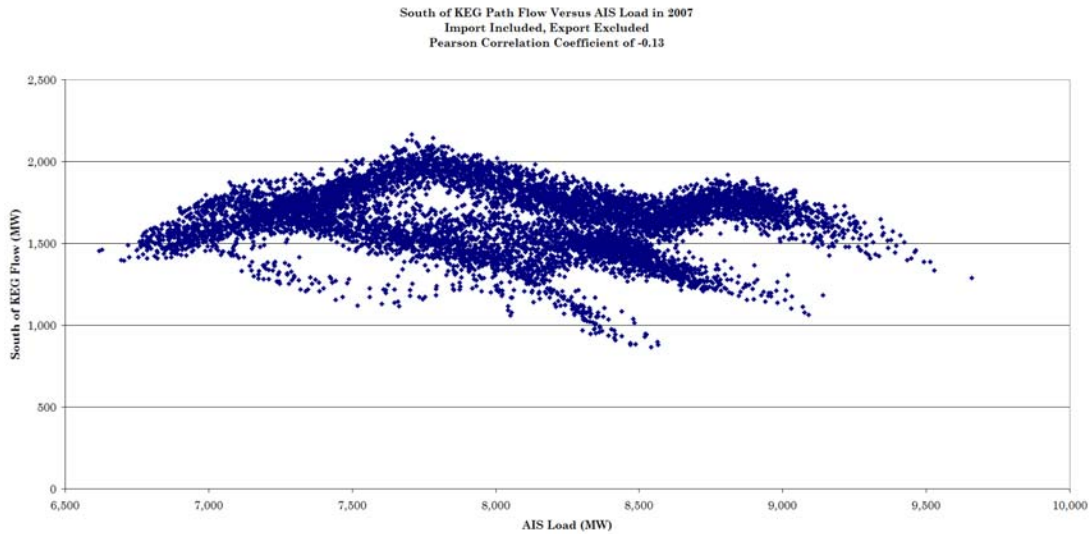


6 Circuit 240 kV Line Flow N-S, 2005 Meter Data
Pearson Correlation Coefficient -0.15



Detailed data for that path was also available on a forecast basis for 2007, as a result of its examination in the original TCCS. For the 2007 forecast data, exports were excluded to consider Alberta load only while imports were included in this scenario. The Pearson's coefficient for the south of KEG path based on 2007 forecast load was -0.13. This test suggests actual data provides conclusions similar to those that would be reached using forecast data for planning purposes.

Figure 14 The Path Flow South of KEG



Observations

The analysis finds the relationship between AIL peak load and circuit load, weighted by a number of factors, is weak or non-existent. The analysis was completed on the basis that circuit loading and relates to maximum stress on the Bulk System. Some components of the Bulk System such as the north-south lines between Edmonton and Calgary exhibit a negative correlation where the circuit loads are highest at the time that AIL is low.

In reviewing the hourly data, none of the 240 kV circuits experienced its annual peak load during the hour of the AIL peak load. Also, none of the 240 kV circuits experienced its monthly peak load during the hour of the monthly AIL peak load.

During the hour of AIL peak load, 240 kV circuits were loaded at about 60% of their annual peak load on average. During the hour of AIL peak load, 5 of 79 lines in 2004 and 4 of 79 lines in 2005 were at 90% or more of their annual peak load.

This analysis was completed to find the correlation between the AIL peak load, and maximum stress on the system (using line loading, and percent of

thermal capacity as proxy for maximum stress). On the basis of this analysis, the correlation between coincident peak load and stress on the Bulk System is weak and is negative for the Bulk system.

Neither the quantitative analysis of correlation between maximum stress and AIL, nor the qualitative review of stressors for the bulk system identify AIL coincident peak as a significant factor in the expansion of the transmission system.

2.3 Threshold of Significant Correlation

During the Stakeholder sessions, stakeholders asked what correlation coefficient might be considered significant. No threshold was established to determine whether the correlation is significant or not.

Pearson's Correlation Coefficient can take on the values from -1.0 to 1.0 where -1.0 is a perfect negative (inverse) correlation, 0.0 is no correlation, and 1.0 is a perfect positive correlation

A threshold to determine whether a correlation is significant would vary with a number of factors. If measurement of data is completed quantitatively, then a higher correlation factor is needed before the relationship is considered significant. If measurement of data occurs qualitatively in the form of an opinion, then a lower correlation factor may be deemed significant. In the case of the TCCU, the data is all metered (both AIL and circuit load). Since the basic data is metered, a relatively high correlation factor would be required in order to confirm a strong relationship between AIL and circuit load.

If the correlation factor between AIL and circuit load, and between AIL and thermal stress were close to 1.0, then one may conclude that AIL load is strongly related to Bulk System stress, and that demand related Bulk System costs be classified on the basis of the coincident peak (CP). Since the

correlation factors were so low, there was no requirement to determine a threshold.

