The Role of Interties in the Alberta Market

A Report Prepared for the Independent Power Producers Society of Alberta

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This report is being prepared at the request of the Independent Power Producers Society of Alberta (IPPSA). IPPSA has asked for an independent evaluation of the impact of expansion of intertie capacity between Alberta and other jurisdictions in the future, and for an opinion regarding the competitive conditions that underpin current trading relationships between neighboring provinces. Several very rigorous and focused reports have been completed recently that bear on these issues, and we draw upon them in order to establish the base of data and analysis that frames the issue. These are referenced in the report and in the attached bibliography.

We have been asked to comment on four areas that may affect future Alberta electricity generation capacity and investment as a function of intertie operation and potential expansion. These areas are:

- The efficacy of current trading relationships across the BC/Alberta intertie (level playing field issue)
- Whether expansion of the intertie capacity in the future may adversely affect future investment in Alberta generation capacity
- The operational fairness of rules governing participation and charges for generators seeking to use the intertie
- The impact of intertie capacity and utilization on intra-Provincial generator investment and cost recovery

We have undertaken this report utilizing only publicly available data from various power organizations in Alberta, as well as reports specifically commissioned by IPPSA in order to address these questions. No additional original research was undertaken in this process.

The issue of intertie capacity is important to Alberta generally, and to Alberta independent power producers specifically, due to the impact of import/export flows on the Alberta electricity market and the bidding activities associated with its operations. The ability to import and export power affects prices, which consequently affects incentives to build or refurbish existing capacity within the province, as well as long-term system dispatch characteristics including renewable energy[1] or thermal energy generation. As well, underlying all the issues regarding market performance is the concept of a healthy and responsive marketplace, which we define as a market where adequate supplies are efficiently provided to match consumer demand and long term capacity needs are driven by clear price signals.

There are four important areas in which intertie capacity can influence operations and pricing within the Alberta electric system. They include:

1. Engineering Efficiency of System Operations (not addressed in this report)
2. Economics and Consumer Pricing
3. Energy Policy and Market Power
4. Investment Incentives short and long term

[1] Renewable energy resources are price-takers that are difficult to dispatch.

I. Alberta and Energy Only Markets

The principal reason for considering an energy-only market approach to achieving resource adequacy is the expectation that it will allow market incentives, rather than centralized administrative direction, to drive investment decisions. The rationale is consistent with the principal reasons for departing from the historical regulatory structure. A key objective of energy-only markets is that prices can be determined without either administrative price caps or other interventions that might depress prices below high opportunity costs and leave money missing from market participants.

The real-time prices of electric energy, and participant actions, including contracting and other hedging strategies in anticipation of these prices, are assumed to be the primary drivers of decisions in the market. The principal investment decisions are still made by market participants; the result is that this decentralized process should improve innovation and efficiency.

A key objective of planners and regulators is to avoid the problem of leaving customers with stranded costs arising from decisions not driven by competitive choice. From this perspective, the rewards of an energy-only market are improved innovation and efficiency, fewer stranded costs, and shifts of the risks and (some) rewards of appropriate investment from consumers to investors.

Alberta's market does not pay for installed capacity (ICAP) and there is no need to pre-acquire or contract for capacity with attendant markets. Generators can recover these costs through the enhanced profit margins (scarcity rents) they earn from selling energy and ancillary services, rather than through direct payments earmarked to recover those costs[2]. Scarcity rents work to promote resource adequacy to respond to growth in demand, where as the generation reserve margin shrinks, price-responsive demand curtails consumption with increasing frequency in order to compensate for any shortfalls in generating capacity.

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[2] As pointed out by Stoft, the term, energy-only market, is something of a misnomer that actually refers to a series of closely linked sub-markets for spot energy, operating reserve, other related ancillary services and bilateral contracts. **The common bond is that all depend on cost-reflective, transparent spot energy prices in order to function efficiently and effectively.**

At the core of all these issues, however, must be consideration of reliability and security. NERC defines two components of reliability:

Security: "ability to withstand sudden disturbances"

– Short-term or delivery reliability

– Common-language meaning of "reliability"

Adequacy: "ability to supply demand and energy"

– Long-term or planning reliability or a concern with resource adequacy, especially in a competitive environment, is a concern that price will not call forth supply. If supply is available but expensive, resources are adequate – adequacy is an engineering rather than economic concept

The more often price-responsive (elastic) demand sets the energy price[3] the greater the scarcity rent and the higher potential profits generators can earn in the future effectively the Value of Lost Load (VOLL) which is assumed to be higher than individual generator's marginal cost. This should continue until investors' expectations regarding future scarcity rent reaches a level sufficient to justify new peaking capacity investment (or conversely it shows a point where new peaking capacity can be avoided). As the new plants enter service they will slow down further declines in the generation reserve margin and maintain equilibrium.

Electric generation is extremely capital intensive, with very long-lived assets, ranging from 50 years for thermal generation capacity to potentially more than 100 years for hydroelectric facilities. Investors have been attracted to this industry because of the stability and predictability of the system. This relationship can be detrimentally altered when confidence is eroded by policy interventions as opposed to consistent regulatory oversight. The clearest example of this reflects rule sets that create unfair or uneven cost advantages between or within generation categories.

[3] A key problem in this area is the reliance on price responsive demand to allocate resources efficiently during periods of scarcity, which is difficult in a Province like Alberta with little price responsive load.

II. Background Conditions

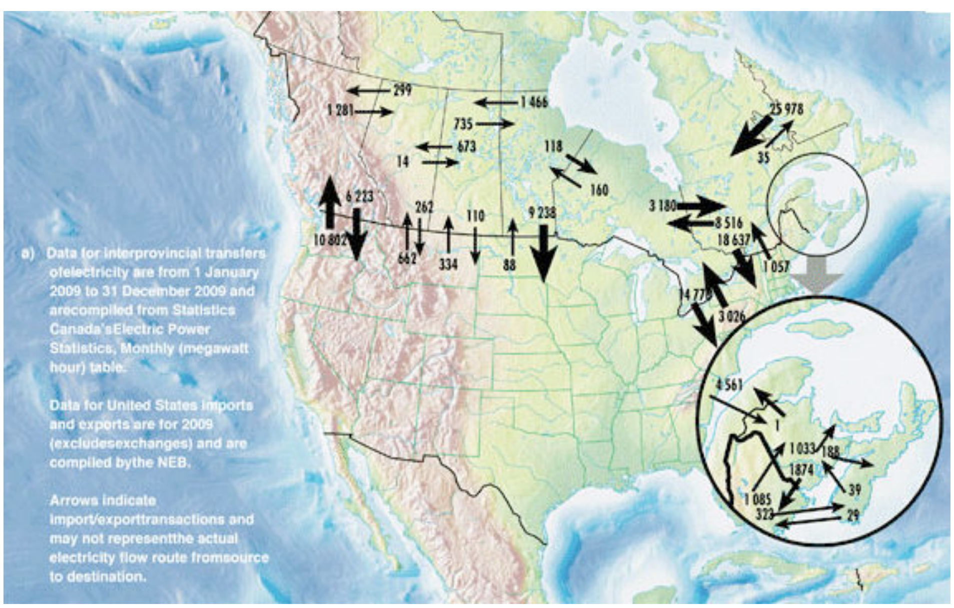
a. General

Canadian provinces typically operate electricity systems independently, focused generally on their own resources, with major export activity directed predominantly to the south over time. Interprovincial balancing and load management with import/export capacity is a relatively recent phenomenon. The direction and volume is shown in Figure 1, below. The figure illustrates the preponderance of high volume transfers are in and out of provinces where the primary source of power generation is associated with hydroelectric facilities.

