Alberta Transmission Tariff Studies

November 30, 2018

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Agenda

- 2006 Wires Cost Study
- 2006 Ancillary Services Cost Study
- 2010 Operating and Maintenance Cost Study
- 2014 Cost Causation Study

2006 Wires Cost Study

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2006 Wires Cost Study - EEMA

- Prior to the industry restructure, transmission costs in Alberta were pooled within the Electric Energy Marketing Act (EEMA).
- The pooled costs were used by the vertically integrated utilities in their Cost of Service Studies to allocate to the various rate classes for end use customers.
- Transmission rates were based on the coincident peak load in each month, with a 75% weighting on the three winter months, and a 25% weighting on the nine non-winter months.

2006 Wires Cost Study - EUA

- Transmission tariff that recovers the cost of transmission from load
- Rate for transmission system access service must be the same for all distributors and transmission connected load, regardless of location on the transmission system

2006 Wires Cost Study - Method

- Reviewed the embedded cost of transmission, and was not a marginal cost study
- Functionalized transmission system
- Costs of each function were reviewed to see how the costs were incurred
- Costs of each function were classified as customer, demand or energy related

2006 Wires Cost Study - Data

- 2003 wires costs were $383 million (total $734 million)
- Sum of net book value of transmission property from the four largest TFO’s was $1.5 billion (at end of 2002)

2006 Wires Cost Study – Planning Criteria

- Decisions made at the planning stage drive costs
- Transmission planning criteria are sometimes referred to as reliability criteria, but planning criteria are more than reliability criteria
- 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 facilities may also be justified on the basis of the economics in the reduction of line losses and ancillary services

2006 Wires Cost Study – Planning Criteria(2)

- 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

2006 Wires Cost Study – Review

- Transmission rates varied widely across Europe where some countries imposed a small fixed charge on consumers, to countries where demand charges consisted of more than 80% of the total rate (Germany), to countries where the entire transmission rate consisted of a variable charge (energy based
- Ontario used “assessment of the options”
  - Network (58%, looped lines and high voltage substations) billed on higher of coincident peak demand and 85% of peak demand
  - Transformation (26%, over 50kV to below) billed on peak demand
  - Connection (16%, radial) billed on peak demand
- PJM used one co-incident peak

2006 Wires Cost Study – Functionalization

- Overlying, underlying and delivery
- Differentiated by:
  - Complexity in planning
  - Impact of failure
  - Diversity of load

2006 Wires Cost Study – Functionalization(2)

- Hard rules without judgement or soft rules with judgement
- By voltage level
  - does not capture change over time, difference between remote/rural versus urban areas
- By economics
  - academic, does not reflect evolution over time, biased to functionalizing as overlying
- By winter peak usage
  - based on forecast flow, subjective cut point, possibly volatile