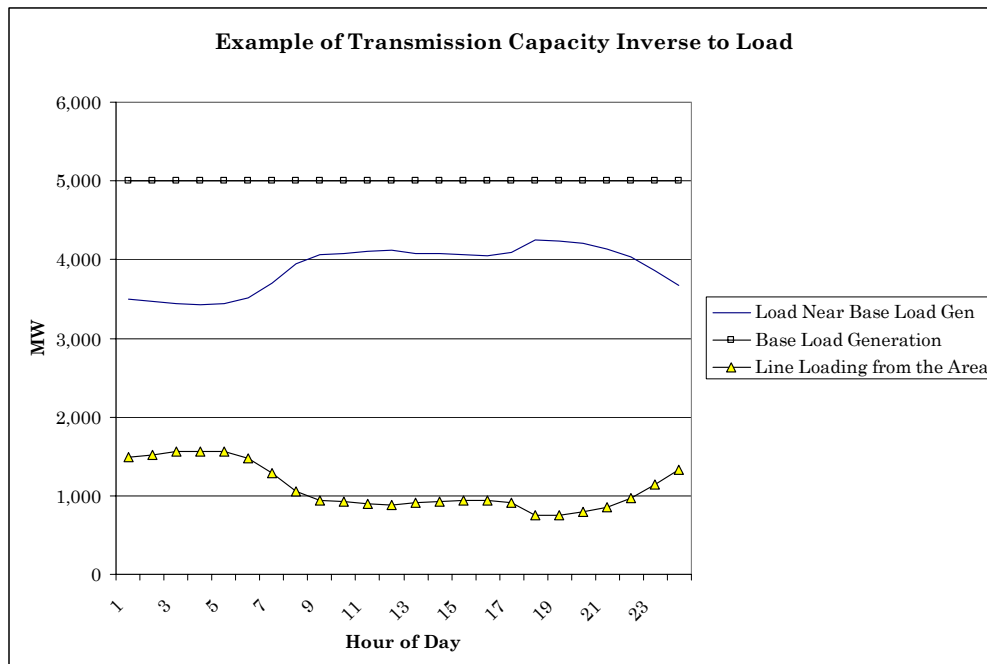
If a threshold to determine the strength of a relationship were required, one must also be cautious of causality. A correlation between two data sets may be observed even in the absence of a cause and effect relationship. In the absence of a cause and effect relationship, correlation factors would change over time.

The analysis of AIL versus circuit loading (both in MW and % of thermal capacity) was completed in order to test for correlation and determine whether or not a 1 CP is appropriate for the classification of demand related Bulk System costs. The correlation factors ranged from -0.04 to 0.18 depending on the weighting. These low correlation factors indicate that circuit loading (Bulk System stress) is not strongly correlated to AIL load and that 1 CP is not an appropriate means of classifying demand related Bulk System costs.

2.4 Summary – Classification of Bulk System

This report was completed to study the factors that drive demand related costs of the Bulk System. Interviews with transmission planners to determine the factors that lead to expansion of the Bulk System completed a qualitative analysis. The factors that cause planners to upgrade the Bulk System include violations of planning criteria (indicating stress on the Bulk System) with respect to thermal capacity, voltage and stability. The time of maximum stress on the Bulk System is driven by a number of variables including the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta.

The following example demonstrates the potential for a Bulk System to be lightly loaded at the time of system peak load, and to be stressed during light load hours. Consider an area where base load generation exceeds the load in the area. The difference must be moved out of the area with transmission lines. As shown, the maximum line loading out of the area occurs during the lightest load hours.



The correlation analysis was performed for the purpose of a high level test of the hypothesis that there is a correlation between the timing of need for Bulk System upgrades and the timing of system peak load. The result of the analysis is that there is very little, if any correlation between the maximum stress on the Bulk System and the AIL peak load. The maximum stress on the Bulk System is driven by a number of variables including the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta. As these variables change, the time at which maximum stress occurs on the Bulk System will also change.

2.4.1. Classification of Bulk System Costs

The original topic of discussion was the classification of Bulk System Costs. The Transmission Cost Causation Study identified that the majority of costs are classified as demand related costs but the demand type or timing was not fully studied because there is only one rate class.

The Transmission Cost Causation Study considered that coincident load at the time of maximum stress on the Bulk System is the appropriate benchmark for the classification of bulk system costs, but noted that coincident load at the time of maximum stress is not a practical demand related billing parameter.

Based on the assessments of planners and analysis earlier in this section, it is apparent that the time of maximum stress on the Bulk System occurs at various times throughout the year, and the time of maximum stress for one part of the Bulk System does not coincide with maximum stress for other parts of the system. Different areas of the Bulk System experience maximum stress at various times during the year and under different planning criteria. There is diversity among loads in Alberta, and there are factors beyond load (i.e., generation, imports, etc.) that cause maximum stress and drive the need to expand the Bulk transmission system.

Transmission expansions in southern Alberta have been driven by thermal capacity constraints in the summer, and in the future, transmission expansion in the south will be driven by the addition of wind generation. Some transmission expansions in northern Alberta are driven by load related concerns that occur in the winter and coincident to the peak Alberta load.

The TCCS identified that the Local System was designed to serve an area with a small number of points of delivery. By extension, the Bulk System is designed to serve a larger number of points of delivery. The Bulk System must be designed to meet the demand of a larger group of POD's.

The coincident peak of the AIL (all POD's in the province) encompasses too much diverse load over too large an area and is not a reliable or predictable factor in cost causation on the Bulk System. Transmission system planners do not plan bulk system components in response to system peak load, but in response to conditions in an area that result in a violation of thermal capacity, voltage or stability criteria in that area of the Bulk System. Allocation of costs to the coincident peak has the potential to shift loads away from the coincident peak without any corresponding reduction in the causation of costs resulting in a volatile cost allocation.

At the POD, the coincident load to maximum stress is the same as the maximum demand (ignoring seasonal changes in thermal capacity). 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. If there were no diversity, then maximum demand and coincident load to maximum stress would occur at the same time and both parameters would be appropriate to classify the demand related costs.

If maximum stress occurs at the time of the peak system load then coincident peak load and maximum demand are equal. If maximum stress occurs at a different time, then the planners model the system on the basis of an

estimate of load at the time of maximum stress, which is neither AIL coincident peak load, nor maximum demand.

Given that maximum demand is known and measured by POD and is easy to understand and is less volatile than load coincident to AIL peak system load, maximum demand is a better classification of demand related costs in the Alberta transmission system at this time.

The time of maximum stress on the Bulk System is driven by a number of variables including the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta. The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta. The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System. When there is a shift in location and production profiles for generation, or there is a shift in location and profiles of load, the classification of demand related costs should be reassessed to determine the most appropriate measure.

2.5 Contract Capacity

Stakeholders have asked if DTS contract capacity is a better measure of cost causation than peak demand at a POD. The System Access Service Agreement for Demand Transmission Service includes Article 3 that is titled Contract Capacity. The Agreement simply lists the Contract Capacity in MW and this value is commonly referred to as the DTS contract capacity. The Agreement is part of the AESO Terms and Conditions, and refers to the AESO Terms and Conditions for definitions.

