

ALBERTA TRANSMISSION SYSTEM  
WIRES ONLY - COST CAUSATION STUDY

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PREPARED FOR

ALBERTA ELECTRIC SYSTEM OPERATOR (AESO)

PREPARED BY

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## 1. Executive Summary

The AESO has commissioned PSTI to produce this study to address AEUB Directives and to provide guidance for rate design at the time that the Transmission Regulation comes into effect (January 1, 2006).

This report investigates embedded transmission wires costs in response to directives contained in Decision 2001-32 where the AEUB directs the AESO “to determine the appropriate classification of supply and load customer transmission costs to demand and energy”<sup>1</sup>. This report does not review cost causation of losses, ancillary services and other system support services.

The transmission system wires costs are currently recovered from both supply and demand customers. Following implementation of Transmission Regulation, transmission wire costs will be recovered from demand customers (except the point of supply costs associated with the generating units). This change adds focus to the review of causation of transmission wires costs.

Completion of this study included data gathering of wires cost from the four major transmission facility owners. The net book value by transmission facility was requested in order to provide a view of embedded costs for consistency with revenue requirement.

The findings of this report are summarized as follows:

### Functionalization of Alberta's Transmission System

% of NBV Property	Bulk System	Local System	POD
<b>Recommendation</b>	<b>45.7%</b>	<b>15.7%</b>	<b>38.6%</b>

### 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%
POD/Cust			56.2%

Please note that demand related costs are associated with NCP (non coincident peak) for POD, and CLMS (coincident load to maximum stress) for the Bulk System.

<sup>1</sup> EUB Decision 2001-32, page 124.

## 2. Evolution of Transmission Wires Cost of Service

The nature of cost causation for transmission service is an evolving science. The cost of transmission service within the context of the vertically integrated structure was small in comparison to total cost and therefore transmission costs were not normally the focus of attention. In the current industry structure, the cost of the transmission system is distinct and visible, and the subject of a General Tariff Application independent of other electricity costs such as generation and distribution.

Prior to the current industry structure, transmission costs in Alberta were pooled within the Electric Energy Marketing Act (EEMA). The pooled costs coming out of EEMA were used by the vertically integrated utilities in their Cost of Service Studies to allocate upstream costs to the various rate classes for end use customers.

The Electric Utilities Act of 1995 changed the industry structure on January 1 1996. The Act required separation of the generation, transmission and distribution functions. Starting in 1996, the distribution utilities were subject to the transmission administrator (now the independent system operator, currently the AESO) tariff for System Access Service (SAS). The AESO's rate structure drives cost causation in electric distribution Cost of Service Studies.

The AESO's rate structure is not indicative of its costs, since the AESO makes fixed monthly payments to the various transmission facility owners (TFO). Each of the TFO's tariffs to the AESO is based on revenue requirements approved by the TFO's regulatory board.

In order to conduct a Cost Causation Study on transmission, PSTI went back to basics. PSTI entered confidentiality agreements with TFO's in order to obtain detailed net book value data by transmission line and substation. PSTI also reviewed planning practices that result in the addition of new facilities.

Performing a Cost of Service Study on transmission alone is not a common practice and therefore, there is no one common or standardized method for conducting such a study. This study will look at transmission costs in Alberta from a number of views, and will provide a recommendation as to the most appropriate way to functionalize and classify transmission costs in order to be of assistance to the AESO in its rate design.

This study has been called a Transmission Cost Causation Study, and is similar to a Cost of Service Study. This study functionalizes and classifies costs in the same manner as a Cost of Service Study. A Cost of Service Study has the final step of allocation of costs to rate classes. This Cost Causation Study does not allocate costs to rate classes because there will only be one rate class in 2006.

## **2.1. Alberta Allocation of Transmission Wires Costs**

Traditionally, costs of service studies have treated transmission as one function. The cost of this transmission function was classified on the basis of demand coincident to system peak. Each rate class demand at the time of system peak, relative to the total system peak determined the proportion of transmission costs for which that the rate class was responsible.

Alberta historically had a winter peaking system, and transmission was planned to meet the annual peak load. As Alberta's annual load profile became flatter with the addition of irrigation and air conditioning load in the summer and with the addition of high load factor industrial load, some areas in the province experience peak loading in the summer. Transmission costs from EEMA were based on the coincident peak load in each month, with a 75% weighting on the 3 winter months, and a 25% weighting on the 9 non-winter months.

Alberta loads continue to grow and shift. Southern Alberta is now predominately summer peaking and some areas may have a winter peak one year, and a summer peak in another year depending on weather. Further, thermal capacity ratings on electrical equipment are lowest in the summer, requiring planners to consider equipment loading on a seasonal basis.

A review of peak load conditions shows that 44% of the transmission points of delivery now peak in a season other than winter.

Alberta adopted a transmission tariff whereby generators and loads were required to pay for access to the transmission system. Alberta Energy released a Transmission Policy Paper that changes cost responsibility and will result in a transmission tariff that recovers the cost of transmission wires from load. The new transmission tariff will come into effect on January 1, 2006. Please refer to Appendix A for an extract from "Transmission Development – *The Right Path for Alberta* – A Policy Paper, December 22, 2003".

Section 30(3)a of the Electric Utilities Act dictates that the rate for transmission system access service must be the same for all distributors and transmission connected load, regardless of location on the transmission system. While this section has an impact on Rate Design, it does not impact a Cost Causation Study. Please refer to Appendix B for an extract of the Electric Utilities Act regarding the transmission tariff.

### **3. Methodology Overview**

The general methodology for this study is to perform a traditional cost of service study (without allocation) on the wires component of the transmission system.

The methodology includes functionalization of the transmission system (or sub-functionalization since transmission itself is considered a function in traditional electric utility Cost of Service Studies). The costs of each function are reviewed to see how the costs are incurred, and the costs of each function are classified as customer, demand or energy related. The last step in a traditional Cost of Service Study is the allocation of costs to each rate class. This study does not include the allocation of costs to rate classes because load customers form the only rate class.

This study reviews the embedded cost of transmission, and is not a marginal cost study.

Data availability presented some challenges in completing the study. The TFO's do not have a uniform system of accounts and limited data availability constrains the potential methods used to perform a Cost Causation Study on transmission wires only.

### 3.1. Costs within Scope for this Study

The focus of this study is the cost of transmission facilities, commonly referred to as wires costs. The wires costs for the purpose of this study include the cost of planning, financing, owning, operating, maintaining and administering physical transmission facilities. This translates into the total revenue requirements from the TFO's plus AESO's own costs and other industry costs.

The total AESO revenue requirement for transmission is larger than the focus of this study because it includes the cost of line losses and ancillary services.

This study will review Wires, Other Industry Costs and AESO's own costs without considering costs of ancillary services and losses as shown in Table 1 for costs in 2003 and 2004.

**Table 1 Revenue Requirement**

Transmission Wires and Administration Costs are \$ X 1m unless otherwise specified <b>Cost Data</b>	Existing 2003
Wires Costs	346.50
Other Industry Costs (1)	16.00
AESO's Own Costs (1)	20.70
<b>Transmission Costs.</b>	<b>383.20</b>

(1) Forecast of 2004 Costs

This study is based on the assumption that the revenue requirement is directly proportional to the property on the basis of net book value. Since the study is based on property, the results of the study are expressed in percent of property, and the final step is the translation of percent of property back to an equal percent of revenue requirement.

Transmission property information was available from the four largest TFO's. AltaLink provided transmission property data as of April 30 2003, of original cost, depreciation, and net book value by substation and by transmission line number. Atco Electric was able to provide transmission property data as of December 31 2002, of original cost by substation and transmission line number and depreciation was based on the system average depreciation. Transmission property data from EPCOR and Enmax did not include enough detail to allow

analysis of the data in the same manner as for AltaLink and Atco Electric. The sum of net book value of transmission property with details suitable for analysis (AltaLink and Atco Electric) is \$1.2 billion, and the sum of net book value of transmission property from the four largest TFO's is \$1.5 billion.

### **3.2. Cost Causation - General**

The cost of an electric transmission system consists of capital and operating costs associated with electric transmission facilities in use. The electric transmission industry is capital intensive and wires costs tend to be fixed in nature.

Since electric transmission system costs are capital intensive, decisions made at the planning stage drive costs over the life of the transmission facilities. Therefore, understanding the transmission planning process is crucial to understanding cost causation for a transmission system.

Transmission planning is complex, and is normally simplified to a process of meeting various transmission planning criteria. Violations of one or more transmission planning criteria identify the need for new facilities. Transmission planning criteria are rules of thumb based on experience and judgment. Transmission planning criteria are sometimes referred to as reliability criteria, but planning criteria are more than reliability criteria. The violation of transmission planning criteria indicates that the transmission system will be inadequate to meet customers needs and that inadequacy may manifest itself in various forms including problems in safety, operability, reliability, etc. Transmission planning criteria are applied to a forecast condition such as single contingency (N-1) at the hour of peak load, double contingency (N-2) at the hour of peak load, single contingency and loss of critical generator (N-1-G) at the hour of peak load, etc.

Transmission planning criteria normally include stability related, voltage related, and thermal capacity related criteria. Transmission facilities may also be justified on the basis of the economics in the reduction of line losses and ancillary services. The addition of new transmission facilities will impact all transmission parameters, including economics. Transmission planners will optimize the overall system over time by changing the system configuration and adding facilities as required.

When a transmission planning criterion is in violation, transmission facilities may be added or removed to eliminate the violation. On the basis that transmission planning criteria consider the power flow and demand at one point in time, costs associated with adherence to transmission planning criteria are often considered demand related. This is a simplistic view that fails to recognize that transmission planning criteria were developed based on experience and judgment to ensure a reliable transmission system for the entire year, and not just one point in time (the point of peak stress – typically peak load).

### **3.3. Overview of Functionalization**

The purpose of functionalization is to separate the system into various functions, and to allow the separate study of each function. At a high level, total transmission costs may be functionalized as shown in Table 2 as per AEUB Decision 2003-077.

**Table 2 2003 Costs Functionalized**

<b>2003 Revenue Requirement</b>	
Wires Costs	\$346.5
Ancillary Services	\$208.4
Losses	\$142.7
Other Industry Costs	\$16.0
TA Administration	<u>\$20.7</u>
Total	\$734.3

As indicated in Section 3.1, the costs within the scope of this study include Wires Costs, Other Industry Costs and TA Administration and the other items are considered elsewhere.

The transmission system wires costs will be viewed as providing three functions, bulk delivery of electric energy, local delivery, and the points of delivery. The bulk system delivers large amounts of electric energy to a large group of customers, while the local system provides service to a small group of customers, while the point of delivery provides service at one location, generally to one customer. These functions are further defined in Section 4, along with examples and explanations.

### **3.4. Overview of Classification**

The costs of each function are classified on the basis that costs are incurred. Historically, and as discussed earlier, transmission costs were considered one function, and total transmission costs were classified as demand related and were based on the coincident peak demand (CP), or some variation of coincident demand. Transmission systems in other jurisdictions generally continue to be classified as demand related with demand measured as coincident to the annual peak (1 CP), or a variation thereof such as 3W/9NW.

While transmission planning models consider one point in time, transmission planning criteria are based on experience and judgment to ensure reliable operations year round, and planners consider the optimization of conductor to optimize the cost of wires and losses. Transmission planning is often used as justification for classification of costs by demand, because transmission planners typically consider the demand under various scenarios. In the event that transmission planning criteria are violated, the transmission system is upgraded to accommodate the forecast demand. However, transmission planning criteria are based on experience and judgment, and therefore, it is too simplistic to classify transmission wires costs as all demand related.

Two approaches are used to classify the costs associated with the transmission functions, and these approaches are the zero intercept approach, and the minimum system approach. These approaches have been used to classify the costs of distribution systems, but have not been used in the case of transmission systems. However, transmission systems have similarities to distribution systems with respect to the fixed nature of wires costs, and the approaches to classifying costs for distribution systems, can also be used for transmission systems. The zero intercept approach is used to determine customer related costs, and the remaining costs are classified as demand and energy on the basis of the minimum system approach.