This is commented on in the Brattle[4] report, to wit:

> "Alberta currently is only weakly interconnected with neighboring systems, but the Alberta government, in its Provincial Energy Strategy, has set out a policy objective of expanding interties with neighboring markets. By expanding these interconnections, the government aims to increase reliability, supply adequacy, market competitiveness, and access to wind generation. However, expanding interconnections to neighboring markets, all of which have resource adequacy requirements, also introduces risks that must be monitored carefully. This includes the possibility that the interaction with external markets could depress Alberta market prices and deter needed investment in new resources, thereby decreasing long-term supply adequacy and reliability".

Figure 1: Transmission Connections and Transfer



Source: National Energy Board, 2009

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[4] Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market, Brattle Group, J.P. Pfeifenberger & K. Spees, April 2011, pg. 32

b. Alberta Electricity Market

The Province of Alberta is served by a partially deregulated[5] electric market dominated by thermal electricity generation, interconnected with limited capacity to British Columbia and Saskatchewan and with a limited balancing tie to Montana. Market operation, including dispatch, settlement and planning, is operated by the Alberta Electric System Operator (AESO), a non-profit and independent entity. AESO directs the real-time operation of the Alberta Interconnected Electricity System, and manages the transmission system in Alberta. The System Coordination Centre monitors demand and dispatches electricity to meet system demand.

c. BC Electricity Market

The BC electricity market is operated by BC Hydro, a Crown corporation. As of July 5, 2010, BC Hydro and BC Transmission Corporation were consolidated. BC Hydro has two wholly owned subsidiaries, Powerex Corp and Powertech Labs Inc.

Powerex buys and sells wholesale electricity. Powertech Labs provides testing, consulting, and research services to the electric and natural gas industries, their customers and suppliers. BC Hydro's primary business functions are the generation and distribution of electricity. The BC Hydro Public Power Legacy and Heritage Contract Act ensures British Columbia's electricity assets, including transmission and distribution lines, must remain publicly owned.

[5] In 2001, the deregulated market opened. It allowed full wholesale competition, and competition in the retail electricity market, in tandem with a regulated rate option default product. Transmission remained regulated.

Table 1

Comparison of Alberta and British Columbia Market Structures

	Alberta	British Columbia
Market Organization	Partially deregulated. Market operation, including dispatch, settlement and planning, is operated by the Alberta Electric System Operator (AESO), a non-profit and independent entity. Distribution is partially deregulated. Transmission is regulated.	The BC electricity market is operated by BC Hydro, a Crown corporation. BC Hydro's primary business functions are the generation and distribution of electricity. The BC Hydro Public Power Legacy and Heritage Contract Act ensures British Columbia's electricity assets must remain publicly owned.
Prices	Electricity prices are competitive and are set by daily and hourly market bids from participants. There are 164 participants in the generation market.	The BC Utilities Commission determines "just and reasonable" rates to be charged by BC Hydro.
Transmission	The tariff for transmission access is set by the Alberta Utilities Commission	Tariff set by BC Utilities Commission.
Distribution	Consumers have the choice between a regulated rate (set by the Alberta Utilities Commission) or a market rate for electricity provided by an unregulated "energy marketer."	Operated by BC Hydro.
Generation capacity	13,535 MW	Between 43,000 and 54,000 GWh of electricity annually
Installed capacity	coal 44% natural gas 41% hydro 7% wind 6% alternative 2%	30 hydroelectric facilities 3 natural gas-fuelled thermal power plants

d. Management of the BC/Alberta Intertie

The Alberta-BC intertie consists of one 500 kV circuit and two 138 kV circuits. BC also has two 500 kV lines and two 230 kV lines connecting BC to the United States. Powerex "trades electricity with other jurisdictions to ensure B.C. ratepayers are able to get the best value from BC Hydro's generation infrastructure. Powerex purchases electricity from neighbouring jurisdictions when prices are low and then sells electricity when the market price is higher. Any net income from trading, up to $200 million, is returned to BC Hydro ratepayers through lower electricity rates."

According to the Brattle Group,

> "The BC Hydro intertie is currently operating with available transfer capability (ATC) less than its design capacity due to Alberta internal transmission constraints and other operational restrictions. The BC Hydro intertie has a design rating of 1,200 MW for imports and 1,000 MW for exports, but currently has a maximum ATC value of only 650 MW for imports and 735 MW for exports. The Saskatchewan intertie design rating is 150 MW for imports and exports and its ATC has recently been restored to its design rating. The ATC on the BC Hydro intertie is also anticipated to be restored to its original design ratings after the creation of intertie restoration products including load shed service and other system enhancements. In addition to restoring intertie ATC to design rating, there is one intertie project that will further expand Alberta's interconnections with neighboring markets, although it will not necessarily increase ATC. This new intertie is the 300 MW Montana-Alberta Tie Limited (MATL) line that is currently under construction with an estimated online date in late 2011. In addition, the AESO has begun considering several other potential interconnection options, although specific projects have not yet been determined".[6]

According to the MSA[7], market power concerns are minimized in the current arrangement by requiring all importers to price at zero, removing the chance they will be the marginal producer. In a similar role, the AESO can reduce the ATC of the intertie so that supply from BC is no bigger than the other single largest provider of generation in Alberta. The AESO informal policy is to mitigate the tendency for in-province market power by having the intertie supply capped at approximately 20% of peak. They restrict this capacity in part to ensure that the grid is not overly dependent on any one producer.

Similar to most thermal generation facilities, the intertie is taken offline one week each year for maintenance. During that period, prices are predictably higher, approximating the prices as if all generation were required to produce from within the province.

The MSA believes the addition of the Montana intertie won't add significant new capacity because it will cross the border close to the BC intertie, effectively adding capacity at the same point where the BC intertie does. This means the additional

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[6] Brattle Group,

[7] Personal Communication, M. Ayers, Alberta MSA, July 31, 2011

generation capacity from Montana effectively "competes" with BC for "space" on the Alberta grid. At this point, there is nothing formal in the adopted AESO long term plan discussing adding intertie capacity.[8]

Fundamental Characteristics of the Alberta Market

In the recent report by the Brattle Group, the authors draw important conclusions regarding the success, stability and forecast capacity of the Alberta "energy only" market, which are worth summarizing.

Their analysis shows that the Alberta market design is generally well-functioning, with energy and ancillary service prices that have been relatively *low* when reserve margins were high, but that have increased enough to attract new plant additions when system-wide reserve margins declined.

Their projections of future energy and ancillary service prices were based on recent market conditions and showed that only modest increases in market prices, consistent with projected increases in natural gas and carbon emission costs, should be sufficient to avoid premature retirement of existing resources and, importantly, support investments in new generation. They do not identify or call out a compelling need for major changes in Alberta's electricity market design as a result of design or operational flaws and believe the market conditions are rewarding the choice of this type of market design.

In a cautionary note, however, the authors go on to point out a potential future shortcoming in the Alberta market, namely that "It also needs to be recognized that an energy-only market design will not be able to "guarantee" that a certain reserve margin will be maintained".

They conclude with a recommendation that "The AESO should carefully consider the long-term resource adequacy implications of its efforts to refine the Alberta market design, which include: (1) the integration of additional wind generation; (2) refining ancillary service markets and market designs for demand response; and (3) the expansion of interconnections with neighboring systems".

This implies a fragility or vulnerability of system design, in the sense that when external conditions change or supersede existing practices, the investment signals for new capacity in Alberta may become compromised. Just as compelling, however, is the notion that *increased* reliance on another system, such as British Columbia's, is not inherently desirable, nor supportive of the long term Alberta market design. The long-term priority of the British Columbia system is always based on their own constituency, and the intertie, while convenient, can be substituted in other ways. Maintenance of the Alberta energy-only market implies a resilience that must be based on adequate physical as well as virtual surplus.

[8] Recent consultations have included the issue of expanding the intertie(s).