The AESO Terms and Conditions define contract capacity as follows:

“Contract Capacity” means the peak demand or supply capability (expressed in MW), as set out in the System Access Service Agreement.

The AESO Terms and Conditions define the provision of service as follows:

3.1 Provision of Service

Subject to Article 17, the AESO agrees to provide System Access Service, up to and including the POD or POS, to all Customers who have executed a System Access Service Agreement and abide by this Tariff. The AESO is not obligated to provide service to a Customer in excess of 110% of the Contract Capacity set out in the Customer's System Access Service Agreement.

The AESO Terms and Conditions limits the provision of

17.1 Service Not Guaranteed

Although precautions are taken to guard against System Access Service interruptions, the AESO does not guarantee uninterrupted System Access Service.

The AESO plans to meet the forecast load growth in addition to the existing load. This planning does take into account load patterns and diversity between loads. If planning were based on DTS contract capacity, then contract capacities should reflect the diversity on the system, otherwise the system would be overbuilt.

The system load factor (AIL load) was approximately 80% and the average loading on 240 kV circuits during the peak hour was approximately 59% and 61% of each lines peak annual load for 2004 and 2005 respectively. These factors indicate the amount of diversity of load on the Bulk System.

The AESO cannot develop a long term transmission development plan on the basis of DTS contract capacity because actual contract capacities are generally not known out into the future. Experience shows that load growth occurs, but identifying future customers and their precise contract capacity is impractical. Therefore, load forecasts are used for transmission planning instead of DTS contract capacities.

While the AESO ensures that POD facilities are capable of supplying the maximum forecast load within the definition of the DTS contract capacity, the AESO does not plan the Bulk System to meet the sum of all DTS contract

capacities simultaneously. The AESO plans the Bulk System based on forecast load patterns and diversity between loads.

DTS contract capacity is not a good indicator of maximum stress on the Bulk System or Local System because it is one static value that does not reflect the forecast load over all hours of the year. The forecast load is a better indicator of stress on the Bulk System and therefore is a better indicator of cost causation.

2.6 Stakeholder Input

During the stakeholder input sessions, stakeholders raised a number of questions regarding aspects of this report. This section addresses these issues in a question and answer format.

Q: If two customers have equal maximum demands at the POD but different load factors, are both customers considered as equal in the planners' considerations?

A: Not necessarily. Transmission planners look for times and places on the transmission system when the system becomes stressed and violations of planning criteria occur. Transmission planners will set up system simulation models to simulate the system at the time that system stress occurs. The simulation models are based on load at the point in time that planners desire to study the system. Regarding the two customers in the question, the planners will forecast the load on each POD for the time of the system simulation. If both customers are expected to be at maximum load at that time, that is how the system is simulated. If one or both of the customers are expected to be operating at less than maximum load for the simulation period, then each of the POD's are modelled as they are expected to operate.

Q: Why is maximum demand at the POD a good indicator of use of the Bulk System?

A: The transmission system tends to be under stress when the POD's in the area are at or near their peak load. This is evident in southern Alberta where irrigation load occurs only in the summer, and the combination of all irrigation load stresses the transmission system (in the absence of stress caused by wind generation). The maximum demand at the POD's occurs in the summer while the AIL maximum load occurs in the winter. In this case, the maximum demand at the POD's causes stress to the Bulk System and requires expansion of the system, even though none of this occurs at the time of the peak AIL.

Q: Why not use energy for the classification of Bulk System costs?

A: The Bulk System is designed to meet the demand at the time of maximum stress. While the time of maximum stress may occur at times that are not immediately intuitive, planners do consider the loads and generation on line at the time that maximum stress is anticipated. The planners will develop an expansion plan that ensures that the transmission system can meet the forecast demand.

The original TCCS classified Bulk System costs as 81.5% demand related and 18.5% energy related and this analysis has not changed.

Q: Is demand billing over peak hours a better or worse alternative than CP or maximum demand billing?

A: Demand billing over peak hours is a rate design issue and both the TCCS and TCCU deal with solely with cost causation. This question is answered on the basis of cost causation for the purpose of a cost of service study.

Classifying demand related costs on the basis of demand during peak periods is one way of addressing the shortcoming of classifying costs on the basis of demand at the time of system peak. The interview with transmission planners indicates that planners must consider more hours than just the one-hour that constitutes the hour of the annual peak load in Alberta. Some

stakeholders believe that there are a small number of peak load hours that cause maximum stress on the transmission system, and therefore classification of demand related costs should occur on the basis of the average demand over peak load hours. Transmission planners have not identified any time frame or window during which all maximum stress situations could be encompassed. The transmission system in the south is stressed during the summer when many of the local POD's incur their maximum annual load, but this does not coincide with the provincial annual peak load, which occurs in the winter. The transmission system between Calgary and Edmonton is stressed during light load hours when base load generation production is not used locally, and is forced south to the Calgary area. These examples show that there is no well defined period during which maximum stress can occur, and therefore, demand related costs have not been classified on the basis of demand over some window of peak hours.

Q: Have you analysed the correlation between maximum demand at a POD and the coincident load to maximum stress?

A: No, there is no simple way to analyse a correlation between maximum demand at POD's and the time of maximum stress because each POD will peak at a different time. With the AIL, there is only one annual peak load hour, and there is chronological meter data which can be compared to circuit loading data and therefore correlation coefficients can be determined.

It is impractical to correlate maximum load at each POD with maximum circuit loading for each circuit due to the volume of POD's and circuits. Further, the correlations would somehow require weighting so that circuits near each POD would be given heavier weightings than remote circuits.

Q: Should only AltaLink and Atco Electric data be used for the study, since ENMAX and EPCOR do not have the same level of detail?

A: The TCCS study was completed on the basis of a cost causation study across the province of Alberta. The study was based on average cost across the province without considering costs by any geographic or service area. This approach is consistent with legislation that requires that rates for system access service be the same regardless of their location on the transmission system. Therefore, the transmission cost data from ENMAX and EPCOR were included.