### **3.5. Allocation**

The exercise of allocation is normally the last step in a Cost of Service Study. The rate class parameters of demand, energy and count are applied to costs according to classification, and the result is a cost to serve by rate class. In this Cost Causation Study, we contemplate only one rate class as outlined in the Transmission Policy, (the DTS rate class) and this step is not required.

### **3.6. Review of Literature and Cost of Service in Other Jurisdictions**

A review of Cost of Service Studies and literature shows that there is no standard methodology to conduct a Cost of Service Study on a transmission system by itself. The concept of conducting a Cost of Service Study on transmission alone is relatively new and is a result of industry restructuring, and the segregation of the vertically integrated utilities. Cost of Service Studies on distribution systems alone are more common.

Independent distribution systems have existed for some time and methods for performing Cost of Service Studies on distribution system have developed. The National Association of Regulatory Utility Commissioners (NARUC) published *Electric Utility Cost Allocation Manual* (Washington, 1992) which identifies standard methods for demand and customer classification of distribution plant. The Minimum System, and Zero Intercept Approaches form the basis for classifying distribution plant as customer or demand related.

Cost accountability (generation and load) varies across Europe<sup>2</sup>. Transmission rates varies widely across Europe where some countries impose a small fixed charge on consumers, to countries where demand charges consists of more than 80% of the total rate (Germany), to countries where the entire transmission rate consists of a variable charge (energy based)<sup>3</sup>. While cost accountability is being set by Regulation in Alberta, and rates must conform to Legislation, there is no restriction on methodology to perform a Cost Causation or Cost of Service Study in Alberta.

Transmission systems generally are viewed as one function, even though there is general recognition that some parts of a transmission system serve a large number of diverse customers, while other parts of the transmission system are dedicated to the service of one customer. Ontario “functionalizes” its transmission system<sup>4</sup> into three pools: network, transformation, and connection. The network pool consists of all looped transmission lines, high voltage switching and substations, the transformation pool consists of substation facilities that transform voltage from above 50 kV to below 50 kV, and the connection pool consists of radial parts of the system

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<sup>2</sup> Benchmarking of Transmission Pricing in Europe, European Transmission System Operators Task Force, March 2003.

<sup>3</sup> Benchmark of Electricity Transmission Tariffs, DG TREN/European Commission, October 2002.

<sup>4</sup> Decision RP-1999-0044 – With Reasons, Ontario Energy Board, May 26 2000.

connecting a customer to the network. Transmission property in the network, transformation, and connection pools accounts for 58%, 26% and 16% of the total property respectively. The rate for the network pool is 100% demand based, and billed on the higher of the customers demand coincident to the monthly peak demand, or 85% of the customer's peak demand during the peak period of the month. The rate for the transformation and connection pool is recovered on the basis of demand and is applied to the customer's peak demand (NCP) during the month. Ontario Hydro Networks did not complete or file a Cost of Service Study, and the rate design was based on an "assessment of the options".

PJM performs a very simple transmission wires cost of service and rate design on the basis that all costs are incurred on the basis of transmission being one function (network) within each zone, and costs are classified as demand related (1 CP). The New York ISO (NYISO) has not performed a cost of service study on the wires only costs. The California ISO (CAISO) completed a rate design exercise on the basis of a review of costs, allocation and assessment of costs, but have not completed a formal cost of service study.

Based on a review of transmission wires only Cost of Service Studies in other jurisdictions, there was no one approach that stood out as a good methodology for use in Alberta.

## 4. Functionalization

The transmission system has traditionally been treated as one of the three electric industry functions (generation, transmission and distribution) within the vertically integrated utilities. For the purpose of this study, the transmission function will be further separated into “sub-functions” and for simplicity in this report; these will simply be referred to as functions.

Legislation provides some boundaries as to the system at issue. The definitions in the Electric Utilities Act 2003 are as follows, and the purpose, or function of the transmission system is highlighted:

(ccc) "transmission system" means all transmission facilities in Alberta that are part of the interconnected electric system;

and

(bbb) "transmission facility" means an arrangement of conductors and transformation equipment **that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer** operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes

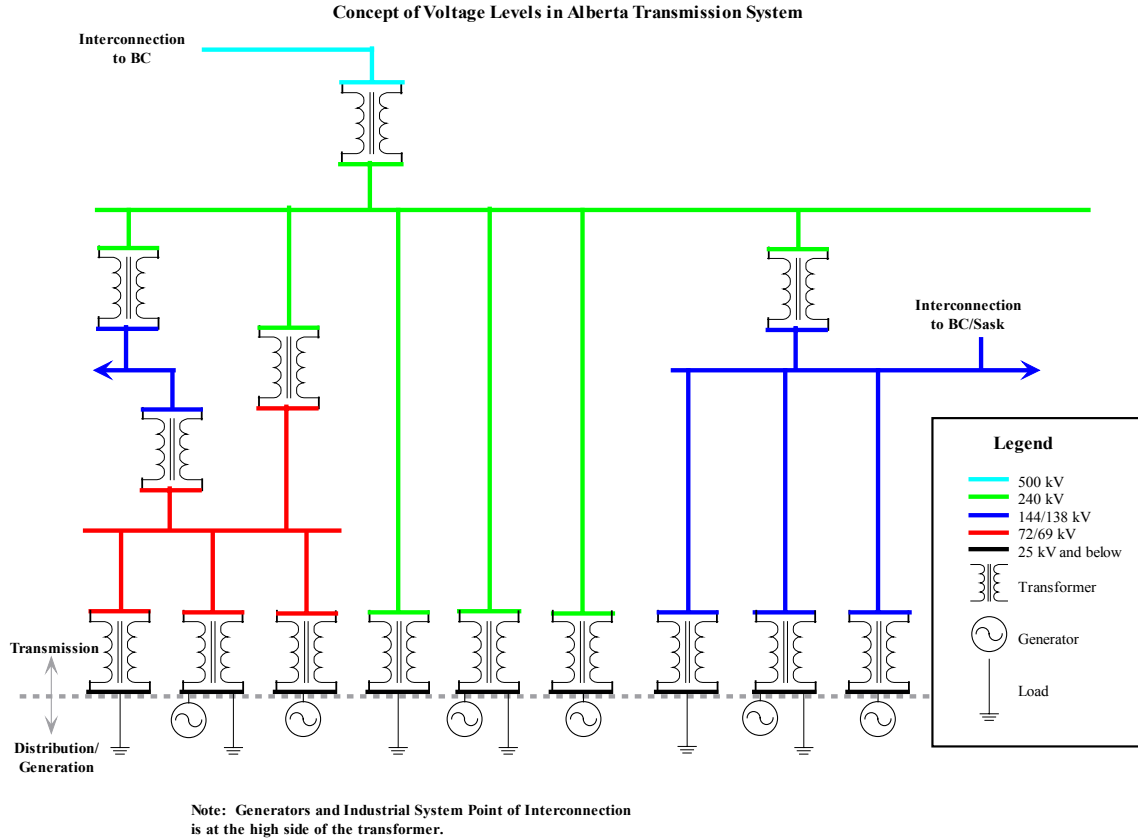
- (i) transmission lines energized in excess of 25 000 volts,
- (ii) insulating and supporting structures,
- (iii) substations, transformers and switchgear,
- (iv) operational, telecommunication and control devices,
- (v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from
  - (A) the low voltage terminal, to
  - (B) electric distribution system lines that exit the substation and are energized at 25 000 volts or less,

and

- (vi) connections with electric systems in jurisdictions bordering Alberta, but does not include a generating unit or an electric distribution system;
- also,
- (t) "farm transmission costs", in respect of an owner of an electric distribution system, means
    - (i) the proportion of the owner's costs of supplying electricity on 25 000 volt lines to the service area boundaries of rural electrification associations that the total electricity supplied to rural electrification association members within those boundaries for farm and farm irrigation purposes bears to the total electricity supplied on those lines, and
    - (ii) an equivalent dollar amount per unit of electricity supplied by the electric distribution system to farm and farm irrigation customers who are not members of rural electrification associations;

While the legislation defines what the transmission system is, and what it does, there are no constraints in how the transmission system is further functionalized for a Wires Only – Cost Causation Study.

The following chart shows the various transmission system configurations common in Alberta and the lines are colour coded by voltage level.

**Figure 1 Alberta Transmission System Configuration by Voltage Level**

This illustration shows that generation occurs at low voltage (typically below 20 kV). The electricity may be stepped up to 25 kV, 69/72 kV, 138/144 kV, 240 kV or 500 kV before being transported to its point of consumption, which is again at low voltage. This illustration shows that the transmission system is not a linear system whereby all of the electricity is stepped up to the high voltage system, and then stepped down at the point of consumption, in a linear manner. Electricity may never be stepped up in the case of a generator and load being connected at the same 25 kV bus. Electricity may be stepped up to any transmission level (and may be stepped up more than once) before being stepped back down for consumption. This observation of a non linear system from generation to highest voltage back down for consumption indicates that voltage based costs have shortcomings when used to define a function of the transmission system.

The approach of two functions (system and customer dedicated) was rejected because there was no simple, reliable and defensible way of defining and separating costs in these two functions. A facility considered system in one instance, may be considered customer dedicated in another

similar situation or at a different point in time depending on changing system configuration and circumstances.

Voltage levels were considered as functions because voltage levels are easily identifiable and the low voltage level for transmission is already in place in legislation. While costs by voltage level are available for some components of the system, voltage level costs do not tell us how costs are incurred. Planners of the transmission system may best assist in understanding how costs are incurred. Voltage level alone falls short of defining a function because voltage level does not define purpose. Further, voltage level is not sequential as shown in Figure 1, and therefore, voltage levels fall short for defining a function.

The transmission planning process was reviewed for assistance in the definition of functions. Transmission planning of the bulk system occurs separately from planning of the local, or regional transmission system. While the planning may occur separately, the planning must occur in a coordinated manner to ensure a reliable electric transmission system. Planning of substations, or points of delivery requires unique information, and forms the basis for the last of three transmission functions.

#### **4.1. Definitions of Transmission Functions**

The development of definitions for each transmission function was iterative. The various configurations of the transmission system were examined, and tested to determine the best definitions of functions. As cost of service studies for transmission systems evolve, definitions for each function may be refined. The following definitions were developed in the process of completing the Causation Study. Transmission facilities may change from one function to another over time as the system evolves. For example, in the 1950's, 138 kV lines served as bulk system, and over time, additional points of delivery were added to these lines and today they serve the function of a local or regional system.

**Bulk System:** The bulk system delivers bulk electric energy (large volume) over a long distance to a number of users. The bulk system is the transmission system covering an area with the largest capacity to import or export electric energy into a region. The bulk system is commonly understood to be the overlying transmission system, and includes at a minimum, most of the 240 kV and all of the 500 kV lines in Alberta. The bulk system also includes switching stations and substations with transformation between two transmission voltages, but does not include

substations that are used as a point of delivery. An example of transmission facilities included in the Bulk System is the 240 kV lines between Calgary and Edmonton.

**Local System:** The local system delivers electric energy from the bulk system to a local area and 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 required for, and is normally designed to be robust enough to provide continuous service in the event that there is an outage at one point of delivery, and service must be provided through neighboring points of delivery via the underlying distribution system (25 kV and below). 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.

**Point of Delivery (POD):** 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).

### **Other Definitions of Transmission System Components**

**System Facilities:** System facilities are used to provide service to a large number of end use customers. The costs of system facilities are rolled into the total cost of transmission, and are recovered within general rates. System facilities are included in all three transmission system functions; bulk, local and point of delivery (where the transmission point of delivery provides service to a large number of end use customers).

**Customer Related Facilities:** Customer related facilities are transmission facilities that are constructed at the request of a customer for the purpose of interconnecting the customers' facilities to the Alberta interconnected electric system. The customer related facilities comprise of a basic, standard supply configuration and are used as the basis to determine customer related costs for application of the investment policy to determine any customer contribution payable.

In the event that construction of customer related facilities provides an opportunity for enhancements to system facilities, customer related facilities may be upgraded for the benefit of the system, and these incremental costs are deemed "system", and are rolled into the total transmission costs. In the event that the customer requests service beyond the standard level of

service, the incremental costs are deemed optional supply facilities, and are recovered from the customer in the form of a contribution.