2006 Wires Cost Study – Classification

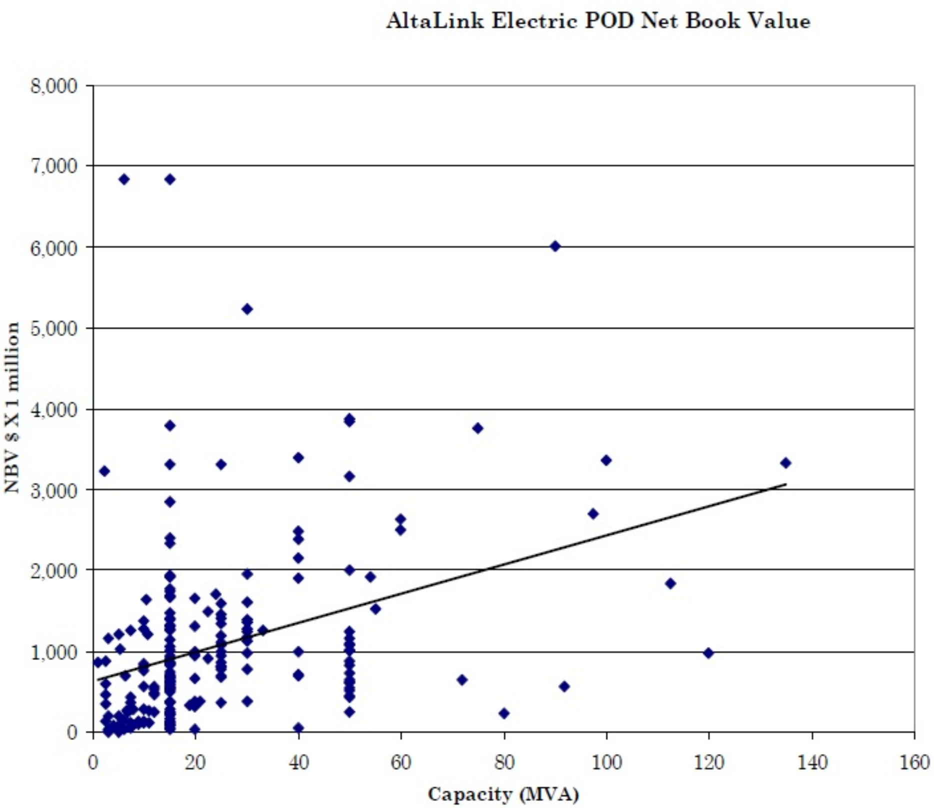
- While transmission planning models consider one point in time (i.e. forecast demand), transmission planning criteria are based on experience and judgment
- A portion of cost can be considered caused by factors other than demand, such as:
  - Location of generation
  - Dispatch of generation
  - Imports and exports
- Minimum system approach assigns additional cost (of optimizing the system) as energy related

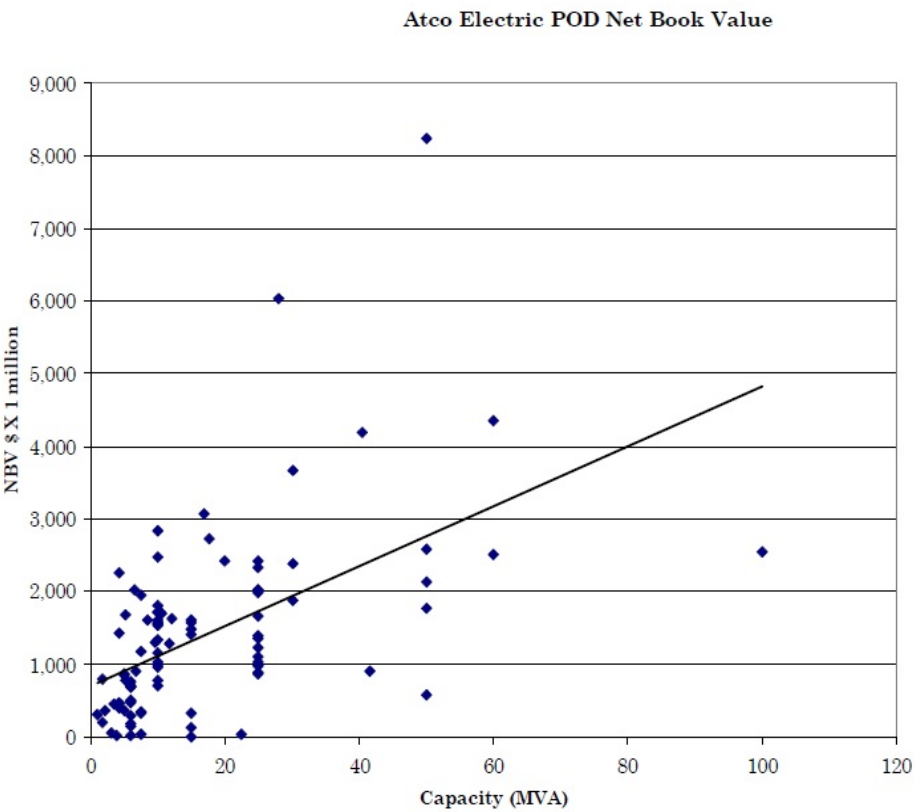
2006 Wires Cost Study – Classification(2)