The TCCS is a cost study that provides an overview of costs, but is not intended to be the sole basis for rate design. Rate design criteria typically take into consideration factors in addition to a cost study. Rate design should take into account unique customers or circumstances that cannot be addressed in a cost study.

3. INTERPROVINCIAL TIES

The interprovincial interconnections were built under the vertically integrated electric utility industry. The interprovincial ties were built on the basis of generation reserve sharing. With the construction of the tie line, Alberta and BC could rely on each other, thereby reducing the amount of generation reserve required to provide reliable electric service.

The Alberta BC Interconnection was commissioned in 1986, and was justified on the basis that the tie line was the equivalent of building 300 MW of peaking generation in Alberta to provide reliable service. The BC tie is a 500 kV AC tie line which has a thermal capacity in excess of 1,000 MW. The available transfer capacity is normally limited by voltage in southern Alberta. The export limit for the first five months of 2006 has typically been between 0 MW and 700 MW and has average 50 MW. The import limit for the same time period has typically been between 0 MW and 700 MW and has averaged 625 MW.

The Alberta Saskatchewan Interconnection was built in the late 1980's and is an asynchronous back-to-back DC link. The thermal capacity of the interconnection is 150 MW. Voltage limits and thermal capacity constrain the available transfer capacity of this interconnection. The export limit for the first five months of 2006 has ranged from 0 to 60 MW with an average of 30 MW. The import limit has ranged from 0 to 153 MW with an average of 150 MW.

While the interprovincial interconnections were built to provide "generation reserves" in a vertically integrated utility structure, since deregulation of the utility industry the interconnections have been used primarily for economic transactions on an opportunity basis (although a non-opportunity export rate is being proposed in the AESO's 2007 tariff application).

3.1 NBV of Interprovincial Interconnections

The net book value of the provincial interconnections is based on the value of the Langdon Substation and the 500 kV transmission line from Langdon to BC for the BC interconnection, and the transmission line from Empress to Saskatchewan (138 kV 830L), the McNeil converter station, and the Sask Border Tie for the Saskatchewan interconnection.

The NBV of these facilities is \$115 million (2003) and transmission NBV for the four largest TFO's was \$1,456 million. The TCCS identified that 46.1% (with compensation for CIAC) of the total NBV was associated with Bulk System facilities. Therefore, the Bulk System including interprovincial ties had a NBV of \$672 million.

The interprovincial ties comprise of 17% of the NBV of the Bulk System.

3.2 Summary

The TCCS determined there were three functions of a transmission system, and that interprovincial interconnections fall within the function of the Bulk System.

The Bulk System was defined as the system that delivers bulk electric energy (large volume) over a long distance to a number of users and this definition best describes interprovincial interconnections in the old and existing industry structures.

The cost of the interprovincial ties should continue to be part of the Bulk System pending a review of a rate or rate class for long term firm imports/exports.

4. LOCAL SYSTEM

The TCCS defined the Local System as follows: The Local System delivers electric energy from the Bulk System to a local area a small number of points of delivery. The Local transmission System is commonly understood to be the underlying transmission system that provides service to local points of delivery. The Local System is normally designed with two or more transmission circuits to each point of delivery or radial connection, such that continuous service can be provided in the event of an outage on one of the circuits. The Local System does not include radial transmission lines. An example of transmission facilities included in the Local System is the 138 kV lines within the City of Calgary.

With this definition, the Local System should include part of substation, which is served by multiple transmission lines (“networked”). The part of the networked substation included in the Local System would be the switches, circuit breakers and bus work on the high voltage side of the transformers. The original TCCS defined the Point of Delivery (POD) as follows: The point of delivery includes all facilities that provide service at one point of delivery substation, including a radial transmission line used exclusively by the point of delivery substation. The point of delivery facilities normally provides service to one customer (a distribution utility, or a transmission connected industrial customer).

The purpose of the distinction between local system and point of delivery was to allow the study of cost causation for facilities sized to meet the needs of an individual customer at the POD versus the cost causation for facilities sized to meet the needs of several customers.

The original TCCS study did not include the distinction of networked substation high-side facilities, because the TFO cost data did not provide enough detail to separate the cost of these facilities.

In order to study the relationship between the Local and POD costs within a networked substation, more detailed cost information is required. The 2003 cost data does not provide sufficient information to separate substation costs into Local System and POD related costs. However, 34% of POD's are radially fed while 66% of the POD's have more than one source line and would be networked. The impact of this distinction on the Local System and POD is therefore reduced.