The Role of the Interties

From the Alberta perspective, and as the AESO has discussed in a recent publication, "Transmission interconnections, or interties, with neighbouring jurisdictions are essential to a well functioning Alberta electricity market as they support reliability, market diversification, generation development and continued economic growth in Alberta."[9] Alberta's energy-only market, with no transmission rights and only opportunity service on the interties, connects to neighbouring jurisdictions and markets where "firm" transmission rights are sold to the border.

The AESO currently manages congestion on the interties and ATC allocation via the scheduling process and approves all schedule submissions (known as "e-tags"). If the submitted volume is greater than the available transfer capability of the intertie, the neighbouring transmission provider, currently BC Hydro or SaskPower, will curtail according to their priority given they sell transmission products which act as priorities or "rights". If BC Hydro or SaskPower do not curtail enough volume by 15 minutes before the scheduled hour, the AESO, as the transfer path operator, has a policy to curtail transmission import schedules on a last-in-first-out basis according to the timing of e-tag approval.

Interties provide a different reserve product than an intra-Alberta generator. Intertie energy can be viewed as an opportunistic supply. It flows to the Province when there is sufficient excess transmission capacity between the exporting region and load and no higher value destination for that energy (domestic emergency or higher priced export market) exists at that time. Currently intra-Alberta generation dedicated to reserve capacity must response not only to rules but also to a price signal; as well, it can also be conscripted by the System Operator in the event of a system emergency. Imported energy cannot be ordered or "conscripted" by the Alberta System Operator.

In 2008, Alberta's Provincial Energy Strategy stated the province's intention to adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta. As new interties were being contemplated from adjacent balancing authorities, a review of the intertie framework was required to ensure it supported fair, efficient, and openly competitive intertie transactions while advancing government policy.[10]

The Influence on Operations/Reserve Margins

The Alberta market depends on competitive signals to incent new capacity additions. Included in this type of market signal are reserve margins, where predictable and consistent reserve requirements can help to maintain system stability, but must be viewed in terms of consistent and equitable cost recovery for generators. Meeting these requirements without growth in generation within the service area (as opposed to

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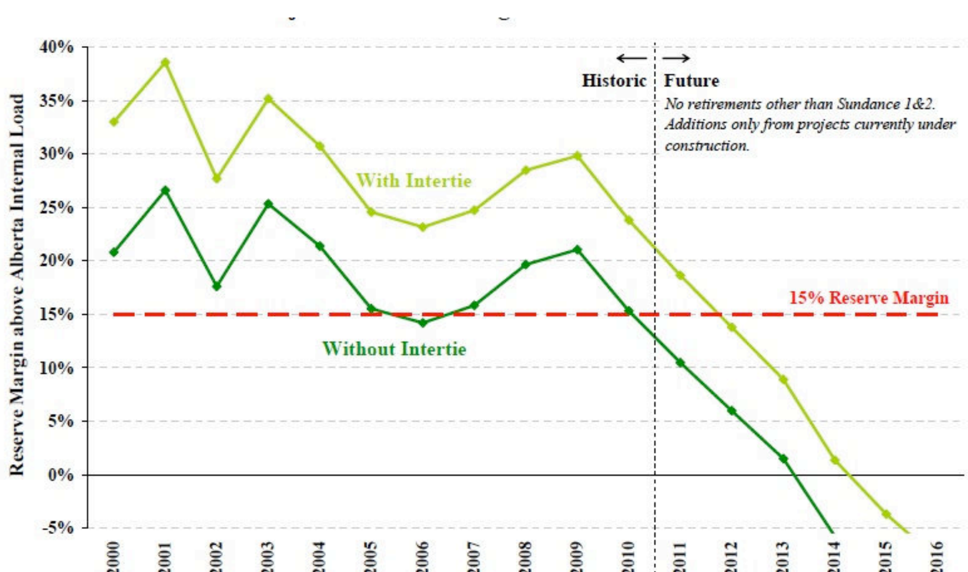
[9] AESO Intertie Framework, October 7, 2010
[10] Letter of Notice – Consultation on Proposed New ISO Rules and Proposed Removal of ISO Rules, March 17, 2011

expanded capacity via the intertie) can potentially negatively affect reserve capacity and system stability. The inference is that a "level playing field" between independent and cost of service-based generation in meeting needs should include import capacity for the market to behave efficiently. This is suggested by the Brattle Group:

> "Since 2000, reserve margins in Alberta have ranged from 14% to 27% over Alberta Internal Load without the interties, and from 23% to 39% with the interties. This reserve margin range has been generally above or close to the 15% reserve margin benchmark as an approximate indicator of resource adequacy, although the 15% is not an official target and may exceed the economically efficient reserve margin. Reserve margins have been lower during the past several years than they were at the beginning of the decade. If a 15% reserve margin is viewed as a resource adequacy target, the system has been close to dependent on import capability for resource adequacy during the winters of 2005/06 through 2007/08 and 2010/11. Without additional retirements other than Sundance 1 and 2, the currently projected load growth would erode reserve margins over the next several years in the absence of resource additions."

The intertie plays a broader role than simply balancing and load management. When properly designed, it also fundamentally provides reserve capacity, effectively displacing or deferring new capacity at the margin or extending the effective capacity of existing spinning reserves. The role of the intertie in supporting the reserve requirement is shown in Figure 2 below. When the price levels are shown for the intertie utilization by month, no significant convergence is apparent between on and off peak utilization rates (see Figure 3 below).

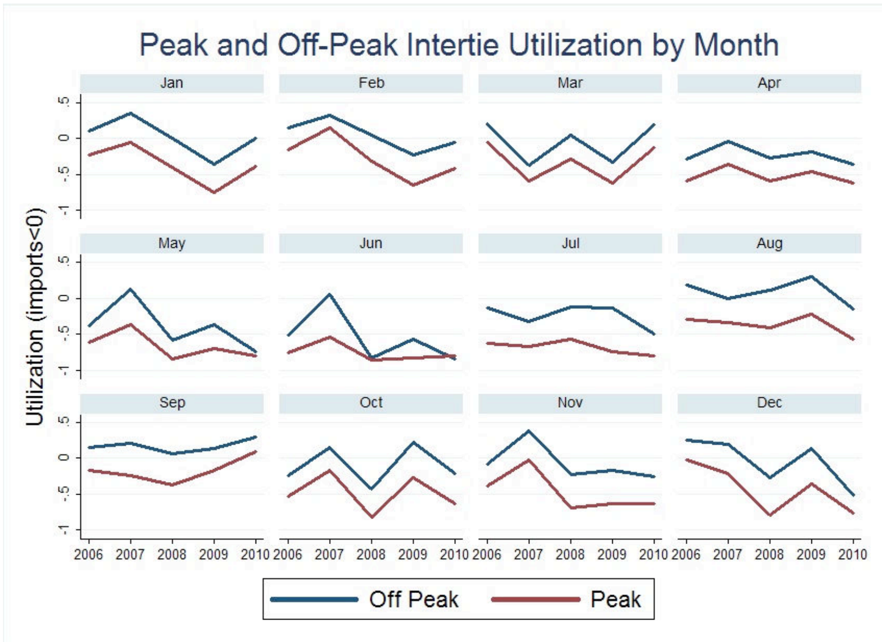
Figure 2: Interties and Reserve Margin Requirements



Sources and Notes:
Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.
Alberta Internal Load (AIL) winter peak projections for end of each calendar year are from AESO (2010a).
Unit online and retirement dates and MW rating from Ventyx (2010) and AESO (2010c); units under construction from AESO (2010d).
Projected margins represent the case in which only units currently under construction will get built and no units retire.