- transmission facilities at point of delivery are sized to meet customer peak, and the further you go back into the system, the system is designed to meet the load coincident to the system load at the time of maximum stress on the system
- demand at the time of peak bulk system stress is not a practical demand related billing parameter because customers do not generally have visibility as to the time of maximum bulk system stress (and further, the time of peak stress will vary at different points in the system)
- recovery of bulk 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 maximums bulk system stress

2006 Wires Cost Study – Classification(3)

- POD cost function was a single straight line with a non-zero intercept





2006 Wires Cost Study – Results

	Bulk System	Local System	POD
• Demand	81.5%	82.5%	43.1%
• Energy	18.5%	17.5%	0.7%
• Customer			56.2%

2006 Ancillary Services Cost Study

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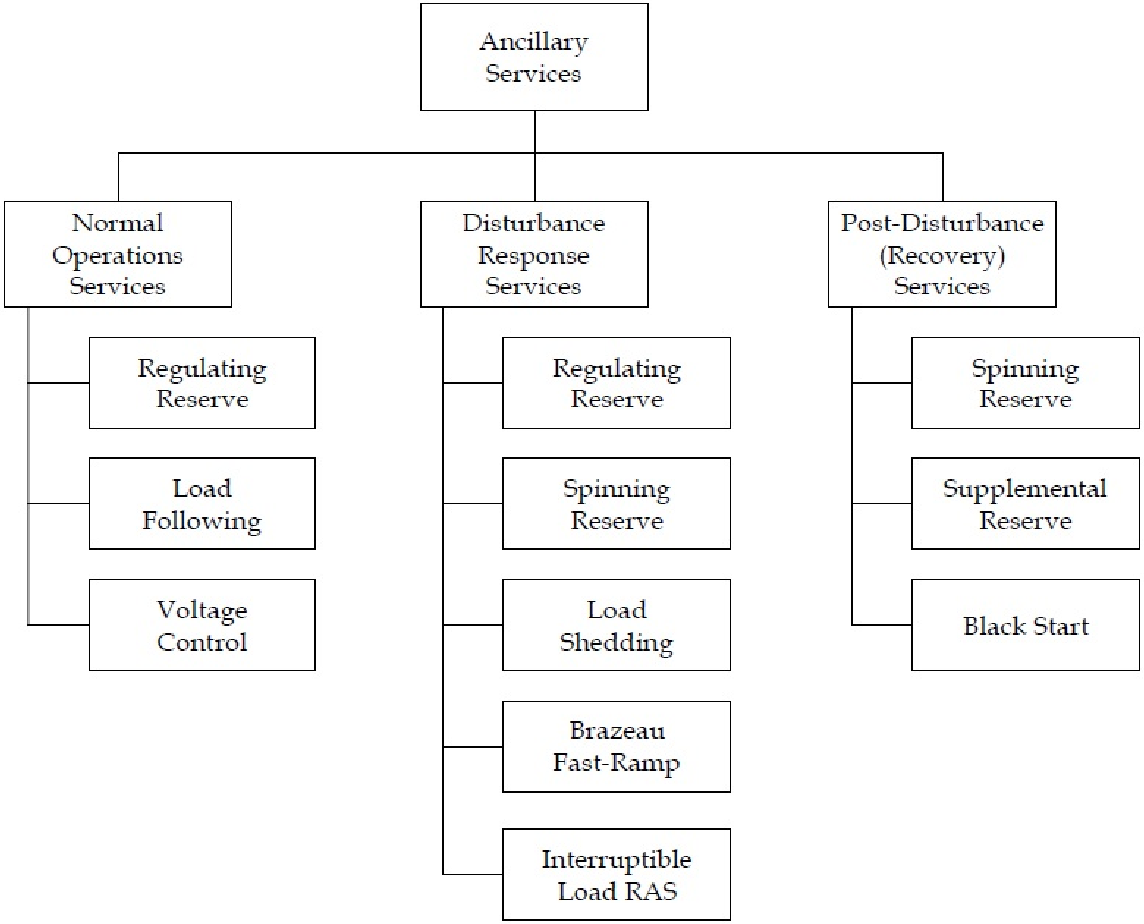
2006 AS Cost Study - Overview

Figure 2.1: The ancillary services used in Alberta.