Figure 15 Local System Components of a Single Transformer Substation

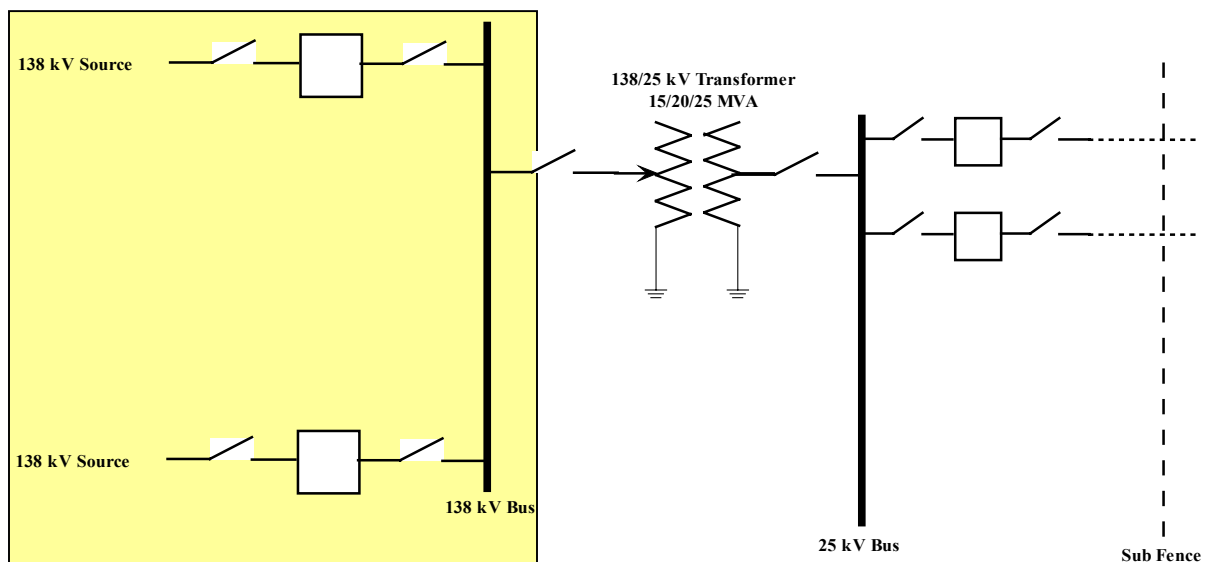
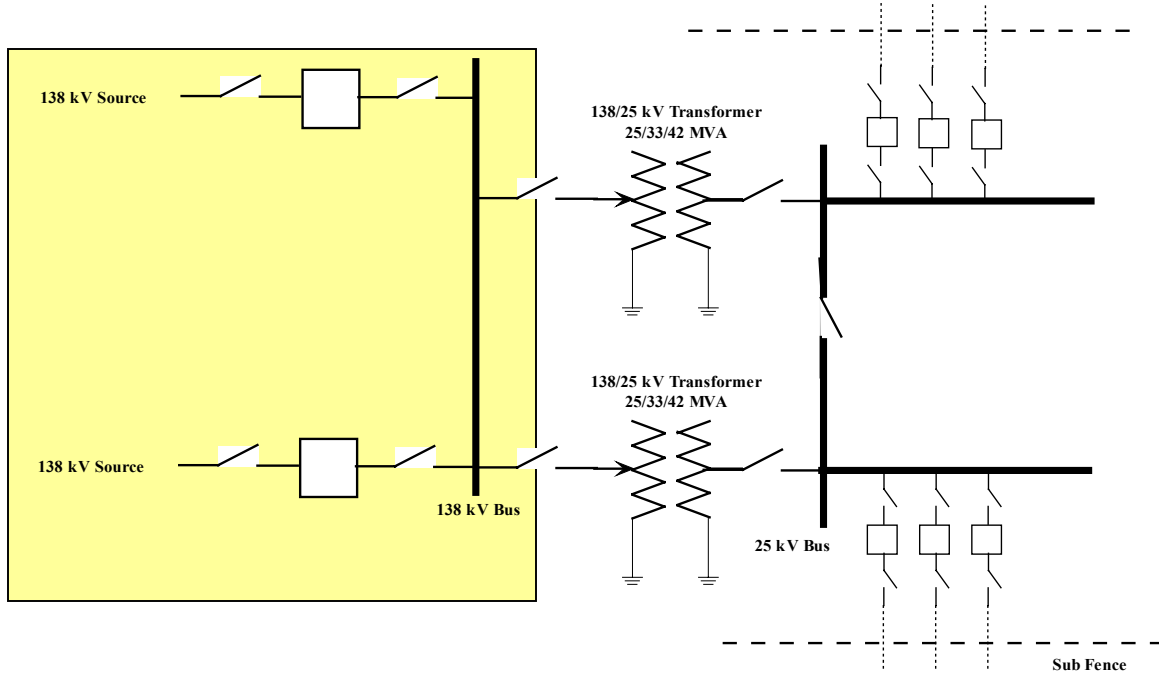


Figure 16 Local System Components of a Double Transformer Substation



4.1 Alignment With Contribution Policy

The definitions of Local System and POD related costs relate to the functionalization of the transmission system. The definitions associated with the Customer Contribution Policy (i.e. customer-related and system-related facilities) are used to assess costs when connecting new customers to the transmission system.

Customer related facilities are those facilities that must be built to interconnect a new customer. While these facilities may only serve one customer at the time of construction, these facilities may at some point be used to serve other customers, and may be included in more than just the POD function. The cost of customer related facilities, and the Contribution Policy are important to new and existing customers because they determine how much a new customer must pay, and how much existing customers must pay when a new customer is connected to the system. The proper determination of the cost of customer related facilities helps ensure equitable recover of costs between new and existing customers. Generally, customer related facilities are similar to the POD function.

The purpose of defining functions of the transmission system is for producing a cost study with respect to the embedded costs of the system. This ensures that all customers are allocated costs of the transmission system proportional to their use of the system to ensure equity between customers.

The TCCS functional definitions and Customer Contribution Policy definitions do not align perfectly because they have different purposes.

Substation facilities to accommodate a new customer would be considered customer-related under the AESO's contribution policy, but could involve a networked substation that includes both POD and Local facilities as per the functional definition discussed above.

Alignment of functional definitions with existing Customer Contribution definitions may involve trades offs in accuracy between which costs are functionalized as POD and which costs are determined to be customer-related in a contribution calculation.

4.2 Conclusion

The cost data from the TFO's does not provide sufficient breakdown to study transmission costs with the refined functionalization definitions discussed above. It is not expected that additional detail will allow a precise assessment of the impact in the near future.

Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the TCCS.

5. POD COSTS

The TCCS studied the cost of POD substations owned by AltaLink and Atco Electric. The study found that 56% of POD substation costs were fixed, and that 44% of the costs varied with demand on the basis of a zero intercept study.

The cost of POD's (TFO substation and radial line cost data) in relation to capacity exhibits variation because the TFO data does not separate out the Local System as defined in the preceding section, and the cost data is NBV. These factors diminish the relationship between capacity and cost. Older points of delivery will exhibit low NBV, as will points of delivery that have CIAC accounted for against the cost of the POD. Points of delivery that include more line costs or high side equipment will exhibit higher costs.

The NBV cost data provided by the TFO's does not have sufficient detail to further break down these costs.

The AESO has studied recent projects where additional cost detail is available as part of its contribution policy study. The AESO study has found that on the basis of new PODs, somewhat more than half the costs are customer related, and somewhat less than half the costs are demand related which is consistent with the findings of the TCCS study based on embedded costs. PS Technologies therefore understands the AESO will rely on the contribution policy study data for additional analysis of POD costs.