Customer related facilities are included in all three transmission system functions; bulk, local and point of delivery. Customer related facilities may be reclassified as system facilities when new customers are added, and served by customer related facilities.

These definitions of transmission system components were rejected as the basis of a function for a Cost Causation Study because these definitions do not provide the basis of a function, there is no simple way of correlating facilities to these definitions, and the facilities within these definitions may move from one definition to another over time as the system evolves.

### **Distinctions Used by Planners to Differentiate between Transmission Functions**

**Complexity in Planning:** The bulk system is the most complex system to plan in that many contingencies and criteria must be considered. The local system is less complex, and the point of delivery is least complex.

**Impact of Failure:** The impact of a failure of the bulk system has wide reaching implications, and has the highest likelihood of cascading outages. The failure of the local system will typically impact a small number of points of delivery, or a small geographic area and has a lower likelihood of cascading outages. A failure of point of delivery facilities impacts only one point of delivery substation and has the lowest likelihood of cascading outages.

**Diversity of Load:** The bulk system is planned on the basis of a large number of diverse loads (highest amount of diversity) as well as the forecast production level and location of generation. The local system is planned to meet the coincident load of a small number of diverse loads and the point of delivery is planned to meet the load of one point of delivery substation (no diversity).

### **Application of the Definitions of Transmission Functions**

The definitions of transmission functions do not allow for definitive functionalization of all transmission facilities. The distinction between Point of Delivery facilities and other functions is well defined, but the distinction between Bulk and Local requires further definition. Some facilities clearly fit into one function or the other, while other facilities do not.

There are two possible approaches to functionalization; one being to develop hard rules to define functions, and then apply the rules without judgment, and the second being to allow the use of judgment to functionalize facilities. The latter approach was rejected because results are not repeatable, and the process could easily become contentious. The first approach was chosen to allow simple and repeatable use of the rules to functionalize property. Three different sets of rules were developed to objectively functionalize transmission facilities.

#### **4.2. Option 1 – Functions Defined by Voltage Level**

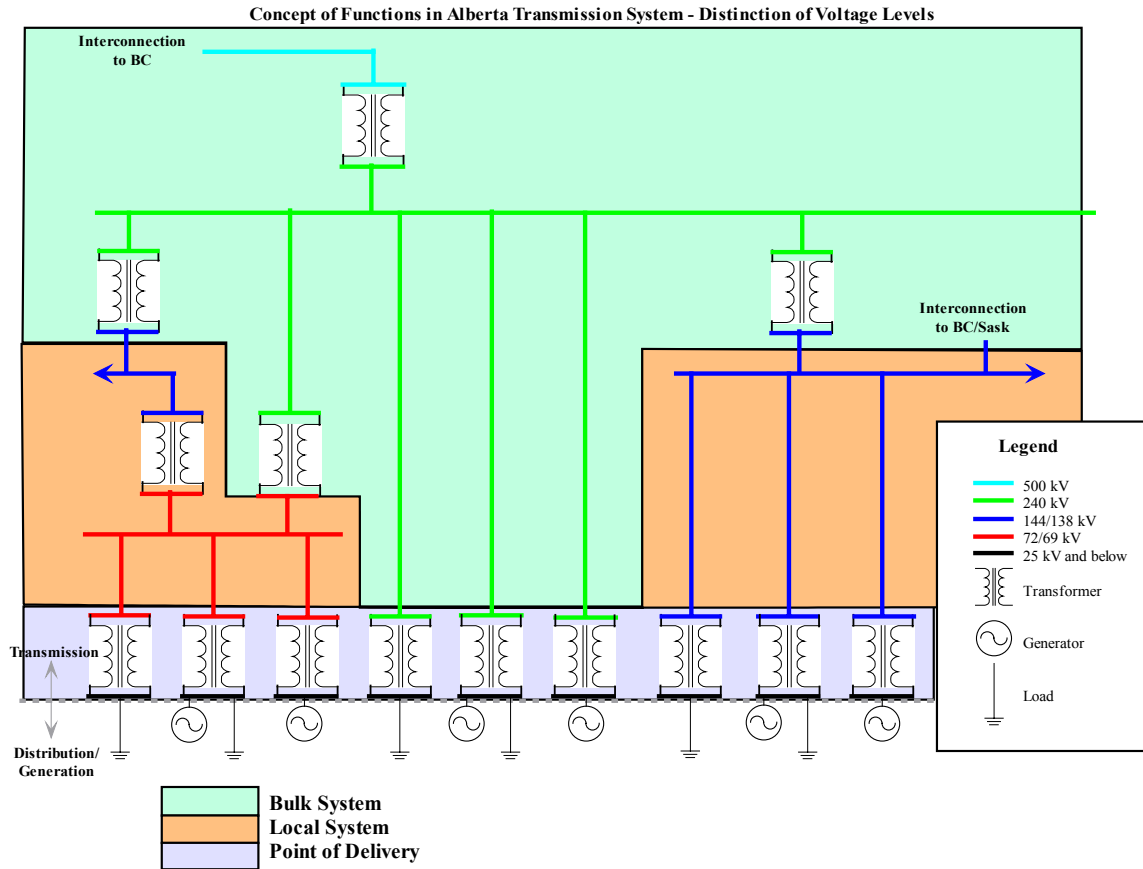
The first view of separating transmission facilities into functions is based on voltage level. The 500 kV and 240 kV facilities are considered Bulk System on the basis that these systems carry large amounts of power over long distances. The 138/144 kV and 69/72 kV and lower voltage looped transmission lines are considered Local System. Radial lines serving one POD, and POD substations are considered Point of Delivery. Point of supply substations and substations with the secondary voltage at 138 kV or higher are considered Bulk System. A substation where the primary voltage is 138/144 kV, and the secondary voltage is 69/72 kV is considered Local System.

Advantages of using voltage levels to define functions include simplicity, and objectivity and it appears to represent the functions of a transmission system in Alberta today, particularly in large urban areas. Transmission planners generally functionalize transmission facilities on the basis of voltage level, and yet planners recognize that there are exceptions.

Disadvantages of using voltage levels to define functions include the fact that voltage is a technical parameter and it does not dictate function. Also, functions by voltage level change over time. The 138 kV system that was constructed in Alberta half a century ago, would have been considered a Bulk System at that time. Over time, these lines have had points of delivery inserted in the line, and today, these lines perform the function of local system. Voltage levels indicate historic practices and may be energized at levels lower than their design voltage. Voltage levels may not provide an accurate view of function in remote and rural areas where a facility may perform both functions of Bulk and Local system.

This view of functions is consistent with the transmission systems in large urban areas where there is an overlying transmission system consisting of 240 kV circuits that may be considered Bulk and where the underlying 138/144 kV systems distributes electricity to several local POD's and is considered Local. The Point of Delivery includes all radial line and substation costs where there is a point of delivery substation. The following figure illustrates how the functions overlay on the figure of the electric system by voltage level.

Figure 2 Function by Voltage Level



Assumptions and Observations:

- Substations are functionalized as complete units even though substations span more than one voltage level and its corresponding function. Cost data is available only on the basis of a complete substation. Substations with a secondary voltage of 138 kV and up are Bulk System and substations with a secondary voltage of 25 kV and below are considered POD.
- All radial lines serving one point of delivery are functionalized as POD.
- Voltage level does not appear to represent function well in remote and rural areas where there is only one transmission voltage level.
- Voltage level does appear to represent function well in the urban areas of Calgary and Edmonton.
- Voltage levels are primarily determined at the time that the facility is planned, and voltage levels are rarely changed through the life of the facility. As the system evolves,

the function of a facility may change, but the voltage level does not change, and therefore the functionalization for some facilities may not be accurate.

Table 3 shows the percentage of the total transmission net book value, for each TFO that falls into each function when the functions are defined by voltage level. Cost data from EPCOR and ENMAX did not provide enough detail to functionalize by voltage level and was functionalized on the basis of the available data.

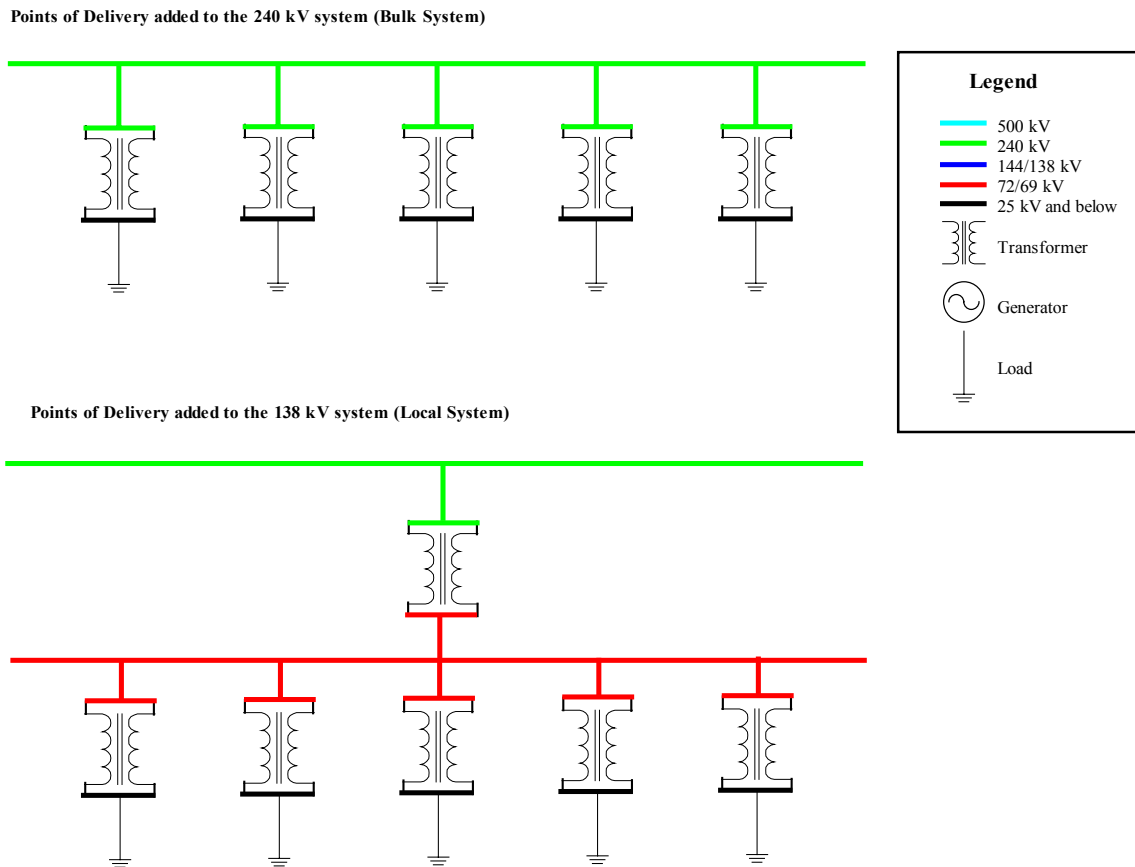
**Table 3 Functionalization of Transmission Property – by Voltage Level**

TFO	Bulk System	Local System	POD
AltaLink	48.8%	15.4%	35.8%
Atco Electric	49.9%	21.6%	28.6%
EPCOR/ENMAX	10.7%	21.0%	68.3%
Sum of 4 TFO's	42.7%	18.8%	38.6%

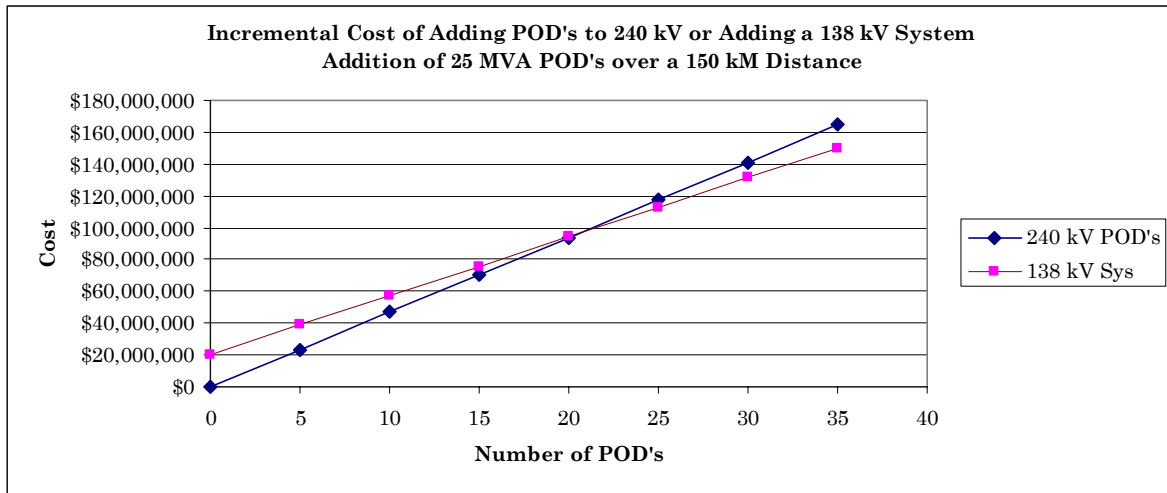
### 4.3. Option 2 – Functions Defined by Economics

Another method of determining the function of transmission property is to consider the economics that would differentiate a Bulk System from a Local System. The Bulk System is optimal for delivering large volumes of electricity over long distances, but is not an optimal system for the addition of numerous points of delivery, while the Local System is vice versa. This method assumes that a high voltage line is constructed through an area, and then as the area is developed, additional points of delivery are added to the line.