RAS = "Remedial Action Scheme"

2006 AS Cost Study – History

- Board allocated the cost of all ancillary services to Rate GIS (Grid Interconnection Service), which applied to distribution utilities on the basis of their non-coincident peak demands in Decision U97065 (Oct 1997).
- Decision 2000-1 (Feb 2000)
  - that payments to providers would reflect energy-market opportunity costs, the Board ruled that the operating reserve charges should be energy-based
  - TMR costs were incurred on an energy basis, they should be recovered that way
  - voltage control is crucial to load, and because the associated costs are fixed and do not vary with pool price, voltage control costs should be charged to load on a 100% demand basis
  - with respect to dual-use customers, the Board ruled that they should be gross billed

2006 AS Cost Study – History(2)

- Decision 2001-32 (May 2001)
  - Board ruled that the TA could use 1-minute metering for demand charges associated with the Poplar Hill plant and ILRAS (60% demand like wires),
  - and for energy charges associated with operating reserves, generator RAS and black start, load following, and voltage control (including TMR and hydro motoring)
  - there should be no demand ratchets applied to demand related ancillary service charges
  - The Board also directed EAL, in the 2003 GTA, to include rate proposals for unbundling ancillary services and proposals for customer self-supply of ancillary services

2006 AS Cost Study – Operating Reserve

- OR costs are volatile and their distribution changes significantly over time as market conditions change
- Neither the current rate design (% of pool price), nor a rate design having a fixed cost per DTS MWh, provide a good match between costs and revenues on an hour-to-hour basis
- Forecasting under such conditions is extremely difficult for both the AESO and for customers, who may face deferral account reconciliations and/or rate riders

2006 AS Cost Study – Regulating Reserve

- use of energy as the basis for regulation charges results in customers with large, stable loads paying more for regulation than customers with smaller but highly variable loads
- regulation costs depend on factors other than energy consumption, there is an unavoidable mismatch between costs and revenues on an hourly basis
- method for calculating each customer’s contribution to the requirement for regulating reserve (including the load following component) is available and should be considered for implementation

2006 AS Cost Study – Spinning and Supplemental Reserve

- hourly energy consumption is the appropriate billing determinant for spinning and supplemental reserves
- setting the price of spinning and supplemental reserves equal to a fixed percentage of pool price leads to large discrepancies between costs and revenues
- change in the spinning and supplemental reserve rate structures may be warranted

2006 AS Cost Study – Voltage Control

- TMR costs represent a large fraction of the AESO’s total voltage control cost
- TMR charges are proportional to pool prices, while the AESO’s TMR payments are roughly *inversely* proportional to pool prices
- Consideration should be given to developing an alternative rate design that can track costs more closely
- There are several factors that determine the requirement for TMR and other voltage control services, there is no “obvious” billing determinant for those services
- A reasonable alternative would be to allocate costs based solely on energy consumption

2006 AS Cost Study – Others

- Amount of load protected by UFLS is more strongly related to the load on the system at the time than to the loads' peak demands. Thus, an energy based cost allocation is fair and reasonable
- ILRAS costs are treated as a substitute for contingency reserves, then it makes sense to allocate the costs in the same way contingency reserves costs are allocated (i.e., on an energy-only basis)
- Black start service restores the loads that were on the system immediately prior to the outage. Consequently, hourly energy rather than monthly or annual peak demand is the appropriate billing determinant

2006 AS Cost Study – Conclusions

- Recommended that alternative rate designs, which may provide a better match between costs and revenues while maintaining other import attributes of a sound rate design
- Billing determinant currently used for regulating reserve (i.e., energy consumption) is not necessarily the best one, and that the variability—or range of up-and-down movement—of a load’s energy consumption may be a better choice
- For the other ancillary services the traditional billing determinants of peak demand and energy are appropriate, though in certain cases a switch from one to the other may be considered