Source: Brattle Group

Figure 3: Utilization Rates



In their February 2011 update, the AESO noted that recent changes in Sundance I and II plants with reduced capacity foretold new reliance and operating characteristics for use of the Intertie. In their forecast they reported that changes as a result of the potential reduced capacity include:

- The forecast reserve margins reduce by approximately 7%. The new forecast 2011 reserve margin ranges between 27% and 31%. These values are similar to 2006 to 2009 levels.
- The supply cushion in the near term will be tighter, showing an increased reliance on interties during high demand, daily peak hours in the winter months of 2011 and 2012.
- The Probability of Supply Adequacy Shortfall (PSAS) Total Energy Not Served increased from 155 MWh to 1351 MWh. This new value is below the 1600 MW threshold, the point at which the AESO may take actions to bridge a temporary supply adequacy gap[11].

[11] AESO, Long Term Adequacy Metrics – Sensitivity analysis for SD 1 and 2 Termination, February 2011

Price Performance in the Alberta Market

The market design shows ample evidence of working and no obvious signs of gaming or price setting as noted in the consultant reports. A look at statistics over the past decade shows this graphically, in terms of both off and on peak pricing (Fig. 4, 5 below).

Figure 4: Pool Pricing Off Peak

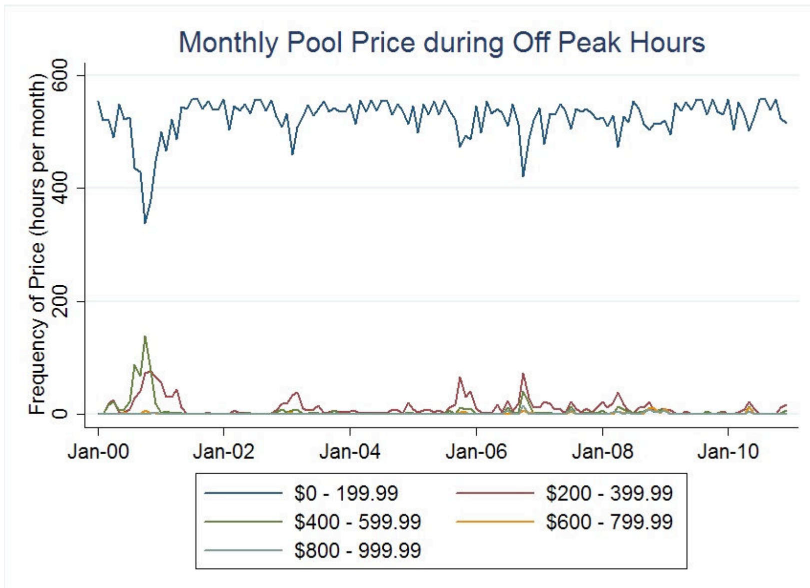
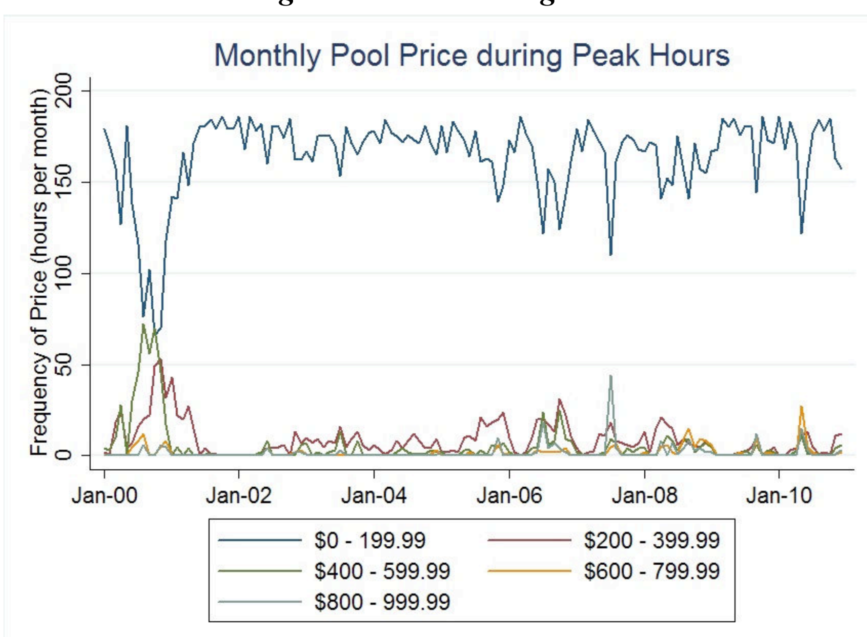


Figure 5: Pool Pricing Peak



Capacity and Balancing

As pointed out above, intertie capacity and availability serve a critical purpose, namely to balance load in regulation and to account for shortfalls that are periodic or stochastic in nature. Notwithstanding the ATC characteristics and the fact that full capacity is rarely utilized, rules and standards are in place to modulate prices and to prevent gaming or exclusion on the line favoring either imports or exports.

The AESO interprets that current governing Alberta legislation and policy does not permit for the recognition of a "first in" right for interties, but rather that there is an obligation to ensure system access service (SAS) to inject/withdraw at the border. SAS to inject/withdraw on the interties implies applying the policy and AESO obligation to plan an uncongested transmission system to 100% of anticipated in-merit generation. This is supported in sections 153 and 164 of the Transmission Regulation and 17 (c) 5 of the Electric Utilities Act. The AESO interprets that imports and exports up to the path rating of each intertie are anticipated in-merit electric energy.[12]

With regard to the impacts of either preferential access or more traditional congestion, in March of 2009, the Fraser Institute cautioned that:

> "Congestion can be costly if lower-priced electricity generators are unable to access the grid while higher-priced suppliers do so elsewhere in the network. When transmission congestion constrains power supplies, electricity generators may also be contracted to supply power under so-called "must run" arrangements in order to maintain system reliability. These orders raise transmission costs and also mean that higher-priced electricity is dispatched instead of lower-priced power."[13]

The MSA, who monitor the competitive market for abuse, feels that the current arrangement with the intertie *increases* competition and hence lowers prices in Alberta, since the generation concentration is high in the Province, encouraging each bidder to approach marginal cost in their bid. The MSA has seen no impediments to date of new generation capacity investments and as pointed out in the Brattle Report there is no evidence of generally increasing prices traceable to intertie volumes. Under conditions of non-competitive pricing, imports to the Province have the capability to depress prices, resulting in negative incentives for energy-only generation and owners.

While we do not have evidence of market power abuse or the non-competitive pricing issue cited above, the potential for these conditions to arise is a serious consideration for long term planning and operation of the system. Assumptions of supply capacity construction to meet load growth can be upset by pricing or dispatch decisions made beyond Provincial control, which creates issue of level versus non-level playing fields. The term is used colloquially, since there is no formal, rather a common usage of the term. Establishing conditions where a non-level set of market opportunities may prevail

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[12] Province of Alberta, Intertie framework October 2010

[13] Alberta Electricity Transmission Policy for the Next Generation, Fraser Institute, March 2009

should be taken into account and monitored carefully, although subtle erosion of equilibrium conditions is more likely to be the norm as opposed to sudden and dramatic market dysfunction.

III. Level Playing Field Considerations

As pointed out in the sections above, Alberta and British Columbia are functionally similar electric systems operating under fundamentally different regulatory and policy authority, rules and prescriptions. However, fundamentally the markets are different due to natural endowments and generation costs, leverage and debt protection influence of tax policy and ultimately, market risk factors.

Alberta is based on an "energy-only market" model with competitive dispatch and incentives for investment. British Columbia, as a vertically integrated and Crown controlled corporation, manages dispatch, bidding and transmission capacity based on maximizing overall corporate profit, where the shareholders are the citizens of the Province.

Absent the interties, provincial electric generation is fundamentally different as well, with Alberta dominated by thermal energy generation and British Columbia by hydroelectric facilities. These characteristics make the cost of electricity, and the subsequent influence on the investment decisions for each market different, especially when the role of the intertie is included.