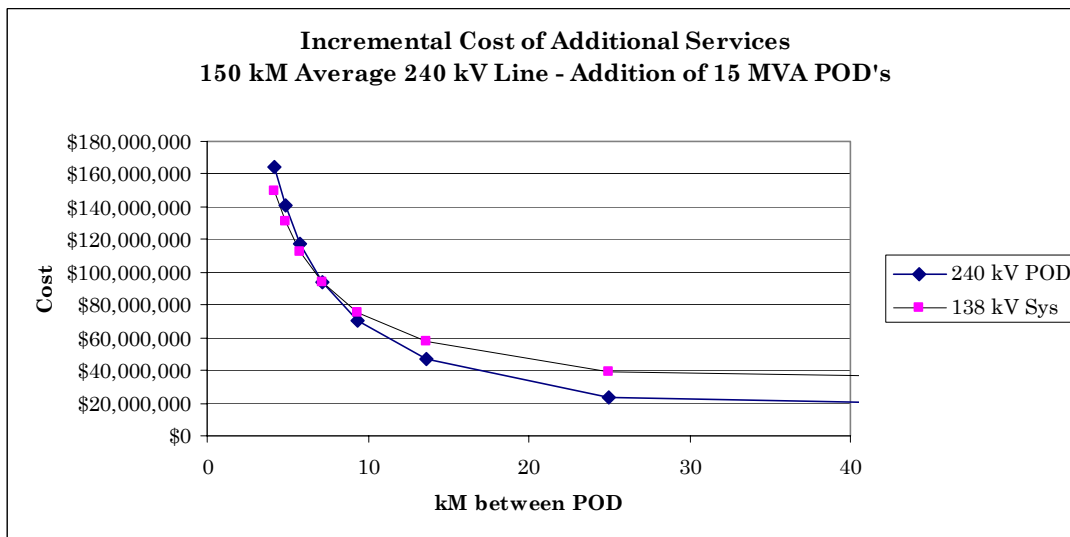
A hypothetical high voltage line (240 kV with a length of 150 km – equal to the length of a line between Calgary and Red Deer, or Red Deer to Edmonton) was developed as the base case, and then points of delivery (240/25 kV) were added to the line. Another alternative is to add a 240/138 kV transmission substation, and connect the additional points of delivery to the 138 kV Local System. These two alternatives are illustrated below.



The cost of adding points of delivery is a function of the number of points of delivery being added. For a small number of points of delivery added to a 150 km line, it is less expensive to connect to the 240 kV system than to build an underlying 138 kV system. If there are a large number of points of delivery being added, it is less expensive to add a 138 kV system, and connect the POD's to the 138 kV line. The following chart shows this relationship.



The same data is plotted on the basis of distance between POD's.



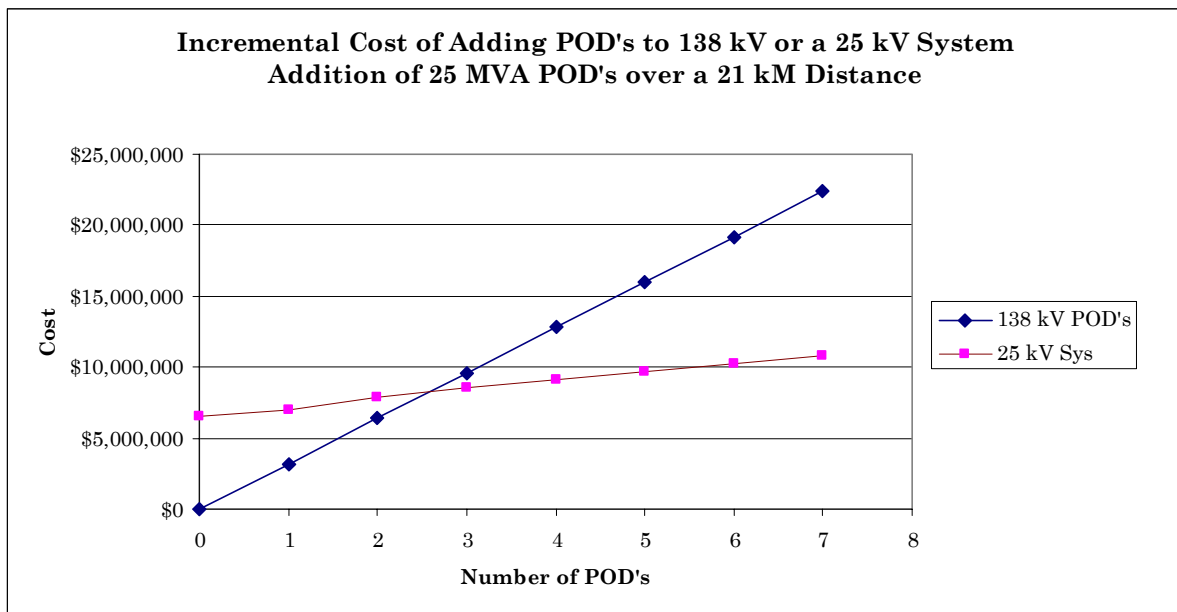
As shown in the chart above, a 240 kV line providing a Bulk System function may be used to connect points of delivery when the distance between points of delivery is greater than 6 km. Lines shorter than 6 km are an indicator that the 240 kV line is performing the function of a Local System. This line length forms the basis for functionalizing the 240 kV lines, with lines

over 6 kM being functionalized as Bulk System, and shorter lines being functionalized as Local System.

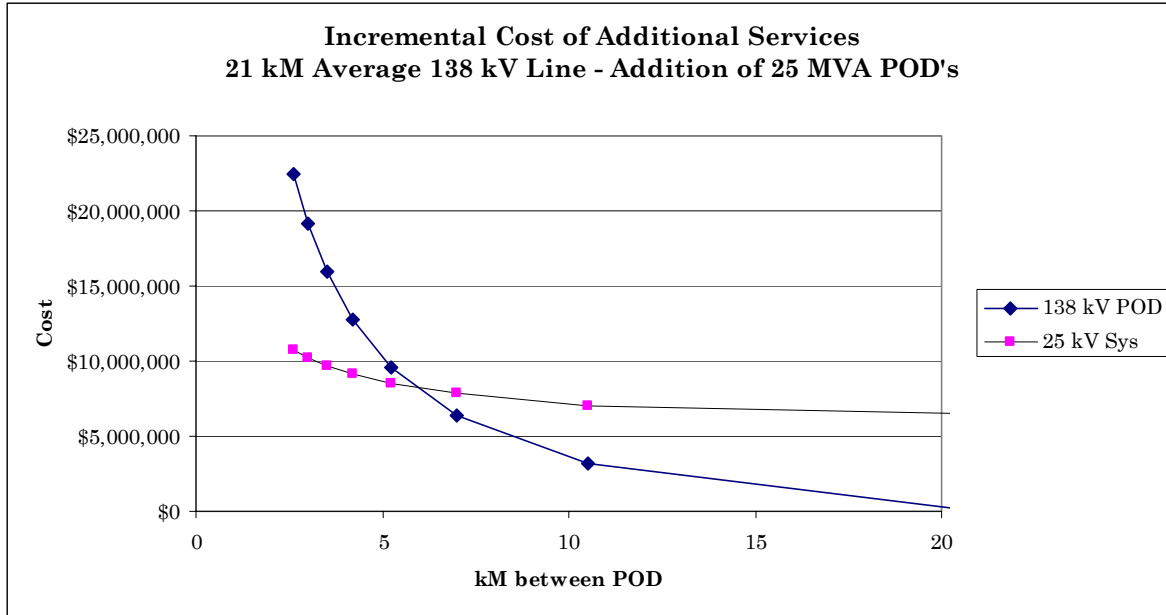
The same method was used to functionalize 138 kV lines. A hypothetical high voltage line (138 kV with a length of 21 kM – equal to the average length of 138 kV lines in Alberta) was developed as the base case, and then points of delivery (138/25 kV) were added to the line. The other alternative is to add a large 138/25 kV substation, and connect the additional points of delivery to a 25 kV Local System.

A 138 kV line longer than 6 kM is considered to have a purpose of bulk transportation while a line shorter than 6 kM is considered to have a purpose of distributing power in the local system. Therefore, the line length forms the basis for functionalizing the 138 kV lines, with lines over 6 kM being functionalized as Bulk System and shorter lines are functionalized as Local System.

The following chart shows the cost of adding points of delivery to a 138 kV line, and the cost of adding a major step down substation in the middle of the line, and serving points of delivery from the lower voltage.



The same data is plotted in the following chart indicating the distance between points of delivery.



#### Assumptions and Observations:

- Substations are functionalized as complete units with substations with a secondary voltage of 138 kV and up are Bulk System and substations with a secondary voltage of 25 kV and below are considered POD.
- All radial lines are functionalized as POD.
- This method is based on the assumption that a Bulk System line exists in an area, and that subsequent development results in a Local System.
- This method provides an objective and repeatable means of functionalizing transmission facilities.
- This method is academic and theoretical and may not reflect functions of some facilities because of the way in which the system evolved. For example, if a Bulk line crosses an area with gradual development, the lowest cost approach at each point of delivery is to add another high voltage point of delivery, rather than the development of one optimally sized system. Therefore, this method will be biased to functionalizing property to Bulk System.

This method of economics is distilled into functionalization by line length where long lines are functionalized as Bulk, and short lines are functionalized as Local, regardless of the voltage or capacity of the line (with the exception of 69/72 kV lines that were functionalized as Local).

Table 4 shows the percentage of the total transmission property, for each TFO that falls into each function when the functions are defined by economics as described above. Cost data from EPCOR and ENMAX did not provide enough detail to functionalize by economics and was functionalized on the basis of the available data.

**Table 4 Functionalization of Transmission Property – Economics**

TFO	Bulk System	Local System	POD
AltaLink	60.5%	3.7%	35.8%
Atco Electric	60.5%	10.9%	28.6%
EPCOR/ENMAX	10.7%	21.0%	68.3%
Sum of 4 TFO's	52.0%	9.5%	38.6%

#### 4.4. Option 3 – Functions Defined by MW-kM

A third method of determining the function of transmission property was developed. The third method is based on quantifying the definition of the Bulk System where the Bulk System is defined as delivering a large volume of electric energy over a long distance. The distinction between Bulk System and Local System is made on the basis of volume and distance, or MW-kM. Table 5 shows the statistics for the Alberta transmission system, as forecast to function during the peak system load for the winter peak of 2004/2005.