2010 Operating and Maintenance Cost Study

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2010 O&M Cost Study – Background

- Study filed with 2007 tariff application was based on capital costs alone
- Operating and Maintenance costs were assumed to track capital costs
- Decision 2007-106: The Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs

2010 O&M Cost Study – Costs

- Costs sorted as Capital or Non Capital Costs
  - Capital costs include depreciation, debt servicing, return, and income taxes
  - Non capital costs defined as those costs not closely tied to capital investment and those where management has some discretion
- Some costs considered non capital exhibit the characteristics of capital related costs
  - Linear taxes (taxes other than Income)
  - Structure payments
  - Capital related revenue offsets

2010 O&M Cost Study – Non-capital Costs

- Non Capital Costs sorted as:
  - Operating and Maintenance (O&M)
    - O&M costs linked to operation and maintenance of the electric transmission system
  - General and Administration (G&A)
    - G&A costs linked to running the business such as cost of hearings, self insurance and business tax

2010 O&M Cost Study – Method

- Voltage level method is easy to understand and correlates to electric transmission facilities, voltage levels were used to functionalize O&M costs
- Considered the incurrence of various O&M costs in order to functionalize the costs
  - For system control center, the number of elements (lines and transformers) in service is used to functionalize costs
  - Brushing costs are a function of the area cleared. Therefore, the line length (by voltage) is multiplied by the width of the right of way for brushing to determine the total amount of area

2010 O&M Cost Study – Classification

- Operations and Maintenance can not be reliably classified
  - Operations and Maintenance work is completed on facilities to ensure that they operate reliably and efficiently to meet their original design specifications
- Operations and Maintenance is classified on the same basis as capital

2010 O&M Cost Study – Summary

- Non Capital Costs account for 30% of the Revenue Requirement
- O&M costs account for 2/3 of the Non Capital Costs
- Functionalized Non Capital Costs have increased weight on POD and Local functions with reduced weight on Bulk

2010 O&M Cost Study – Results

Table 1 Summary Results

Breakdown of Capital Costs (2007 GTA)	Bulk System	Local System	POD	Totals
Demand Related	34.0%	14.3%	17.6%	66.0%
Energy Related	7.7%	3.0%	0.3%	11.0%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	41.7%	17.4%	40.9%	100.0%
Breakdown of Non Capital Costs	**Bulk System**	**Local System**	**POD**	**Totals**
Demand Related	13.5%	25.2%	17.6%	56.2%
Energy Related	3.1%	9.0%	8.8%	20.9%
Customer (POD)	0.0%	0.0%	22.9%	22.9%
Totals	16.5%	34.2%	49.3%	100.0%
Weighting for Capital and Non Capital Costs				
Capital Costs Portion	71.4%			
Non Capital Costs Portion	28.6%			
Weighted Capital and Non Capital	**Bulk System**	**Local System**	**POD**	**Totals**
Demand Related	28.1%	17.4%	17.6%	63.2%
Energy Related	6.4%	4.7%	2.7%	13.9%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
Totals	34.5%	22.2%	43.3%	100.0%

2010 O&M Cost Study – Pre-paid

- To minimize any subsidies between new customers and existing customers
- New customers that interconnect must pay for Optional Facilities in the form of contribution
- New customers must also pay for the incremental O&M associated with Optional Facilities on a prepaid basis
- Existing rate is 12% of Replacement Cost New
- Alternative rates are:
  - Based on Non Capital Costs/RCN: about 20%
  - Based on O&M Costs/RCN: about 14.5%
  - Based on Incremental Maintenance/RCN: about 2.5%

2014 Transmission Cost Study

Public

2014 Transmission Cost Study – Review

- Ontario (2013 values $/kW)
  - Network Service Rate: $3.63 (at higher of coincident peak, or 85% of peak demand on weekdays between 7AM and 7PM)
  - Line Connection Service Rate: $0.75 (at Non-Coincident Peak demand (MW) in any hour of the month)
  - Transformation Connection Service Rate: $1.85 (at Non-Coincident Peak demand (MW) in any hour of the month)