6. REFINEMENTS TO THE COST CAUSATION STUDY

The Transmission Cost Causation Study was conducted with out data that linked specific transmission facilities with CIAC for AltaLink facilities, and therefore, CIAC was left out of the original study. This CIAC is now taking into consideration in the functionalization of facilities.

The Transmission Cost Causation Study functionalized dual use facilities (serve both generation and demand) on the basis of original purpose of transmission facilities and therefore was functionalized as either POS (Bulk) or POD. The dual use facilities can be functionalized on the basis of the substation fraction, and this refinement is completed below.

6.1 Contributions in Aid of Construction (CIAC)

This section of the update reviews the alignment of CIAC with functions in the TCCS Study (Bulk, Local and POD).

Atco Electric was able to correlate CIAC by facility and provided the data on a facility-by-facility basis. Therefore, CIAC was functionalized in the same manner as the facility that was constructed when the CIAC was collected. CIAC offset the NBV of transmission system facilities in all of the functions including POD, Local and Bulk System facilities. The Bulk System facilities that were offset with CIAC include 240 kV lines, POS substations and Dual Use substations.

AltaLink did not track CIAC by facility, and all of the NBV's for AltaLink facilities were based on original cost less accumulated depreciation. CIAC was treated as a separate account in the case of AltaLink. AltaLink's CIAC was reviewed and assessed as 22% being related to STS service, and 78% being related to DTS service. The STS amounts were functionalized as POS (Bulk), while the DTS amounts were functionalized as POD and offset property in the POD function. AltaLink's CIAC has been functionalized in this manner and the impact of this change is shown below.

6.2 Dual Use Substations

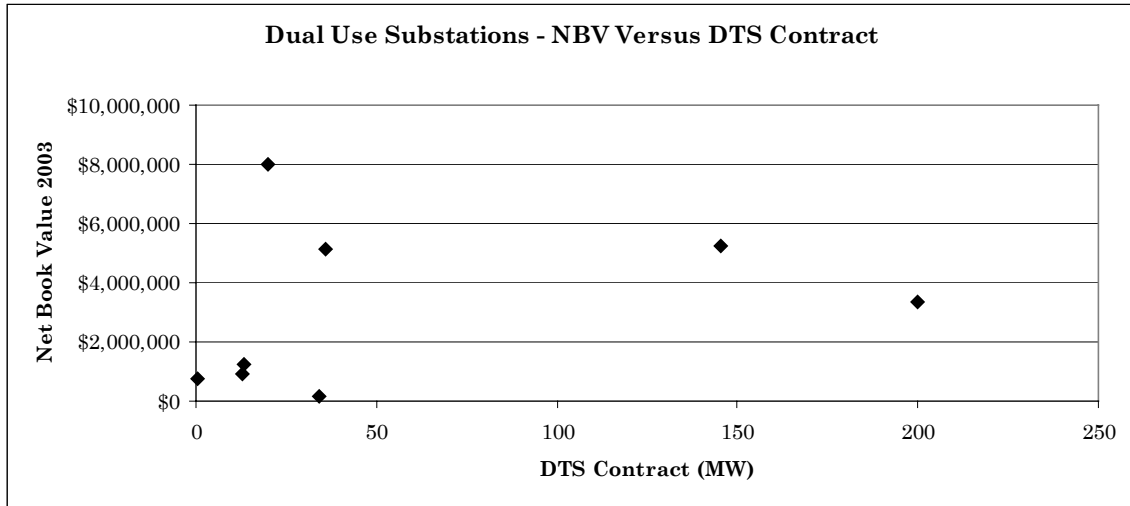
The cost of Dual Use substations as treated in the original TCCS was reviewed on a case by case basis. When a substation was originally built to serve load, and a generator was later connected to the substation, the cost was functionalized as a POD substation. When a substation was built to interconnect a generator(s), the cost of the substation was functionalized as POS and therefore as a Bulk System. All of the substations interconnecting the generators that existed prior to 1996 were functionalized as POS and as Bulk System.

Substation fractions as implemented in the AESO's final 2006 tariff were not used in the TCCS Study and substations were functionalized on the basis of their original purpose as discussed above.

The cost data for the TCCS Study was based on 2002/2003 data and does not include all of the Dual Use substations that exist today. The Dual Use substations that provide service to the generators that were in existence prior to 1996 were functionalized as Bulk System. The newer Dual Use substations were functionalized as either POD or POS depending on the original purpose of the substation. Substations that are owned by generators are not included and do not appear in the TFO list of facilities.

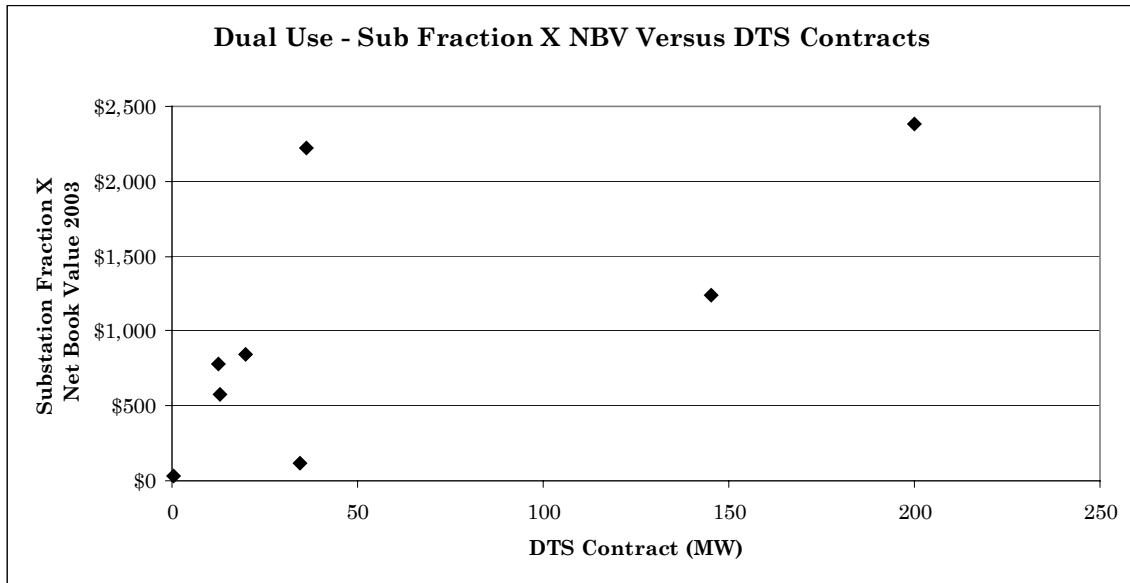
The following chart shows the NBV of substations versus the DTS contract level.