**Table 5 Existing System Statistics – MW-kM**

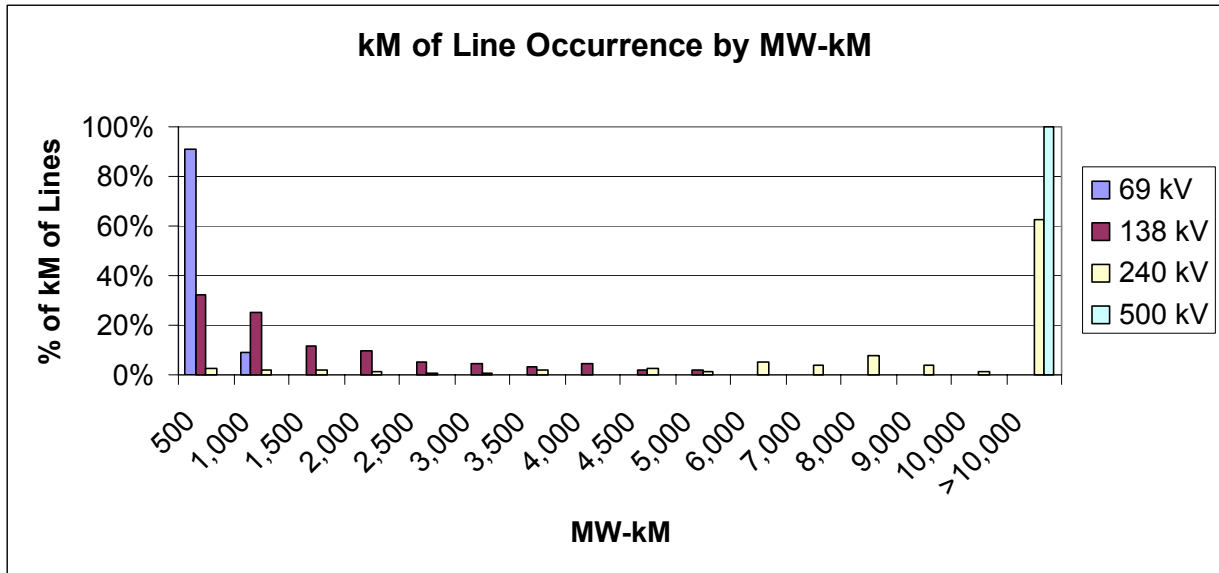
Line Statistics - MW-kM						
Line Voltage	Total kM of Line (kM)	Number of Lines	Average Line Len (kM)	Average MW-kM (MW-kM)	Total MW-kM (MW-kM)	% of Tot MW-kM
69/72 kV	2,656	236	11	76	17,969	1%
138/144 kV	11,196	536	21	563	301,681	22%
240 kV	6,762	112	60	8,916	998,575	73%
500 kV	319	3	106	17,783	53,349	4%
Total	20,932	887		1,546	1,371,573	100%

The winter peak was chosen as the point to view the system because all transmission elements are in service, and generation is dispatched on a forecast basis, thereby eliminating the effects of forced and maintenance outages.

The first approach to quantifying a MW-kM level that distinguishes Bulk System from Local System is based on observing the existing system. When dividing the total MW-kM by the total kM of transmission line in Alberta, the average is shown as 1,546 MW-kM and this could be one basis for differentiating between Bulk and Local system. As well, the average MW-kM for 138 kV lines (which are normally considered Local System) is 560, and the average MW-kM for 240 kV lines (which are normally considered Bulk System) is 8,900. The range of 600 to 9,000 MW-kM will establish the bounds to distinguish between Bulk and Local Systems. The 138 and 240 kV circuits carry 95% of the MW-kM in Alberta, and these two voltage levels are reviewed further. The 69 kV circuits will all be considered Local while the 500 kV circuit will be considered Bulk.

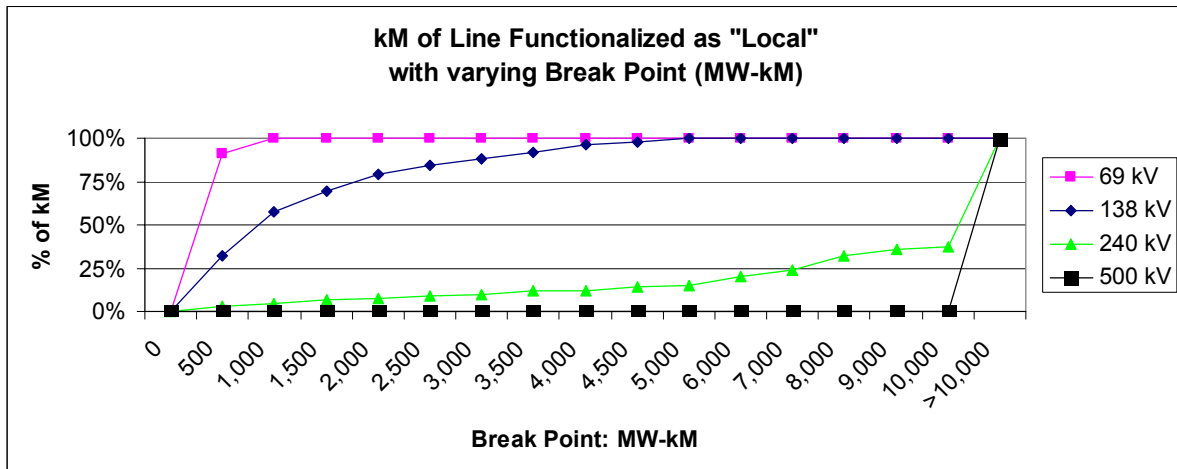
The following chart shows the frequency of occurrence of lines by voltage and by MW-kM.

Figure 3 MW-kM by Voltage



The following chart shows the cumulative effect of functionalizing line by varying the breakpoint in MW-kM to distinguish Bulk and Local

Figure 4 Effect of Varying Breakpoint in MW-kM



Another view of lines in Alberta is the occurrence of MW-kM versus line loading as shown in the following two charts. The data points at 0 MW-kM are not actual data points and result from Excel plotting zero in place of a blank cell.

Figure 5 Occurrences of Lines and Associated MW-kM

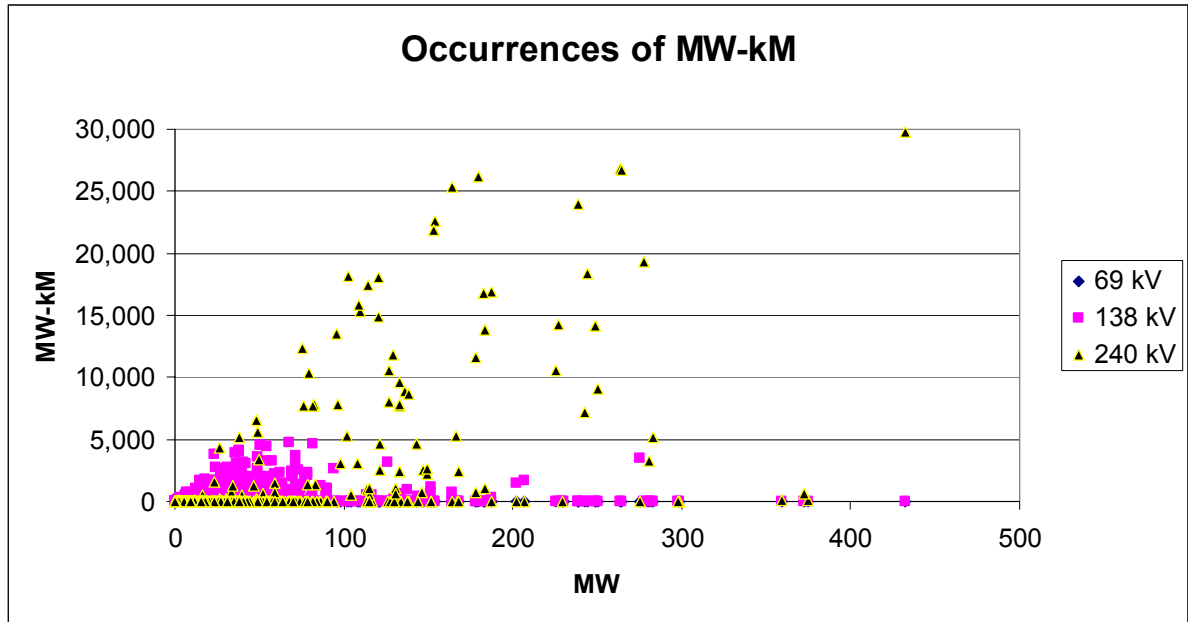
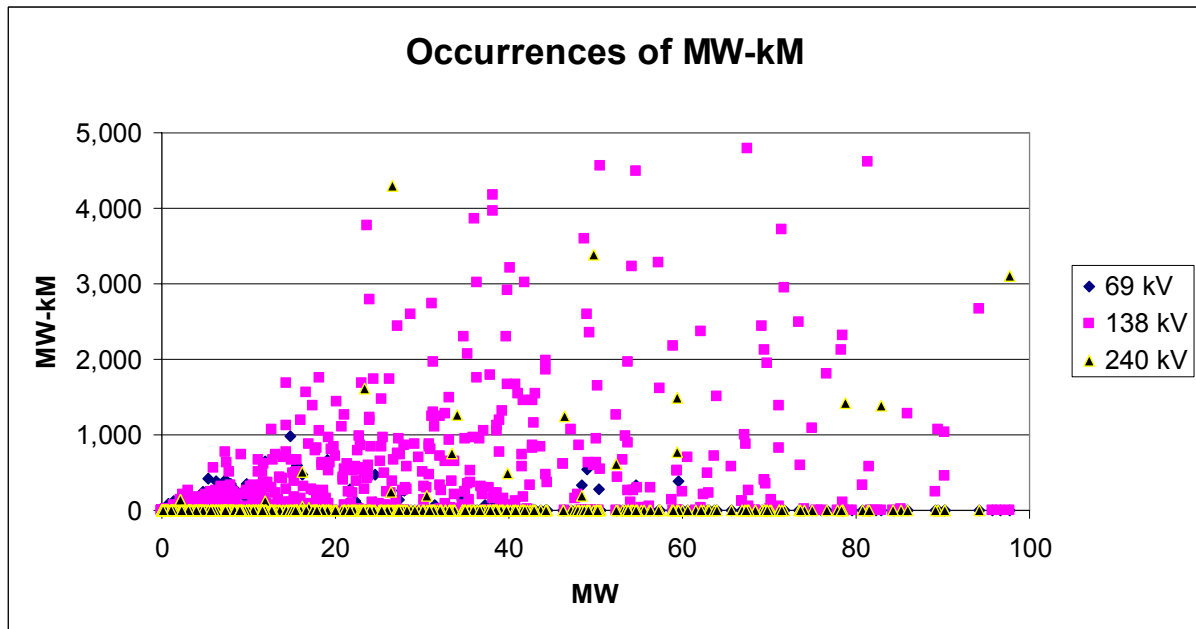


Figure 6 Occurrences of Lines and Associated MW-kM with expanded Scale



Some planners consider that some 138 kV lines perform a Bulk function and on that basis, the distinction between Bulk and Local must be less than 5,000 MW-kM. Some planners consider that some 240 kV circuits perform a local function and on that basis, the distinction between Bulk and Local must be greater than 1,000 MW-kM. This observation provides a narrower range of 1,000 to 5,000 MW-kM as the distinction between Bulk and Local systems.

The level of 3,000 MW-kM was chosen as the distinction between Bulk and Local on the basis that is a midpoint in the range.

As with other means of functionalization, the distinguishing level may change over time, and will have to be recalibrated.

**Assumptions and Observations:**

- Line loading data is obtained from a forecast system peak load flow model with all elements in service (2004/2005 winter peak load case).
- Substations are functionalized as complete units with substations with a secondary voltage of 138 kV and up are Bulk System and substations with a secondary voltage of 25 kV and below are considered POD.
- All radial lines serving load are functionalized as POD.
- This method provides an objective and repeatable means of functionalizing transmission facilities.
- This method will functionalize a line as Local System if it is lightly loaded at the time of peak system load, even though the line may be heavily loaded during other periods.
- The MW-kM method recognizes changes in facility functions as the system evolves.