London Economics[14] has illuminated this issue by referring to the initial energy "endowment" for each province and the influence of generation mix on delivered price. They state, "One of the primary drivers of rate differences is the extent of hydroelectric generation in a province. .... although Alberta is among the least well endowed with cheap resources, with only 6.5% of energy from hydroelectric generation, Alberta rates are nonetheless lower than some other provinces with more hydro".

As a proxy for the extent to which hydro endowments contribute to lower prices to final consumers, prices in the hydro-dominated Pacific Northwest, as evidenced by the Mid-C price, averaged $36.11 per MWh in 2009, while Alberta wholesale generation prices averaged $47.81 per MWh over the same period. This suggests that as much as 1.2 cents per kWh of the difference in rates between Alberta and hydro-dominated provinces may be explained by the difference in the underlying resource mix. Differences in hydro endowments may explain at least half of the difference in rates between Alberta and provinces such as Manitoba, British Columbia, and Quebec.

The London Economics study points out that this may change in the future, stating that since "shale gas has changed the dynamics of natural gas markets in North America, Alberta is favorably positioned with regards to the levelized cost of fossil fuel generating

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14 Power prices in context: comparing Alberta delivered electricity prices to other Canadian provinces on a level playing field, A.J. Goulding, I. Maher, London Economics, March 2011

capacity additions relative to those provinces which are further away from natural gas fields." This is a factor that favors future Alberta generation over that of British Columbia.

Leverage and Debt Issues

Provincial ownership and debt patterns also influence the competitive position of generators in each province. London Economics provided a comparison of the characteristics of British Columbia and Alberta in this area when they observed that Alberta was among the few provinces that did not own provincial utilities. We can argue that utilities controlled by the Crown may enjoy a distinct advantage from the so-called halo effect that emanates from the larger debt umbrella of the parent agency. In spite of some of the debate currently embroiling the world financial markets it is unlikely that the provincial parent would allow its utility to default on its debt.

The upshot is that in those markets where a utility is responsible for some explicit debt guarantee, the amounts paid for the guarantee may reflect more market confidence and will be less costly to ratepayers than those in other markets. However, looking at long-term debt to total asset ratios highlights the fact that crown utilities tend to be more leveraged than those that are investor owned.

According to London Economics, "Many provincially-owned utilities have long term debt to asset ratios of over 65%, in contrast to approximately 50% for private regulated utilities. Utilities in Alberta average 54%, and independent generators in Alberta average 61%".

They go on to observe that "while regional markets may also have other differences, such as a predominance of ratebase generation, the underlying fuel mix and supply-demand balance is a key explanator for regional price variations".

Influence of Tax Policy

The competitive stance of each electric system is influenced by their tax characteristics as well. The London Economics report points out that the difference in basic characteristics between British Columbia and Alberta highlights the fact that crown utilities have a tax "advantage" over privately owned utilities - they are tax exempt. Over the past five years the average effective tax rate for Alberta utilities was 28%. BC Hydro, in contrast, contributes a return on equity and earnings to shareholders within the Province. As well, "... provinces with provincial utilities tend to have higher corporate tax rates. Alberta has the lowest corporate tax rate in Canada of 10%".

Market Risk

A key issue for independent generators is cost recovery. Crown corporations representing BC Hydro and SaskPower face no traditional risk of cost recovery since they represent the pool of ratepayer and/or taxpayers as their investors. They have two fundamental opportunities for cost recovery, the first is from their ratepayers and the second is from export sales. In Alberta's open market, IPPs have to compete to recover their costs. There is no guaranteed recovery. In fact, Alberta IPPs have to compete against crown corporation importers, with their aforementioned cost advantage to serve their own domestic, Alberta customers.

Maintaining an open and competitive market on the broadest possible basis ultimately benefits the largest combination of producers and consumers. FERC has long recognized the need for a limit to anticompetitive behavior, and conditioning non-public utilities' use of public utility open access services on an agreement to offer comparable transmission services in return. The current rule for instance, also expands reciprocity obligations to require that non-jurisdictional utilities that are members of, or take transmission from, an RTO or ISO must provide comparable transmission service to any member of that RTO or ISO. In part this signals a need to provide equivalency in retail competition, but also to highlight the need for that equivalency to be maintained in critical transmission access across jurisdictional boundaries. FERC would argue that to be effective it must extend beyond wholesale providers and must include municipal as well as merchant resources.

IV. Issues for the Alberta System

Maintaining, expanding or adapting new rules for use of the interties is a public policy concern that is shared by all the jurisdictions involved in its use. However, certain elements or caveats are worth establishing, albeit in the context of two energy systems that are dissimilar in authority, intention and practice.

Three key areas, mentioned in the introduction, must be addressed in the context of current intertie use, as well as the need to look forward to impacts on capacity additions in Alberta if intertie capacity is expanded in the future. Leaving aside the engineering issues, these are:

- Economics and Consumer Pricing
- Market Power and Competition
- Investment Incentives short and long term

Economics and Consumer Pricing

According to Brattle, "Price suppression in Alberta's energy-only market through expanded interties is likely to be magnified by an increase in imports from zero-marginal-cost technologies, such as new wind generation. However, according to the reports we have examined, current intertie use patterns *do not appear* to have a significant impact on end-user pricing. This is most likely due to surplus domestic capacity beyond demand, in spite of the ATC limitations. However, there could be economic effects if future intertie capacity is increased favouring on-peak British Columbia power, or if older generating capacity in Alberta is retired. The practical impact of this outcome would be a re-iterative trend that could effectively diminish the attraction for new generating capacity in Alberta. In addition, other issues may emerge when *future* alternative generation such as wind in BC is considered in the overall energy mix, effectively competing with established generation.

In short, there are a host of reasons why import behavior from British Colombia, Saskatoon and Montana could in certain circumstances be intrusive or effectively non-competitive. These include the potential for strategic withholding or pricing, more competitive access to capital or the indirect effect of depressing interest in investments in the Alberta market if more inexpensive import power is available for dispatch within the AESO system.

The source of potential concern may be found in the lower operating costs of BC-based power (this is potentially true for Sask power as well, should there be future capacity available in their market area), including lower effective tax rates that reflect a direct subsidy from taxpayers to ratepayers.

For example, the Montana Alberta Transmission Line (MATL) developer has predicted that adding the new transmission line will allow for the development of a large wind farm at its source in Montana. Similarly, increased intertie capacity with BC Hydro will interconnect Alberta more heavily with a market that is anticipated to become a large exporter of green power, likely from wind and hydro, which could further depress Alberta electricity prices via imports because of lower prices in British Columbia.

Importantly, additions of wind power in British Columbia come in response to calls for tender, with long-term Power Purchase Agreements provided to the winners of those calls. Those PPA's provide BC wind producers with full cost recovery and provide BC Hydro and its export arm, Powerex, with energy to sell, when it is surplus to domestic needs.

When Powerex sells into Alberta's market it can not only recover the[15] marginal cost of its production, but in periods of Alberta power scarcity, it can extract rents from Alberta consumers. With this arrangement, BC Hydro effectively has two opportunities to recover its capital costs; once from its ratepayers and a second from Alberta consumers. In contrast, Alberta IPPs have no access to a PPA backstop, they have to secure such contracts in competition with other suppliers or recover their costs from spot market sales.

These low marginal-cost imports could directly benefit Alberta customers in the near term. However, in the long term, there is the potential for price suppression to reduce the profitability of generation resources in Alberta, which would make it less likely that new resources would be built while increasing the likelihood that existing generators would retire prematurely. The upshot in the meantime is a tendency to reduce the reserve margin within Alberta and make the system more dependent on the interties for resource adequacy[16].