Figure 17 NBV of Dual Use Substations versus DTS Contract Level (MW)



The correlation between NBV and load is weak. Dual use substations will provide a challenge for correlation because some substations were sized to serve the load with little or no regard for generator size, while other substations were sized to accommodate the generator with little or no regard for the load while other substations have DTS and STS load/supply of similar magnitude.

Figure 18 NBV of Dual Use Substations (X Sub Fraction) versus DTS Contract



The relationship between cost and size of Dual Use facilities does not bear a strong relationship when viewing embedded costs. The cost of generators that existed prior to 1996 were not included in these charts because these facilities are generally very old in relation to plant built in the last 10 years. The different vintage of facilities is one factor that distorts the relationship between cost and DTS contract capacity.

The functionalization of dual use facilities is completed on the basis of substation fractions as shown below.

6.3 Impact of Refinements

Accounting for CIAC as described above, and refunctionalizing dual use facilities using substation fractions results in a change to the functionalization contained in the original TCCS as follows.

Table 4 Adjustments to Functionalization for CIAC and Dual Use

TCCS Functionalization of Alberta's Transmission System			
Based on % NBV Property	Bulk System	Local System	POD
Functionalization	45.7%	15.7%	38.6%

Translation into 2002/03 NBV			
Based on % NBV Property	Bulk System	Local System	POD
Functionalization	677,560	232,841	571,508

Offset of CIAC for AltaLink Facilities			
	Bulk System	Local System	POD
Functionalization	5,771	0	20,463

NBV with compensation for AltaLink CIAC			
	Bulk System	Local System	POD
Functionalization	671,789	232,841	551,046

NBV Removal of Dual Use with Original Functionalization			
	Bulk System	Local System	POD
Functionalization	-13,935	0	-11,076

NBV Addition of Dual Use Facilities with Substation Fractions			
	Bulk System	Local System	POD
Functionalization	16,782	0	8,229

NBV with compensation for AltaLink CIAC and Dual Use			
	Bulk System	Local System	POD
Functionalization	674,636	232,841	548,199

Updated Functionalization of Alberta's Transmission System - 2002			
Based on % NBV Property	Bulk System	Local System	POD
Functionalization	46.3%	16.0%	37.7%

This adjustment in functionalization also flows through to subsequent tables and the following tables are revisions to the TCCS Study.

Table 5 Adjustments to the TCCS Study

Revised Table 21 - Summary of Functionalization with CIAC and Dual Use Compensation

Based on % NBV Property	Bulk System	Local System	POD
Functionalization	46.3%	16.0%	37.7%

Revised Table 22 - Conversion of Property to Annual Revenue Requirement - 2003

Direct Conversion of Function NBV Property to Rev Req - 2003				
	Bulk System	Local System	POD	Rev Req
Revenue Requirement	177,595	61,294	144,311	383,200
Less RGUCC (2003)	30,598			30,598
Rev Req from DTS	146,997	61,294	144,311	352,602

Table 23 Classification of Costs in Each Function

Classification of Alberta Transmission Costs by Function			
Classification	Bulk System	Local System	POD
Demand (CLMS-NCP)	81.5%	82.5%	43.1%
Energy	18.5%	17.5%	0.7%
POC/Customer			56.2%

Revised Table 24 Conversion of Classified Costs to Annual Revenue Requirements

Classification based on TCCS Costs					
TCCS Costs	Bulk System	Local System	POD System	Classified RR	% of RR
Demand Related Cost	119,802	50,568	62,198	232,568	66.0%
Energy Related Cost	27,194	10,727	1,010	38,931	11.0%
POD Related Cost	0	0	81,103	81,103	23.0%
Total	146,997	61,294	144,311	352,602	100.0%

7. OPERATIONS, MAINTENANCE AND ADMINISTRATION

The TCCS study was based on the assumption that OM&A costs were proportional to property. This assumption was made because OM&A costs are a small part of the total revenue requirement, and additional data was unavailable. OM&A accounts for approximately 25% to 33% of the total revenue requirement for a TFO.

One concern of interveners is that some facilities are older than others, and that OM&A should be studied to reflect the vintages that exist. A high level review of depreciation studies shows that substation facilities and transmission facilities have a similar remaining composite life. Based on similar remaining composite lives, it is not apparent that some facilities would have significantly different levels of OM&A costs associated with their operation.

TFO GTA's contain some information regarding the components of OM&A but this information is insufficient to functionalize OM&A costs in alignment with the functional definitions in use in the TCCS Study. Additional study would be required to determine the OM&A of facilities as they age.

Conventional wisdom indicates that OM&A costs increase as facilities age and this relationship for facilities in Alberta must be understood to properly functionalize these costs.

The OM&A costs were not studied because work was focused in other areas such as classification of Bulk System costs. A study of OM&A costs must ensure that functionalization of OM&A costs is aligned with the functions in the cost study, and that the current distinction between Local System and POD system may change.

OM&A costs may vary by vintage, whereby old facilities require more funds to maintain than do newer facilities. OM&A costs may also vary by equipment type, whereby substation equipment requires a different types of

maintenance than do transmission lines (vegetation management is required for lines while switch gear maintenance applies only to substations).