The line information from the 2004/2005 Winter Peak case does not match precisely with the cost information provided by the TFO's, and therefore instead of using net book value by line, line length is used as a proxy for property.

Table 6 shows the percentage of the total transmission property that falls into each function when the functions are defined by MW-kM. Cost data from EPCOR and ENMAX did not contain enough detail to functionalize by MW-kM.

**Table 6 Functionalization of Transmission – MW-kM (3,000 MW-kM Distinction)**

TFO	Bulk System	Local System	POD
AltaLink	48.9%	15.4%	35.8%
Atco Electric	49.5%	21.9%	28.6%
EPCOR/ENMAX	10.7%	21.0%	68.3%
Sum of 4 TFO's	42.6%	18.9%	38.6%

The following tables show the variation or sensitivity in functionalization when using a range of MW-kM to define functions.

**Table 7 Functionalization of Transmission – (1,000 MW-kM Distinction)**

TFO	Bulk System	Local System	POD
AltaLink	53.6%	10.7%	35.8%
Atco Electric	55.7%	15.8%	28.6%
EPCOR/ENMAX	10.7%	21.0%	68.3%
Sum of 4 TFO's	47.0%	14.4%	38.6%

**Table 8 Functionalization of Transmission – (9,000 MW-kM Distinction)**

TFO	Bulk System	Local System	POD
AltaLink	43.6%	20.7%	35.8%
Atco Electric	41.5%	29.9%	28.6%
EPCOR/ENMAX	10.7%	21.0%	68.3%
Sum of 4 TFO's	37.1%	24.3%	38.6%

#### 4.5. Summary and Recommendation for Functionalization

The three options provide different views of how transmission property can be functionalized in an objective way. Subjective functionalization was rejected because the results were not repeatable, and there was no assurance that a reasonable group of experts could come to an agreement with respect to functionalization of transmission property.

The three methods provide results that are somewhat similar. The POD definition does not change and the functionalization of POD property remains stable. The variation occurs as to the distinction between Bulk System and Local System.

All three methods have strengths and weaknesses. We consider that the MW-kM method is the strongest because it most closely aligns the purpose of transmission facilities to their functional category. Since this type of study is relatively new, we recommend that the functionalization be based on the average results of the three methods.

**Table 9 Recommendation as to Functionalization of Costs – Transmission Property**

TFO	Bulk System	Local System	POD
Voltage Level	42.7%	18.8%	38.6%
Economics	52.0%	9.5%	38.6%
MW-kM	42.6%	18.9%	38.6%
<b>Recommendation</b>	<b>45.7%</b>	<b>15.7%</b>	<b>38.6%</b>

## 5. Classification

Classification considers the costs associated with each function, and classifies them as demand, energy or customer related. Prior to industry restructuring in 1996, transmission costs were subject to EEMA. The costs associated with transmission were traditionally classified as demand related and debate focused on weighting by one annual coincident peak, or some weighting to peak demand in months other than the annual peak (ie 1 CP, 3W/9NW). The timing associated with the demand will also be reviewed.

The cost of the POD function will be classified as customer (POD), demand and energy related. The cost of the Bulk and Local function will be classified as demand and energy related.

Generally, transmission facilities at the point of the customer interconnection are sized to meet the customer peak (non coincident peak or NCP), and the further you go back into the system, the system is designed to meet the load coincident to the system peak load (CP), or more correctly, the load coincident to the system load at the time of maximum stress on the system (CLMS).

While transmission planning models consider one point in time, transmission planning criteria are based on experience and judgment to ensure reliable operations year round, and planners will optimize conductor size in order to minimize the total cost of wires and losses. The transmission planning process is often used as justification for classification of all wires costs by demand, because transmission planners consider demand under various scenarios. In the event that transmission planning criteria are violated, the transmission system is upgraded to accommodate the forecast demand. However, transmission planning criteria are based on experience and judgment, and therefore, it is too simplistic to classify transmission costs as completely demand related.

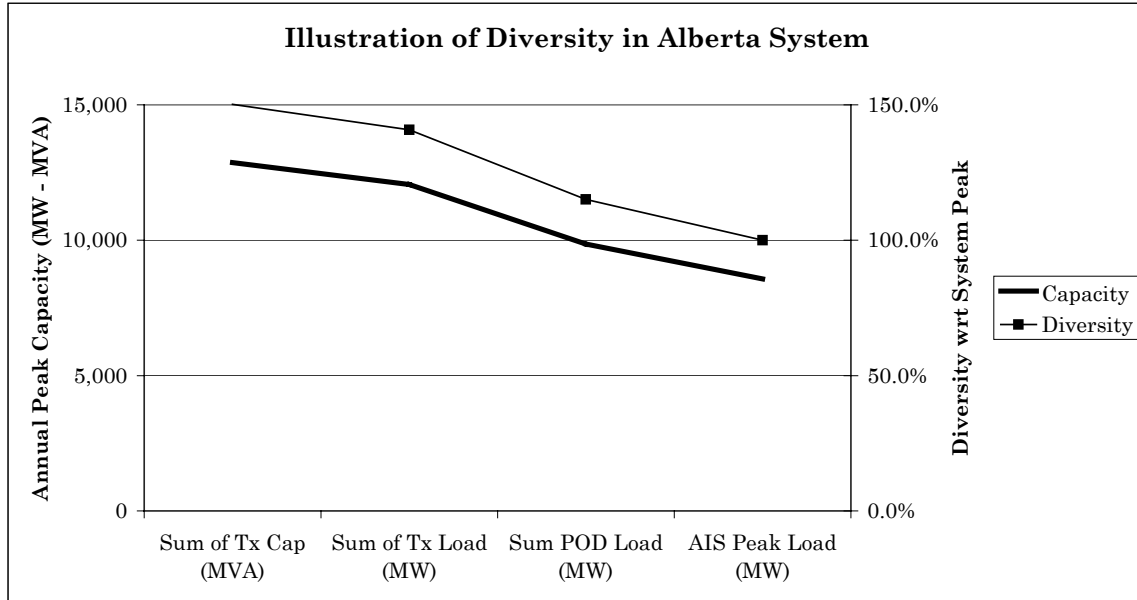
Two approaches are used to classify the costs associated with the transmission functions. These approaches are the zero intercept approach, and the minimum system approach. These approaches have not been widely used in the case of transmission systems but have been adapted for use on the transmission system based on their use in distribution systems. Transmission systems have similarities to distribution systems with respect to the fixed nature of wires costs.

The zero intercept approach is used to determine customer related, or POD related costs, and the remaining costs are classified as demand and energy on the basis of the minimum system approach. The zero intercept approach is used only for the POD function because there is a direct correlation between the POD facilities and the customer.

The minimum system approach is used for the Local and Bulk functions to determine demand and energy related costs. The minimum system is based on the smallest standard construction that is currently installed as the base cost and using the optimized standard construction as the total cost. The minimum system cost is considered demand related, instead of customer related as it is used in distribution systems, because the Bulk and Local systems are designed primarily to meet the total load, and design is relatively independent of the number of customers. The additional cost of upgrading the design to optimize the system (optimum from a perspective of minimization of the total cost of capital and energy losses) is considered energy related because it is the transportation of additional energy that drives this cost. While the additional costs are incurred to reduce energy losses, the costs are fixed capital costs.

Demand related costs have additional complexity. While demand related costs apply to the maximum demand at a POD (NCP), the demand related costs further back in the system must take into account diversity. The diversity of load in Alberta is demonstrated in Figure 7. The peak system load, or CP in 2003 was 8,570 MW, while the sum of loads at the transmission points of delivery was 9,860 MW (sum of NCP's), or 15% higher. The two additional points in the figure include the sum of loads measured on each transformer measured in MW (Sum of Tx Load), and the sum of transformer capacities in MVA (Sum of Tx Cap).

**Figure 7 Illustration of Diversity on Alberta Transmission System**



Demand related costs are based on the minimum system, based on the point in time when the system is most severely stressed. Each function may be stressed at different times. Further, different points on the bulk system may be most severely stressed at different points in time.

**5.1. Bulk System Costs**

The Bulk System is defined as transmission facilities that deliver bulk electric energy over long distances. The Bulk System is planned according to deterministic transmission planning criteria that are inherently based on demand. The nature of a transmission facility is such that the facility is sized to meet the forecast demand, and a conductor optimization study is typically performed to determine the optimum conductor size to optimize losses. The issues reviewed in this section will include the determination of the portion of costs related to demand, and to energy, as well as a review of the forecast demand that drives the need for new transmission facilities.

**Forecast Demand that Drives the Need for New Transmission Facilities**

The time of system peak from a generation perspective is different than the time of system peak from a transmission perspective because the bulk transmission system peak load occurs at different times of the year, for different areas of the system. A review of 428 transmission points of delivery showed that over the past year, 237 substations (55%) experienced peak load in the

winter (December through February). The remaining points of delivery peak in a season other than winter.

**Table 10 Season of Peak Load by POD**

Transmission Peak Season		
	POD's	Percent
Winter	237	55%
Summer	159	37%
Other	<u>32</u>	<u>7%</u>
Total	428	100%

An additional complicating factor is that thermal capacity ratings of electric equipment are lowest during the summer. The transmission planners can not consider the peak forecast demand only and assume that this case will be the most severe test of the transmission system.

A further additional complicating factor is that the time of maximum system stress on the bulk system does not coincide with peak load conditions. The time of maximum stress on the Bulk System is typically during light load periods and results from the combination of little or no import from BC to support the southern load, a condition when gas fired generation in the Calgary area is dispatched down, and base load coal fired facilities west of Edmonton are dispatched to full load. The timing of these occurrences cannot be accurately predicted.

The transmission system was observed to determine the conditions that lead to maximum stress on the Bulk System. Data was obtained from the Need Application for the Edmonton-Calgary 500 kV Transmission Development Need Application. Two parts of the Bulk System were observed, namely the north of Calgary path (NOC), and the south of Keephills path (SOK). The 2003, and 2005 Cases were studied, and the time and magnitude of maximum stress on a path is shown in the following Table and Figure.

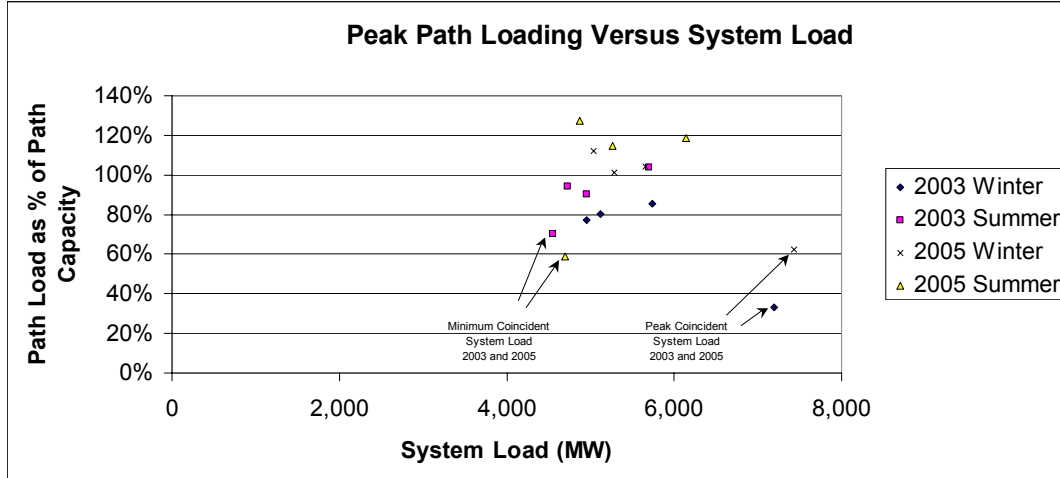
**Table 11 Maximum Stress on Bulk System Paths**