We expect prices in a well-managed system to reflect replacement costs, regardless of the presence or capacity of robust interties in absence of policy directives to the contrary. Expanding import capacity where consumers price reductions or artificially stable levels[17] can prove a short-term benefit. Intra-Alberta supply may be deferred as a result by new import volumes until the point where prices ultimately reflected replacement cost. This is a policy issue that ultimately concerns a choice of supply based on reliability standards and expectations regarding sources which may ultimately have their own supply / demand imbalance issues to deal with.

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[15] The potential for market power abuse was dramatically demonstrated by recent action by the Market Monitor against TransAlta which controls approximately 16 percent of Alberta's wholesale power, who admitted to at least one instance of blocking intertie power transfers from British Columbia in November of 2010, which created artificial signals of power scarcity. This instance of increased and unreasonable power pool costs may have been repeated in other instances and underpins our assertion that manipulation of intertie capacity is possible; however, details or data that might document this or other instances were not available for this research.

[16] Brattle Group, Ibid.

[17] The poster-child for this effect is the 1998 California restructuring plan, enabled by AB 1890.

Market Power and Competitive Conditions (Level Playing Field)

Generators in Alberta have asserted on occasion that there is a need to maintain a "level playing field" in terms of competition within the Alberta market and in terms of access to transmission facilities, not only within the Province, but regionally in the context of the two neighboring provinces which have fundamentally different ownership and taxation rules for energy facilities.

There is no technical definition for level playing field; however, there is a general understanding of the concept that suggests fairness in opportunity for market participants, including information flows and transparency, an inability of any one participant or collaborative to make the market either through direct price manipulation or withholding capacity or production and equal access to transmission or movement. Effectively, the market is level if there is no external interference that limits the ability of any player or group to compete fairly which does not mean a prohibition against opportunities to collect scarcity rent from locational or time advantage.

A simple comparison will serve to make the point regarding the opportunity to collect scarcity rent during high demand periods. In this example, without import capacity, prices would periodically reach the cap, which is set in order to reflect scarcity characteristics, and bound excursions, sending a clear investment signal for new capacity. This signal would reflect the full cost of power generation rather than other marginal calculations such as the cost of co-generation that does not reflect full plant overnight and marginal costs of operation. However, its not just investor risk that is at issue here, its consumer risk if they pay too little early on (i.e. not the appropriate amount to cover costs), since they will be left with too little capacity later on.

As the Government has pointed out in its Policy Framework, having a robust intertie improves the functional flexibility of the system operator, and can act as a dynamic signal for competitive cost pricing. However, the intertie has the *potential* to be used as a restrictive economic instrument affecting intra-Alberta bids and signals that could ultimately threaten the overall stability of supply adequacy in the Province.

Conditions of strictly level or egalitarian conditions are likely to be fluid or dynamic in the best of cases, with unique opportunities or timing available to various market participants at irregular times. We assume that systematic opportunism at the expense of other players or exerting market power will be curbed by regulatory authorities.

Following Alberta's deregulation, institutional expertise has been developed in former generation companies that we assume transferred to spun-off or newly competitive entities. This can be expected in any market but does not indicate or foreshadow collusive or anti-competitive behavior, rather it may highlight the most aggressive or market-savvy participants in terms of meeting market demand. When the total number of market participants is not large, as is the case with most natural monopolies such as electricity generation and distribution, it may appear that there will be oligopolistic and coordinated behavior, resulting in excessive price levels. Similarly, there can be subtle signs that new entrants to the market place are discouraged by forecasts of insufficient returns to capital or price levels below average marginal cost. In these cases, there is an important role for public regulators to objectively and consistently apply rule sets that limit excursions or gaming that threatens long term market cohesion.

There are basically two variants on designs to create or maintain a level playing field.

- Rules-based level playing field: Here all firms in a market are treated the same in equal circumstances with regard to legislation, taxes, subsidies, et cetera.
- Outcome-based level playing field: All firms in a market have the same expected profit. This means that, in case firms are heterogeneous, the government compensates the disadvantaged firms (for instance with subsidies). This may be the case where less-competitive industries such as solar or wind producers are desirable but not yet market competitive.

The Province embodies a rules-based system that implies that a level playing field is desirable for example, the Payment In Lieu of Taxation and the S. 95 provisions in the *Electric Utilities Act* of 2003. In this context, we opine that it is never desirable to pursue a fully outcome-based level playing field, especially in a commodity market, but may be desirable to intervene periodically in the market to a certain extent in order to avoid market failure. In case of market failure it is preferable to use symmetric rules (equal for all firms), instead of asymmetric rules (favouring some firms or with inconsistent enforcement). In general a 'level playing field' is desirable, but the definition or equilibrium evidence for it may be elusive. This suggests that achieving the twin goals of adequate and affordable capacity over time while avoiding market power abuse demands dynamic efficiency, enforcement and reevaluation of market participant behavior.

A recent filing by Morgan Stanley on the issue of the Application to Amend BC Hydro's Open Access Transmission Tariff (OATT) provides a useful discussion on the issue of whether current business practices and existing market design are open and competitive in terms of allowing the intertie to be used for its intended purpose, namely to act to balance demand and supply between the two provincial systems.

To put this in context, Morgan Stanley point out that "the underlying purpose of the OATT is to ensure that all interested market participants can compete fairly in energy and related markets that require use of the BC Hydro Transmission System. When the Transmission Provider (or an Affiliate) is also a market participant (as is the case with the reintegration of BCTC and BC Hydro), there are many ways that the Affiliate might be able to benefit from its relationship to tilt the "playing field" in its favour"[18]. They point out that the proposed methodology, with the "allocation of a portion of BC Hydro's PTP charges to Powerex does not in the normal course affect BC Hydro's rates to its bundled service customers, but does serve to provide both BC Hydro and Powerex with economic price signals regarding their use of the BC Hydro transmission system." One outcome, according to Morgan Stanley is that Powerex, acting on behalf of British Columbia

[18] Letter of Comment on OATT Application, MSCC, 2010

citizens is only allocated a fraction of the total point-to-point transmission charges while outside agents such as Alberta, are charged the full amount.

This is in contrast this with the Alberta market, where there are no transmission rights. Transmission is provided to all generation that is 'in-merit'. One distinction in treatment between imports and intra-Alberta generation is the application of an import opportunity service tariff and the provisions in operating rules that imports be cut first in cases of domestic emergencies, but this latter treatment is common to imports in all markets in general.

Investment Incentives

Alberta's energy only market has been successful in meeting demand and creating adequate reserve capacity. As discussed in both the London Economics and Brattle Group reports, the result has been competitively priced electricity for consumers and a reasonable investment signal. The issue of province-wide transmission capacity has been arbitrarily dealt with by the Government and the Alberta Utilities Commission (AUC); the upshot is likely to be increased prices for consumers (see Bill 50 analysis[19]) but reduced congestion intra-provincially.

However, as pointed out in the consultant reports cited above, uncompetitive priced electricity on the existing intertie or on an expanded intertie in the future, could forestall timely investment in the Alberta market, effectively shifting supply to either British Columbia or the US via existing north south interties.

[19] Transmission Policy in Alberta and Bill 50, J. Church, W. Rosehart, J. MacCormack, School of Public Policy, University of Calgary, 2009

V. Conclusions

Alberta's commoditized market requires a rules-based level playing field to ensure no unfair advantage and to remain attractive to investment. Rules have been applied to intra-Alberta government owned entities, but there do not appear to be similar rules to govern imports, including those from regulated markets and from markets with different design (MID-C) where cost recovery risk, leverage, debt backstop, or reciprocal access to consumers, is not the same as it is in Alberta. Our conclusions regarding market issues and the concept of a "level playing field" follow.

The Current Market Design

Over time, access to electricity is considered more and more of a common-pool good; that is, citizens in a modern society should not be denied access to that good at a fair and reasonable price.