The breakdown of AltaLink and Atco Electric TFO facilities show that each function has a different make up of equipment type as follows:

Table 6 Transmission Facility Type by Function

	Bulk	Local	POD
Substation	43.6%	10.8%	90.9%
Line	53.4%	86.6%	5.8%
General	3.0%	2.5%	3.3%
Total	100.0%	100.0%	100.0%

The relative age of equipment is estimated by dividing the accumulated depreciation by the property, plant and equipment amount. The AltaLink data for 2003 shows that both transmission lines and substations have accumulated depreciation of between 50% and 60%, indicating that the relative ages are similar.

Table 7 Depreciation of Transmission Facilities

	2003 PPE	2003 Acc Dep	Acc Dep % of PPE
Substations	659.7	343.5	52.1%
Lines	657.3	388.4	59.1%

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about ¼ of the revenue requirement,
- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,
- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.

8. RECOMMENDED ADDITIONAL ACTIVITIES

Local System and POD

Further study regarding the distinction between Local System and POD should be completed following the review of the Customer Contribution Policy.

The TCCS study proposed a distinction between Local System and POD that aligns with the concept of common facilities (useful to more than one point of delivery) and dedicated facilities (dedicated to one point of delivery). The Customer Contribution Policy uses different distinctions.

If definitions are refined, the TCCS should be reviewed and updated. This updated study would provide a new basis for the fixed and demand related costs associated with POD's.

OM&A

A new study of OM&A should be conducted to facilitate the functionalization of OM&A. The relationship between age and OM&A should be studied as well as the relationship between OM&A and equipment type. This study would provide for an improvement in the functionalization of approximately $\frac{1}{4}$ of the transmission revenue requirement.

The data required for such a study is not currently available. The development and compilation of this data would require a considerable effort and would require details of O&M expenditures by facility and by equipment type over the life cycle of transmission and substation equipment. Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.

9. APPENDIX A

Transmission Cost Causation Study Activities

Based on the EUB direction, stakeholder comments, and background information provided in the preceding section, the AESO proposes that the *2006 Cost Causation Study* include the following eight activities.

1. **Bulk System** — Study all of the major bulk paths (between 20 and 30 paths) to determine the relationship between the time of maximum stress and the time of peak system load. Review the functionalization of bulk system and local system to ensure continuing consistency with AESO planning. This study component would primarily use technical data from the 500 kV N-S Need Application as the basis, as well as additional data from more recent planning studies prepared by the AESO, if necessary.
2. **Interties** — Review the treatment of intertie facilities (the Alberta-BC and Alberta-Saskatchewan interconnections) in the *2006 Cost Causation Study*, including the context of this treatment under current legislation and regulation. If appropriate, study and recommend a means to separate the costs of intertie facilities from domestic facilities within Alberta. This study component would utilize the 2003 cost data used in the original study.
3. **Local System and POD** — Study and recommend a means to better differentiate between the Local System and POD functions. Ensure definitions align with usage elsewhere in the AESO tariff (specifically, within the terms and conditions of service). This study component would utilize the 2003 cost data used in the original study.
4. **POD** — Study POD costs in more detail, including more detailed analysis of POD cost components, how POD costs vary with load size, and whether such variation is linear or follows some other pattern. This study component would utilize the 2003 cost data used in the original study. As well, this study component would be coordinated with, and potentially use additional detailed data from, the investment level study being conducted as part of the AESO's 2007 terms and conditions consultation.
5. **Contributions** — Enhance the *2006 Cost Causation Study* by more precisely including the effect of contributions in aid of construction. Study the alignment of contributions with bulk system, local system, and POD functions, and develop a methodology to align and correlate contributions with facilities. This study component would primarily utilize the 2003 cost data used in the original study.
6. **Dual-Use Substations** — Review costs associated with transmission service at dual-use substations in the context of the AESO's 2006 rate structure (including the use of substation fractions), to ensure alignment between the POD charge in the DTS rate and the Primary Service Credit. For each of the 18 dual-use substations (excluding Fort Nelson) identified in section 4.10 of the AESO's 2006 GTA, assess the costs, revenues,

Revised February 16, 2006

ownership, contributions, contract levels (DTS and STS), and any other relevant factors affecting the incurring and recovery of costs by the AESO. Propose a mechanism to fairly recover costs at dual-use substations.

7. **Operations, Maintenance, and Administration** — Enhance the *2006 Cost Causation Study* by studying operations, maintenance, and administration costs and causation relationships to determine if these costs should be functionalized and classified in the same manner as TFO capital-related costs. If appropriate, use the results of the study to revise the functionalization and classification of such TFO costs. This study component would primarily use additional information from TFO tariff applications.
8. **Recommended Additional Activities** — Include recommendations for future enhancements of the *2006 Cost Causation Study*, based on review of the comments made by stakeholders in the AESO's 2005-2006 GTA proceeding, on input from stakeholders during the 2007 rate consultation, and on results of the activities listed above. Future enhancements may include:
 - assessing whether customers were responding to the price signals given by the DTS rate, and, if so, how and in what manner those responses were affecting transmission system planning, and
 - differentiating depreciation and return by vintage of assets (also referred to as “normalizing” data for vintage).Assess whether it is worthwhile and appropriate to complete these enhancements and, if so, propose a schedule for addressing them in a future study or tariff application.

The AESO expects that the *2006 Cost Causation Study* will primarily rely on the 2003 cost data utilized for the original *Transmission Cost Causation Study*. The AESO notes that the analysis in the study results in percentages of property by function and classification, and such percentages would not be expected to vary materially over a one or two year period.

The AESO also notes that separate consultation is being conducted on 2007 terms and conditions, import and export tariffs, and merchant interconnection tariffs. Although the rates to be included in the AESO's 2007 tariff application must align with and complement those other components of the tariff, the *2006 Cost Causation Study* refinements will focus solely on rates matters.

The *2006 Cost Causation Study* activities will be conducted from February to April of 2006. A status report included preliminary results (where available) will be provided at the end of March, and final results at the end of April. Stakeholders will be invited to comment on the preliminary and final results, and responses to stakeholder comments will be incorporated into the final report for the study, where appropriate.