2014 Transmission Cost Study – Review(2)

- California
  - High Voltage (200 kV and over) Access Charge is a uniform $/MWh rate for all Participating Transmission Owners (PTO) loads
  - Low Voltage (below 200 kV) Access Charge is a unique $/MWh rate for each PTO’s area load

2014 Transmission Cost Study – Review(3)

- Australia - contract agreed maximum demand

Customer Group of Connection Points	Voltage (kV)	Exit Price ($/day)	TUOS Locational	TUOS Non-Locational		Common Service	
			Capacity Price ($/MW/day)	Capacity Price ($/MW/day)	Energy Price ($/MWh)	Capacity Price ($/MW/day)	Energy Price ($/MWh)
Adelaide Eastern suburbs	66	10,800	67.405	108.307	11.697	33 207	3.586
Adelaide Southern suburbs	66	11,757	53 680	108.307	11.697	33 207	3.586
Adelaide Western suburbs	66	3,944	44 624	108.307	11.697	33 207	3.586
Para subsystem	66	6,101	43 367	108.307	11.697	33 207	3.586
Port Pirie subsystem	33	2,478	128 047	108.307	11.697	33 207	3.586
SA Water sites	33/11/3 3	-	151.122	108.307	11.697	33 207	3.586

2014 Transmission Cost Study – Review(4)

- Great Britain - Transmission Network Use of System ("TNUoS") tariff is composed of two components:
  - locational component is classified using a marginal cost methodology known as the Investment Cost Related Pricing ("ICRP")
    - increases or decreases in units of kilometers of the transmission system, for a 1 MW injection to the system
  - residual, non-locational component of the TNUoS tariff is meant to recover the remaining amount of the revenue requirement
    - marginal cost model assumes smooth, incremental investment. The difference between actual lumpy system and theoretical incremental system is accounted for by the residual component

2014 Transmission Cost Study – Review(5)

Figure 23. Schedule of Transmission Network Use of System Demand Charges (£/kW) and Energy Consumption Charges (p/kWh) for 2013/14*

Demand Zone	Zone Area	Demand Tariff (£/kW)	Energy Consumption Tariff (p/kWh)
1	Northern Scotland	11.049	1.515
2	Southern Scotland	16.790	2.363
3	Northern	22.347	3.080
4	North West	25.184	3.651
5	Yorkshire	25.485	3.509
6	N Wales & Mersey	25.631	3.665
7	East Midlands	28.213	3.957
8	Midlands	29.201	4.149
9	Eastern	29.892	4.153
10	South Wales	27.542	3.685
11	South East	32.827	4.564
12	London	34.083	4.601
13	Southern	33.752	4.741
14	South Western	33.552	4.598

*Source: National Grid. The Statement of Use of System Charges. Effective from April 1, 2013. * Rounded to 3 decimal places*

- Generation charges based on maximum installed capacity (kW)
- 30-minute metered loads are charged the average “triad” demand multiplied by the zonal demand tariff (£/kW), where triad means the three half-hours between November and February (inclusive) with the highest peak system demand. The triad half-hours must be separated from system demand peak and each other by at least ten days. Other metered loads are charged actual energy consumption (kWh) for the hours of 16:00 to 19:00 inclusive, multiplied by the energy zonal energy consumption tariff (p/kWh).

2014 Transmission Cost Study – Method

- Generally can be considered an update of prior studies

2014 Transmission Cost Study – Results

Capital cost functionalization	2014	2015	2016
Bulk	61.0%	66.7%	66.9%
Regional	20.6%	18.5%	18.1%
POD	18.4%	14.8%	15.0%

O&M cost functionalization	2014	2015	2016
Bulk	20.8%	20.8%	20.8%
Regional	39.2%	39.2%	39.2%
POD	40.0%	40.0%	40.0%

Combined cost functionalization	2014	2015	2016
Bulk	52.8%	58.2%	59.2%
Regional	24.4%	22.3%	21.6%
POD	22.8%	19.5%	19.2%

Classification results	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

Thank you

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