	Summer						Winter					
	Capacity (MW)	Peak Load (MW)	Load as % of Cap	Time of Peak	Total POD Load	% of Annual Peak Load	Capacity (MW)	Peak Load (MW)	Load as % of Cap	Time of Peak	POD Load (MW)	% of Annual Peak Load
2003 Case												
NOC Path	1,330.0	1,381.9	103.9%	Jul-30 8:00	5,694.7	79.1%	1,560.0	1,332.7	85.4%	Jan-18 11:00	5,741.9	79.8%
SOK Path	1,880.0	1,770.4	94.2%	Sep-13 5:00	4,731.6	65.7%	2,070.0	1,663.3	80.4%	Jan-17 2:00	5,118.9	71.1%
Combined	3,210.0	2,904.4	90.5%	Sep-13 8:00	4,959.7	68.9%	3,630.0	2,806.6	77.3%	Dec-15 5:00	4,954.4	68.8%
Annual Min CL	3,210.0	2,248.2	70.0%	Jun-15 7:00	4,552.5	63.3%						
Annual - CP							3,630.0	1,204.3	33.2%	Dec-3 18:00	7,196.7	100.0%
2005 Case												
NOC Path	1,330.0	1,578.6	118.7%	Jul-12 11:00	6,139.2	82.6%	1,560.0	1,629.4	104.5%	Nov-3 0:00	5,652.8	76.1%
SOK Path	1,880.0	2,398.2	127.6%	Sep-13 5:00	4,876.7	65.6%	2,070.0	2,319.0	112.0%	Mar-21 2:00	5,033.5	67.8%
Combined	3,210.0	3,677.7	114.6%	Jul-13 9:00	5,265.9	70.9%	3,630.0	3,671.0	101.1%	Jan-17 2:00	5,280.0	71.1%
Annual Min CL	3,210.0	1,889.1	58.8%	Jun-15 7:00	4,693.4	63.2%						
Annual - CP							3,630.0	2,264.4	62.4%	Dec-3 18:00	7,429.0	100.0%

Notes:  
 Load Profile is constant, and adjusted for forecast.  
 Increase results from addition of Genessee and addition of Fort McMurray generators.  
 CL: Coincident Load, CP: Coincident Peak

The following Figure shows the relationship between Path Load and System Load at the time of maximum stress on the Bulk System.

**Figure 8 Maximum Stress on Bulk System Paths**



Based on the data in Table 11, and the Chart in Figure 8, it is apparent that other factors, in addition to coincident peak load, contribute to maximum stress on the Bulk System. The magnitude of the maximum stress on the Bulk System drives the need for new transmission facilities and is the cost driver, and the coincident system peak load currently does not drive the need for new Bulk System facilities and therefore, is not a cost driver.

Factors that cause the peak stress on the Bulk System to occur at times other than the peak coincident system load include:

- Location of generation,
- Dispatch of generation,
- Imports and exports.

Notwithstanding the fact that the time of peak stress on the Bulk System does not coincide with the time of peak system load, the Bulk System is designed to meet the peak stress when the peak stress occurs.

The time of peak stress on the Bulk System for the NOC path and the SOK path occur during the morning in July and September in 2003 and 2005. The point in time of peak stress on the Bulk System is not intuitively obvious because there are many factors at play.

### Determination of the Portion of Costs related to Demand, and to Energy

A simple minimum system approach was taken to differentiate demand related and energy related costs for the Bulk System. The approach taken was on the basis of a 240 kV line built to the minimum standards currently in place, which is a circuit with bundled 477 kcmil conductor. A bundle of two conductors of 477 kcmil conductor is the smallest conductor that complies with all applicable codes. The 240 kV line is then optimized with respect to capital and line loss costs. The optimized system cost is the average of a 240 kV circuit with bundled 795 and 1590. The demand related costs are those costs associated with the minimum sized conductor, and the energy related costs are those costs associated with upgrading the line to an optimal system.

**Table 12 Classification of Bulk Transmission Lines – Minimum System**

240 kV Line (Bulk System) Base and Optimal Costs - Minimum System Approach, Cost per km					
		Cost of Conductor	Other Cost	Total Line Cost	Per Cent of Optimal Cost
Minimum System	240 kV Line - 2 X 477	\$39,642	\$110,358	\$150,000	67.7%
Lower End Optimal Line	240 kV Line - 2 X 795	\$66,552	\$121,394	\$187,946	
Upper End Optimal Line	240 kV Line - 2 x 1590	\$121,488	\$133,533	\$255,021	
Average of Optimal Line				\$221,483	
<b>Demand Related Costs</b>					<b>67.7%</b>
<b>Energy Related Costs</b>					<b>32.3%</b>

Bulk substations were also considered on a minimum system basis. For simplification, the minimum system applicable to POD substations is also used for Bulk substations as follows:

**Table 13 Classification of Bulk Substations**

Substation Cost (POD) Base and Optimal Costs - Minimum System Approach					
		Cost of Transformer	Other Cost	Total Substation Cost	Per Cent of Optimal Cost
Minimum System	Basic Transformers	\$1,200,000	\$2,500,000	\$3,700,000	98.4%
Optimized System	High Eff Transformers	\$1,260,000	\$2,500,000	\$3,760,000	
<b>Demand Related Costs</b>					<b>98.4%</b>
<b>Energy Related Costs</b>					<b>1.6%</b>

The classification for Bulk Systems is based on the weighted amount of line and substation in the Bulk System.

**Table 14 Classification of the Bulk System**

<b>Bulk System - Weighted for Lines and Substations</b>		
Line Related Bulk System Property (AltaLink and Atco Bulk (Volt Level) Lines)	322,994.25	55.0%
Substation Related Bulk System Property (AltaLink and Atco Bulk (Volt Level) Lines)	263,916.68	45.0%
Bulk Property	586,910.93	
<b>Weighted Demand Related Costs</b>		<b>81.5%</b>
<b>Weighted Energy Related Costs</b>		<b>18.5%</b>

### **Allocation of Demand Related Costs and Implications on Rate Design**

The minimum system approach results in demand related costs accounting for 80% of the total costs of the Bulk System. The demand related costs are associated with the coincident load at the time of maximum system stress (CLMS). The demand at the time of peak system stress is not a practical demand related billing parameter because customers do not generally have visibility as to the time of maximum system stress (and further, the time of peak stress will vary at different points in the system), and therefore cannot react to the price signal. The customer demand coincident to the system peak is not a practical demand related billing parameter because the demand coincident to system peak is not a cost driver.

Customer demand may have a positive or negative correlation to peak stress on the Bulk System. For example, low demand in the Edmonton area contributes to peak stress on the NOC and SOK path. While demand related costs (CLMS) consist of 80% of the total Bulk System costs, the recovery of revenue through demand charges should be lower than 80% if the billing demand is based on the customers peak demand at a time other than load coincident to the time of maximum system stress.

## 5.2. Local System Costs

The Local System is typically designed to provide uninterrupted service with the loss of any one element (transmission line, transformer, etc). The peak stress on a local system will likely occur at the time that neighboring POD’s are at or near their peak load (and based on seasonal ratings).

A simple minimum system approach was taken to differentiate demand related and energy related costs for the Local. The approach taken was on the basis of a 138 kV line built to the minimum standards currently in place. The minimum system is a 138 kV circuit with 266 kcmil conductor which is the smallest conductor used that complies with all applicable codes. The 138 kV line is optimized with respect to cost of capital and losses. The optimized system cost is the average of a 138 kV circuit with 477 and 636 kcmil conductor. The demand related costs are associated with the minimum system and the additional cost of the optimized system is classified as energy related costs.

**Table 15 Classification of Local System Lines – Minimum System**

138 kV Line (Local System) Base and Optimal Costs - Minimum System Approach, Cost per KM					
		Cost of Conductor	Other Cost	Total Line Cost	Per Cent of Optimal Cost
Minimum System	138 kV Line - 266	\$11,994	\$58,006	\$70,000	80.6%
Lower End Optimal Line	138 kV Line - 477	\$19,821	\$63,807	\$83,628	
Upper End Optimal Line	138 kV Line - 636	\$26,370	\$63,807	\$90,177	
Average of Optimal Line				\$86,902	
<b>Demand Related Costs</b>					<b>80.6%</b>
<b>Energy Related Costs</b>					<b>19.4%</b>

Local substations were also considered on a minimum system basis. For simplification, the minimum system applicable to POD substations is also used for Local substations, and the overall classification for Local Systems is based on the weighted amount of lines and substations.

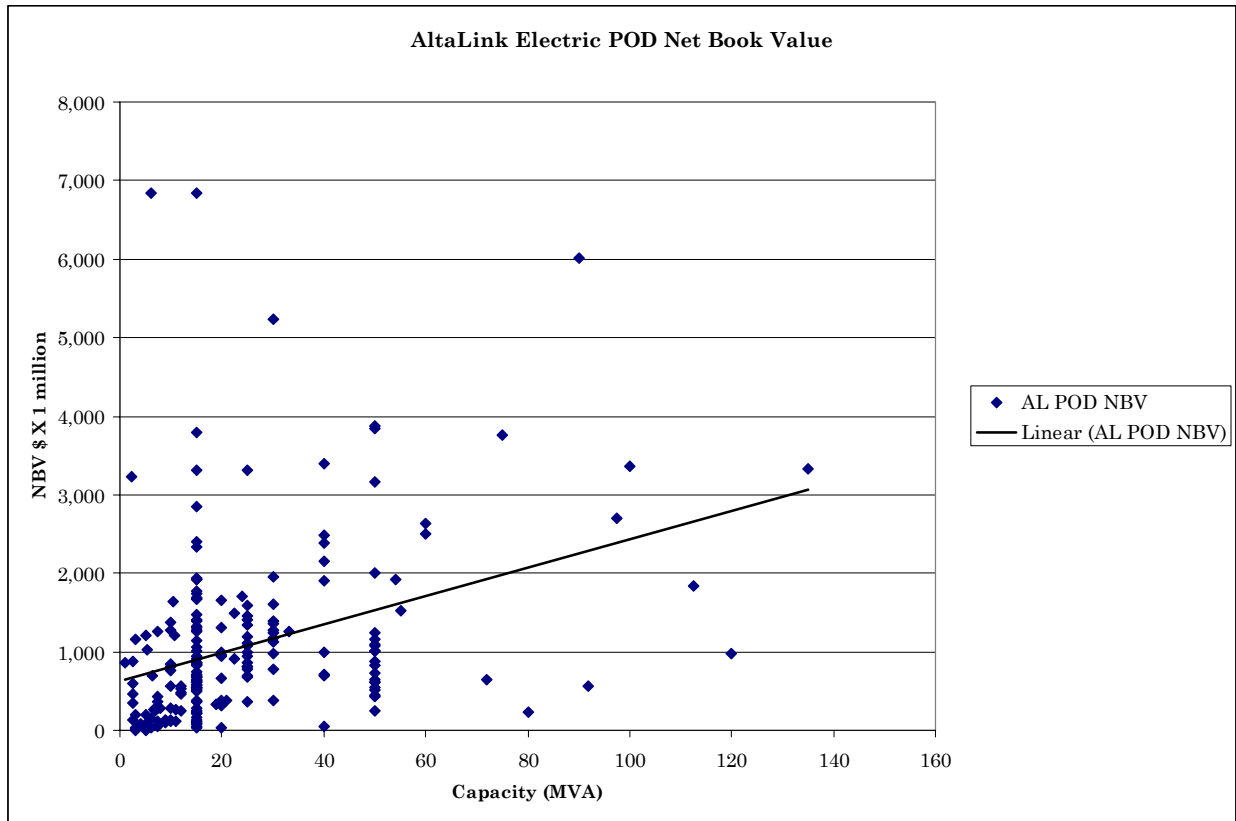
**Table 16 Classification of Local Systems – Minimum System**