The current Alberta electricity market reflects a conscious effort to create an efficient and transparent energy-only market that will grow with demand over time and provide the most appropriate price levels for consumption. In the current real-world context, however, this type of arrangement is constrained in the sense that it must operate in competition and cooperation with nearby monopoly markets. In contrast to Alberta, neighbouring regulated crown corporations have the capability to develop risk-free investments. They are guaranteed cost recovery from their captured ratepayers. Those utilities enjoy lower financing costs, derived from government ownership and do not pay taxes, in contrast to Alberta generators.

BC exporters can exploit an opportunity to recover capital cost twice, once from their domestic, ratepayer and the second time by the margin embedded in the clearing price for power sold to Alberta. One outcome of this is the incentive to build capacity to supply Alberta as ties permit. Consequently, the Alberta market is not a pure and insulated energy only market where signals are derived only from consumer demand, regulator incentives and approval and investor interest as well as policy directives from other provinces that are outside its jurisdiction of influence.

The current transmission arrangement in the Province provides incentives to use the tie capacity temporally or strategically to create an outcome that benefits local customers in a short time period over the longer and more sustained market design period. While this may be overcome with new investments, the short-term outcome *can* be detrimental to clear investment signals.

In contrast, an absence of continuous or adequate transmission capacity can lead to locational or even regional price and ultimately capacity dislocation. In this case, the IPP's technically have an oligopoly but do not exhibit collective withholding behavior. We see no reason to use tools like import bids from the tie to "break up" the oligopoly, as it alone does not pose a risk to the long-term health of the provincial generation system. There is a risk in allowing out of province generators to become equal competitors and influence investment decisions indirectly in the province without rule or price based regulation over the long term.

We believe that the system design for Alberta offers transparency and resilience that can develop adequate capacity over time, sufficient to match load growth. Ultimately, price should reflect replacement cost of intra-Alberta supply. However, this system design can be threatened by a dependence on or misuse of neighboring generation systems. The MSA has stated that they believe that out of province participants are important contributors to (system) efficiency and should be judged on the same standard as in-province generators. They note in their guidelines that importers should be treated as supplier-on-supplier competitors. We note, however, this would really be true only if out of province bidders using the intertie had the same market characteristics or bidding behavior as Alberta generators.

Given the demonstrated need for this capacity over time (although not a clearly demonstrated need for additional capacity at this point) the utility of the intertie seems well established within the operation of the Alberta market. In addition, we do not find that the exporter (British Columbia) is strategically offering generation via the intertie in quantities or at times sufficient to distort the Alberta price level at this time.

On this point, the Alberta government via its Electricity Policy Framework, has stated that import capacity should be offered at a market price level that should not take advantage of their tax status as a government monopoly (this type of treatment is already applied to Medicine Hat within the province).

The Electric Utilities Act cites under Section 5(c) the need to
"provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant".

If implemented, this policy supports the goal of achieving the most competitive and transparent[20] market possible that is based on consistent long-term integrity of the price signal. The Government cites this objective in the 2005 Electricity Policy Framework when they state that requiring imports to offer at zero distorts the overall market. The result is a long-term structural risk in achieving the core goal of an energy-only market, namely adequate and timely development of new capital facilities. This is only possible in this type of market when price approximates long run marginal cost that in an efficient system should reflect the replacement cost of capital. Since imports may act to set the price at the margin in cases where they bid >0 or at MC, it is reasonable to expect them to offer MC instead of zero or otherwise distort their price characteristics.

[20] Transparency for competitors in bidding, consumers and investors for long term capacity additions

A side benefit of importers offering price is a potential increase in overall revenues distributed throughout power producers in the fact that pay as bid behavior results in higher average payments to pool participants who will bid closer to or at MC.

The Outcome of substituting import zero bids for pay as bid

The current tieline policy arrangements reflect a desire to achieve the lowest cost in Alberta, which is laudable but may distort the long-term capital risk and investment characteristics of a market that must survive with minimal import support over the long term. For instance, when importers bid zero then import volumes are matched to the current void or deficit, whether artificial or not. The result is that some internal generation may be effectively priced out of the market (low) and not recover costs for either running or being available at the time. In the short term, a consumer might argue that price is more competitive (cheaper), but the upshot is a long-term distortion of the price/investment signal. This does not suggest that British Columbia cannot be an equal or equivalent bidder under a common pricing or bidding strategy that is open and competitive; the requirement to bid less than MC can have an impact on investment and capital replacement in Alberta long term.

Price signals for investors

There is a risk that increases in tieline capacity could result in an erosion of the price signal for investors, leading to a lack of or mistiming of new investment, since there would effectively be no hours of scarcity. The current intertie rules are primarily concerned with mitigating the possibility of high prices and market power rather than addressing a situation where prices were actually too low. Currently import capacity is tied to our ability to withstand and control loss of the tieline capacity when maximum imports are demanded. Contracting more interruptible loads rather than simply increasing capacity on the tie offers an alternative to this strategy without putting new capacity development at risk.

System Design and Market Risk

In Alberta, the market is designed to reflect investor "risk" in meeting long-term capacity, technology choice and fuel price choices. This is in contrast to a Province such as British Columbia where the risk of system investment is borne broadly by all constituents. This is often used to contrast the risks of system performance where all taxpayers in British Columbia (as opposed to all ratepayers which includes industry as well) share the risk and reward of power generation, and only those participating generators or their shareholders are responsible for risk in Alberta. In fact, the ratepayers in Alberta bear the risk of insufficient market performance indirectly, since a substandard or insufficient generation mix could result in higher prices, lower or interrupted levels of service.

A key difference in this context is the ability of the Government of a Province like British Columbia to act as a non-regulated market participant, and potentially game the system. Even in the absence of this type of directed behavior, the existence of unregulated or less-than-competitive power can upset price and investment signals when used by internal market participants. An example includes the opportunity to reserve import capacity in time blocks that effectively preclude intra-market bids from recovering MC.

In summary given the materials available to us, we conclude that there is not a "level playing field" currently with regard to how imports interact within the Alberta market against intra-Alberta generation.

This is true for a combination of reasons including the nature of the generation base in BC, costs of environmental compliance, new capacity addition delays in Alberta and the ability of BC to effectively load their interties at critical times. However, this issue is primarily one for future consideration, since there does not appear to be evidence of market power abuse at the current time or more importantly, interruption of or interference with efficient commodity trading. The potential for both of these conditions exists (and the market monitor is aware of them) so as a consequence, this report should serve as a cautionary note, signaling that the potential for capture exists and should be dealt with before approval of new line capacity in the future.

Solutions such as pay as offer[21], or increased transparency in transmission commitments that would prevent tie-ups of capacity, for instance in time-sensitive "loading" of the interties so as to economically encourage Alberta to curtail native dispatch[22] or locking in capacity to accommodate wheeling to US markets are illustrative of tools that would accomplish this without distorting market operations or prevailing against core policies that underlie the different ownership and dispatch protocols of each Province. Additionally, Morgan Stanley raises 3 points in their letter to the BCUC that the rates charged for the incremental use of the transmission system should reflect actual incremental costs. As they point out, this would offer further competitive opportunities for Alberta IPPs to enter the export market to BC. They also suggest formally limiting the capacity on the tie lines to a maximum of 20% or 100 MW for any individual company. Ultimately this would put more line capacity in competitive play, and discourage any player from effectively capturing all available line capacity at high value hours.

As a policy matter, however, and in the interest of commenting on the value of a "level playing field, the last comment advanced by Morgan Stanley is perhaps the most compelling. If the intertie is to benefit both parties equally, and be divorced from other considerations of electric operations within each Province, then a policy of non-discriminatory, open access with a common Transmission Service tariff for all parties should be the rule.