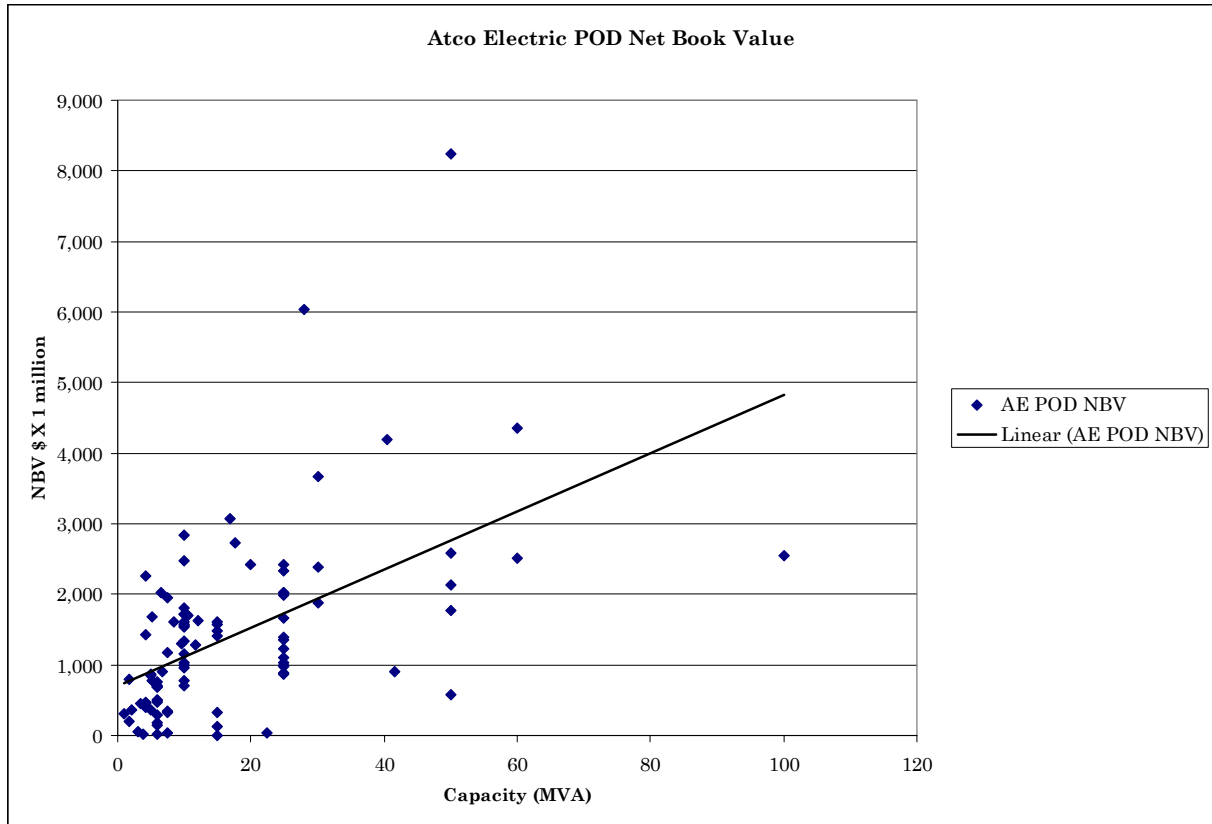
Local System - Weighted for Lines and Substations		
Line Related Local System Property (AltaLink and Atco Bulk (Volt Level) Lines)	194,529.06	88.9%
Substation Related Local System Property (AltaLink and Atco Bulk (Volt Level) Lines)	24,352.05	11.1%
Bulk Property	218,881.12	
<b>Weighted Demand Related Costs</b>		<b>82.5%</b>
<b>Weighted Energy Related Costs</b>		<b>17.5%</b>

### 5.3. Point of Delivery Costs

Planning of POD capacity is less complex than Local or Bulk systems because diversity between POD's need not be considered. POD facilities are planned and constructed to meet the forecast peak load. Cost of POD facilities were reviewed to determine customer, demand, and energy related costs.

The zero intercept cost by POD is the basis for the customer related costs. The fixed cost by POD was determined applying linear regression to the cost data provided by TFO's. The cost by substation was plotted against the substation capacity in MVA. The zero intercept for capacity was used to determine the fixed cost by POD substation.





Based on the linear regression, 50% of POD substation costs are fixed costs and the remainder varies with capacity.

**Table 17 Fixed and Capacity Substation Costs**

<b>AE and AL</b>	<b>Fixed</b>	<b>Variable</b>
<b>POD Property</b>	<b>204,680</b>	<b>159,326</b>
	<b>56%</b>	<b>44%</b>

The costs that vary with capacity in the linear regression were further reviewed on the basis of a minimum system (therefore these varying costs are broken down in to demand and energy related costs). The cost of a substation was assessed with a normal efficiency transformer, and a high efficiency transformer that may be suitable for a high load factor customer. The costs are illustrated below.

**Table 18 Minimum System - POD**

Substation Cost (POD) Base and Optimal Costs - Minimum System Approach					
		Cost of Transformation	Other Cost	Total Substation Cost	Per Cent of Optimal Cost
Minimum System	Basic Transformers	\$1,200,000	\$2,500,000	\$3,700,000	98.4%
Optimized System	High Eff Transformers	\$1,260,000	\$2,500,000	\$3,760,000	
<b>Non Energy Related Costs</b>					<b>98.4%</b>
<b>Energy Related Costs</b>					<b>1.6%</b>

On the basis of using the zero intercept method to calculate customer related costs, and using a minimum system approach to determine the classification of the remaining costs to demand and energy related costs, POD costs are classified as follows (the 50.3% of the remaining costs are prorated from the minimum system shown in Table 15):

**Table 19 Classified POD Costs**

Substation Cost (POD) - Classification of Costs				
	Customer (POD) Related Costs	Demand Related Costs	Energy Related Costs	Total
% of POD Function Property	56.2%	43.1%	0.7%	100.0%

#### 5.4. Summary and Recommendation for Classification

The classification of costs by function indicates the relative amount of transmission property in each function that is demand, energy and customer related as follows:

**Table 20 Summary of Classified Costs**

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

## 6. Wires Only – Cost of Service Summary

The purpose of this report was to functionalize and classify the cost of the transmission system in Alberta in order to address AEUB directives and to assist the AESO in rate design.

The existing rate structure for DTS customers recovers 60% of the allocated wires cost on the basis of demand, and 40% on the basis of energy.

The following table summarizes the findings.

**Table 21 Summary of Functionalization Results and Recommendation**

TFO	Bulk System	Local System	POD
Voltage Level	42.7%	18.8%	38.6%
Economics	52.0%	9.5%	38.6%
MW-kM	42.6%	18.9%	38.6%
<b>Recommendation</b>	<b>45.7%</b>	<b>15.7%</b>	<b>38.6%</b>

The next step is to use transmission property as the basis for revenue requirement.

Some wires costs are recovered from regulated generating units, and this property was functionalized as Bulk System, and therefore revenue from RGUCC is deducted from the Bulk System revenue requirement as follows.

**Table 22 Conversion of Property to Annual Revenue Requirement**

Direct Conversion of Function NBV Property to Rev Req - 2003				
	Bulk System	Local System	POD	Rev Req
Revenue Requirement	175,207	60,209	147,784	383,200
Less RGUCC (2003)	30,598			30,598
<b>Rev Req from DTS</b>	<b>144,609</b>	<b>60,209</b>	<b>147,784</b>	<b>352,602</b>

The classification of costs is applied to the revenue requirement by function to determine the revenue requirement associated with each function and class of cost.

**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%
POD/Cust			56.2%

The 2003 Revenue Requirement functionalized and classified is shown below.

**Table 24 Conversion of Classified Costs to Annual Revenue Requirement**

Classification based on Pure Costs						
Pure Cost Based	Revenue Requirement	Bulk System	Local System	POD	Class Rev Req % of Rev Req	
Demand Related Cost	Demand (CLMS-NCP)	117,886	49,695	63,653	231,234	65.6%
Energy Related Cost	Energy	26,723	10,514	1,032	38,270	10.9%
POD Related Cost	POD/Cust	0	0	83,098	83,098	23.6%
	Totals	144,609	60,209	147,784	352,602	100.0%

**Implications on Rate Design**

Table 24 addresses classified costs on the basis of demand at the point of peak system stress (CLMS). Since this demand parameter may be impractical to bill, peak customer demand may be used. As noted in Section 5.1, demand related cost recovery should be lower than the 80% classification of costs on the basis of demand to account for the difference in timing of the peak demands.

## 7. Board Directives

This report addresses issues raised in several AEUB Directives to the AESO.

### 2000-1 Directives

22. The Board directs EAL to continually refine the transmission cost allocation in accordance with the framework established in this Decision and to use such refined cost of service studies to support proposed tariffs in future GTAs. (Section 8 )
  
37. The Board directs EAL to establish a process to record the cost of the transmission facilities broken down by the categories listed below, together with reasons why the facilities should be so classified as follows:
  - local identifiable generation connection facilities
  - local identifiable load connection facilities
  - reliability transmission upgrade facilities
  - commercial transmission upgrade facilities (Section 13)

### 2001-32 Directives

20. Accordingly the Board directs EAL, in future cost of service studies, to include the cost of facilities that are classified to system as “reliability transmission upgrade facilities” and the cost of facilities classified to customer as “local identifiable load connection facilities”. (Page 123)
  
21. However, the Board considers that this study does not have a high priority. The Board considers that the process of categorizing new transmission additions will appropriately capture the growth component and provide insights towards the appropriate classification of the historical existing system.

Accordingly, the Board directs EAL, in its 2003 GTA, to carry out a cost of service study of the Alberta transmission system to determine the appropriate classification of supply and load customer transmission costs to demand and energy and submit the results of the study and EAL’s recommendations when filing its 2003 GTA. Further, the Board directs EAL to study the use of CP to recover all or a portion of energy costs and directs EAL, in its 2003 GTA, to recommend appropriate changes to the TA’s tariff structure when filing its 2003 tariff. (Page 124)

## 8. Appendix A – Electric Utilities Act – Section 30

- (1) The Independent System Operator must submit to the Board, for approval under Part 9, a single tariff setting out
  - (a) the rates to be charged by the Independent System Operator for each class of system access service, and
  - (b) the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.
- (2) The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, and the rates must
  - (a) be sufficient to recover
    - (i) the amounts to be paid under the approved tariff of the owner of each transmission facility,
    - (ii) the amounts to be paid to the owner of a generating unit in circumstances in which the Independent System Operator directs that a generating unit must continue to operate, and the costs to make prudent arrangements to manage the financial risk associated with those amounts,
    - (iii) farm transmission costs, and
    - (iv) any other prudent costs and expenses the Board considers appropriate,
  - (b) either be sufficient to recover the annualized amount paid to the Balancing Pool under section 82(7), or if the Independent System Operator receives an annualized amount under section 82(7), reflect that amount, and
  - (c) include any other costs, expenses and revenue determined in accordance with the regulations made by the Minister under section 99.
- (3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

(4) The Independent System Operator may recover the costs of transmission line losses and the costs of arranging provision of ancillary services acquired from market participants by

(a) including either or both of those costs in the tariff, in addition to the amounts and costs described in subsection

(2), in which case the Board must include in the tariff the additional costs it considers to be prudent, or

(b) establishing and charging ISO fees for either or both of those costs.

The determination of rate classes that will be subject to transmission costs is an issue being dealt with in the proposed transmission regulation. Since this regulation is not yet finalized, this cost of service study will work with the existing assignment of costs to generation and load. This report will investigate costs irrespective of rate classes, and therefore the rate design can use the recommendations of this report, regardless of whether costs are recovered from generation or load.

## 9. Appendix B – Excerpt from Transmission Policy

The following is an extract from the Alberta Transmission Development Policy, issued by Alberta Energy on December 22, 2003

**3. Transmission embedded costs will be collected from consumers based on their use of the transmission system. Generators will be required to pay for local interconnection costs and to make a financial commitment and payment for transmission system upgrades based on their size and location on the system. Economic signals and prices from the wholesale electricity market should not be adjusted or unduly distorted with transmission costs.**

### **Embedded Costs**

The 50/50 pricing regime currently used for embedded costs will be discontinued effective January 1, 2006. Three important objectives are met by removing this pricing regime; (a) price distortions are not introduced into the wholesale market from the regulated transmission business, (b) consumers receive transparent pricing for transmission service, and (c) the market and pricing rules of Alberta are further aligned with those of neighboring jurisdictions.