[21] Bahry note to AESO, May 2011
[22] see Morgan Stanley letter pg. 6, para. 3

Appendix A - Alberta Energy Market

Alberta Generation Characteristics

Generation

Current generation capacity is 13,535 MW, with a maximum of 900 MW in additional capacity through the BC and Saskatchewan interties. Generation, as of 2011, by fuel type includes:

coal	44%
natural gas	41%
hydro	7%
wind	6%
alternative	2%

There are currently 164 participants in the generation market. Average hourly load in 2010 was 8,188 MWh, and average peak demand in 2010 was 10,225 MWh.

Transmission

The high voltage transmission lines are owned by Transmission Facility Owners (TFOs). There are six TFOs in Alberta who own and operate transmission lines in six separate areas of Alberta.

Distribution

Distribution wires remain regulated in Alberta. Consumers have the choice between a regulated rate (set by the Alberta Utilities Commission) or a market rate for electricity provided by an unregulated "energy marketer."

The Regulatory Process

Electricity prices are competitive and are set by daily and hourly market bids from participants; bids and capacity are influenced to a minor degree by access to intertie capacity (see Brattle Report). The Alberta Utilities Commission sets the tariff for transmission access, in a multi-stage process. The first stage determines the revenue requirement for TFOs to operate and maintain the transmission system in Alberta. The second stage determines the revenue requirement for AESO (prudently incurred costs) to manage the transmission system. The TFO revenue requirement is then rolled into the bundled AESO charge.

This last stage determines the allocation of costs between different classes of customers for system access by the AESO, and determines the rates charged to customers to recover the revenue requirement.

The Alberta Utilities Commission that must approve any future intertie expansion regulates the cost of delivering electricity to the consumer via the distribution system.

Price and Cost of Energy

Market participants (Alberta producers and importers) "offer" a volume of electricity at a specified price, which includes capacity and the time required to ramp up production to the System Operator. Demand "bids" are submitted by exporters and wholesale consumers, which includes a stated intention "not to purchase" above a specified price. There is a distinction between 'offers' and 'bids', referring to supply and load participation respectively.

Schedulers rank supply offers and demand bids from the lowest to highest price for each hour of the day, creating a "merit order" for electricity dispatch. The system controller maintains balance throughout the day by dispatching from the merit order. For each dispatch minute, the last eligible electricity block dispatched by the system controller sets the System Marginal Price. At the end of each hour, the time-weighted average of the system marginal price is calculated and published as the pool price. Delivered electricity is financially settled at the pool price. By design, importers are restricted to bidding $0, as is wind, while producers intending to export bid at $999.

Alberta Interties

The Alberta electric system currently has two major interties, one with BC Hydro and the other with Saskatchewan. The Alberta-BC intertie consists of one 500 kV circuit and two 138 kV circuits. The current maximum total transfer capacity for imports from BC is 780 MW, and 800 MW for exports. The Alberta-Saskatchewan intertie has a maximum total transfer capacity for imports and exports of 150 MW. The north-south intertie is the Montana-Alberta Intertie, a 230 kV line used primarily for balancing load[23].

[23] a recent AESO report notes this intertie is not expected to increase net import and export limits between Alberta and other jurisdictions

Appendix B - British Columbia Energy Market

Generation

BC Hydro operates 30 hydroelectric facilities and three natural gas-fuelled thermal power plants. BC Hydro produces between 43,000 and 54,000 GWh of electricity annually.

There are currently 47 operating IPPs within British Columbia, 32 of which are run-of-river. Similar to Alberta, but on a smaller scale, provincial independent power producers own their own transmission *interconnections* linking them to the BC transmission grid. These independent producers are considered public utilities under the Utilities Commission Act and are exempt from price regulation by Ministerial Order. The BC Utilities Commission regulates the contracts that IPP enter into with electricity distribution utilities.

Transmission & Distribution

With the exception noted above, transmission and distribution lines are owned and operated by BC Hydro. The BC Hydro Public Power Legacy and Heritage Contract Act ensures that electricity assets, including transmission and distribution lines, must remain publicly owned.

Regulatory Process

BC Hydro falls under the regulatory jurisdiction of the BC Utilities Commission. The transmission revenue requirement consists of three parts: a BC Hydro revenue requirement; asset management and maintenance revenue requirement; and BC Hydro Owner's revenue requirement.

The Utilities Commission determines "just and reasonable" rates to be charged by BC Hydro to BC customers. This does not mean that imports and exports are charged at regulated rates for energy. BC Hydro's revenue requirement is based on recovery of the cost of service associated with the provision of transmission services. The transmission tariff is set by the Open Access Transmission Tariff (OATT), and is based on cost of service. The OATT sets out the terms and conditions by which BC Hydro conducts business with customers.

The rate schedules attached to the approved tariff outline the prices for transmission services purchased from BC Hydro. The owner's revenue requirement consists of transmission costs incurred by BC Hydro related to asset ownership, operating expenses associated with property services and aboriginal relations and an allocation of BC Hydro corporate costs, off-set by non-tariffed revenues and recoveries.

Appendix C - Potential Market Power Abuse

adapted from Morgan Stanley

In a given hour, Powerex can import on one tie-line using Network Economy and simultaneously export on the other tie using Firm Transmission purchased by BC Hydro. When this is done, there is no charge to Powerex because there is no net change in the Trade Account. In addition, Powerex is now only charged the hourly discounted rate for transmission when it is actually used, and does not pay for any unused capacity. Because of this, when Powerex submits transmission requests on behalf of BC Hydro, it has every incentive to request all available capacity in both directions on both interties, since it has no costs if that capacity ends up unused.

There are two inappropriate consequences from this situation. First, any unaffiliated party that makes a similar request, and is successful, will have to pay the full transmission costs for any unused capacity. Second, Powerex's ability to make such requests and be awarded 100% of the capacity removes that capacity from the market, blocking out competitors that would like to acquire it. This is anti-competitive on its face, undermines the spirit of FERC reciprocity rules, and also frustrates explicit provincial policy to maximize power exports from BC to other jurisdictions.

A recent example was a BC Hydro (through Powerex) purchase of 120 MW of non-firm transmission to Alberta for 11 months (BCTC TSR 74742399). A reasonable expectation of the usage rate of this capacity is 10-20% based on historical transmission availability (see the attached Appendix A). For the calendar year 2009, the actual availability for this transmission was 16%. The cost of this transmission was nominally $5.40/MWh, yet under the revised transfer price agreement, Powerex is only required to pay for this capacity when it actually uses it to move power, and pays charges of $3.00/MWh on-peak. The full cost for this transmission reservation is $5.2 million dollars.

However the cost to Powerex, taking into account the usage (16%) and the discounted rate ($3.00), is only $460,000. Powerex is able to tie up this capacity so no one else is able to purchase it and can use it to capture periodic high priced markets in Alberta, but Powerex does not face the reality of paying for the unused hours.

In any hour when Powerex is simultaneously importing from the US or purchasing from an IPP in BC, there would be no change to the Trade Account volume and there would be zero cost allocation. Powerex has effectively tied up all export capacity to Alberta for free. Furthermore Powerex is not assessed for losses or any other charges for Scheduling, Dispatch and Ancillary Services. A nonaffiliated competitor, however, which was successful in purchasing the same non-firm capacity, would be required to pay the full tariff price of $5.40/MWh every hour plus Scheduling, Dispatch and Reactive Fees of another $.96/MWh, regardless of whether or not it actually scheduled and moved any power. So, assuming a 16% actual usage rate, the de facto cost to a non-affiliate for each

MWh actually moved is $40 per MWh. Additionally, the non-affiliate is required to pay for losses, and has additional costs for moving the power to the intertie, whereas Powerex does not pay for moving power within or across BC Hydro's system under any of the OATT Rate Schedules. Clearly, unaffiliated power marketers have no realistic ability to compete with Powerex under these terms.

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