

# **Is BC a Net Power Importer or Exporter?**

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## **Introduction**

On April 28, 2010, the province of British Columbia introduced the Clean Energy Act. While the purpose of the Act has many repercussions for the provincial electricity sector, one of its primary objectives is to create and promote opportunities for energy exports. As the government's background document to the Clean Energy Act states: "in addition to supplying domestic needs [the province will] work in partnership with renewable power producers to actively seek opportunities to sell clean, reliable electricity to neighbours in Canada and the U.S." (Government of British Columbia 2010, p.1). Yet, substantial controversy appears to surround the viability of British Columbia's electricity system. One side argues that BC already has abundant energy resources and uses them to generate sales in lucrative adjacent markets. The other side says energy demand in BC is growing so quickly that it has already outpaced the province's ability to meet it, with the province forced to purchase electricity from adjacent markets. Which of these stories is true? The short answer is both and neither.

The question of whether British Columbia is a net exporter or net importer of electricity is misleading because any answer fails to tell the full story. It is necessary to distinguish between revenues and volumes when assessing whether the province is a net exporter or net importer. In this regard, one also needs to distinguish between the capacity to generate electricity and actual power production.

## **British Columbia's Electricity Infrastructure**

BC Hydro is the single largest entity in BC's electricity sector and the third largest utility in Canada. The crown-owned corporation serves 94% of the province's population. BC Hydro's franchise area is the entire province of British Columbia, but excludes the area serviced by FortisBC, which is a regulated public utility that operates in the province. FortisBC's transmission system connects with BC Hydro to form an integrated provincial electricity grid.

But FortisBC is not the only player in the provincial system.

Nelson Hydro operates generation, transmission and distribution facilities for the City of Nelson. The cities of New Westminster, Grand Forks, Kelowna, Penticton, as well as Summerland Power and Hemlock Valley Utilities, distribute power to their customers after purchasing electricity from BC Hydro or FortisBC.

In addition to publicly-owned generation facilities, independent power projects (IPP) have been and are being built and operated by private firms. Teck Cominco Metals Ltd. is an international mining corporation operating in British Columbia that owns the Waneta Dam near Trail on the Pend d'Oreille River, just before it enters the Columbia River. The dam was completed in 1954 to provide power to the company's smelter and has a generating capacity of 450 MW; there is a (2009) proposal to expand the Waneta's generating capacity by 335 MW.<sup>1</sup>

Rio Tinto Alcan owns the Kemano hydroelectric facility on the Nechako River, a tributary of the Fraser River, and the accompanying transmission assets connect the company's aluminum smelter at Kitimat to BC Hydro's grid. The Kenney dam was completed in 1954 and has a generating capacity of 896 MW.

BC Hydro manages the largest share of the provincial capacity, although generation by independent power producers (IPPs) is growing in importance. British Columbia is able to sell and purchase power in adjacent markets due to interconnections with Alberta and the United States. BC's grid is linked to Alberta via two 138 kV lines and one 500 kV line. Two 500 kV lines and two 230 kV lines connect BC to the U.S. Complicating the supply picture are the flows of 'Treaty power' that were negotiated through the Columbia River and Skagit Valley Treaties, plus the Libby Coordination agreement.

### *The Columbia River Treaty*

The Canadian side of the Columbia River originates in British Columbia, Montana and Idaho, and, after leaving Canada, flows through Washington and Oregon into the Pacific Ocean. The Columbia River Treaty was negotiated between Canada and the U.S. during the period

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<sup>1</sup> See <http://www.columbiapower.org/projects/wanetaexpansion.asp> (viewed June 8, 2010). Teck sold one-third of its interest in the Waneta dam to BC Hydro for \$850 million as of March 5, 2010. This represents Teck's historical surplus generation that was sold to BC Hydro. Teck also owns 15 km of transmission line connecting its BC operations to the United States.

following major flooding on the Columbia River in the U.S. in 1948; the Treaty was signed in 1961 and ratified by Canada in 1964.<sup>2</sup> It resulted in the construction of the Duncan (1967), Hugh Keenleyside (1968) and Mica (1973) dams in BC and the Libby Dam (1975) in Montana on the Kootenay River – a tributary that accounts for 20% of the water in the to the Columbia River leaving Canada. The purpose of the Treaty was primarily flood control, but the operation of the Canadian dams increased power generation in downstream dams, with half of this additional electricity and half of the power output from Libby Dam allocated to BC. As part of the Treaty, a Pacific Northwest-Southwest intertie was also built to transfer BC's share of this electricity to California. The Treaty obliges BC to operate the Mica, Arrow and Duncan dams for the purpose of flood control benefitting the U.S.; thus, BC cannot operate its reservoirs in a way that would adversely affect the stream flow of the Columbia River in the U.S.

In 1977, BC Hydro installed a powerhouse at the Mica dam with a capacity of 1792 MW – the only Treaty dam to produce power within a few years of construction. In 2003, a powerhouse with a capacity of 185 MW was built at the Keenleyside Dam. Further, although not mentioned in the Columbia River Treaty, the developments on the Columbia River facilitated construction of the Kootenay Canal Plant (1975) and Revelstoke Dam (1984), located between the Keenleyside and Mica dams just north of the town of Revelstoke. After recent upgrades, the Kootenay Canal Plant has a generating capacity of 580 MW, while the Revelstoke Dam has a generating capacity of 2480 MW (after the addition of another 500 MW unit in 2010).

### *Libby Coordination Agreement*

The Libby Coordination Agreement was negotiated in 2000 resolving a dispute between

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<sup>2</sup> The federal government negotiated the Treaty on behalf of the province of British Columbia, which assigned the task of constructing and operating the Treaty dams to BC Hydro and the power generated in the U.S. that is allocated to BC to BC Hydro's marketing subsidiary, Powerex. A history of the Columbia River Treaty, including the controversies and its costs and benefits is available at (viewed June 7, 2010): [http://www.empr.gov.bc.ca/EAED/EPB/Documents/History%20ofColumbiaRiverNov139web\).pdf](http://www.empr.gov.bc.ca/EAED/EPB/Documents/History%20ofColumbiaRiverNov139web).pdf).

BC Hydro and the Bonneville Power Authority (BPA)/US Army Corps of Engineers.<sup>3</sup> The agreement allows the Corps of Engineers and BPA to spill water for in-stream purposes, namely, to protect the endangered Kootenai sturgeon. This water is not used to generate electricity, thereby reducing the overall power generated in the system and reducing the power that would otherwise accrue to BC. The agreement enables spilling of water for in-stream purposes without reducing the power benefits that British Columbia is entitled to under the Columbia River Treaty.

### *Skagit Valley Treaty*

The Skagit Valley Treaty (1982) came about because Seattle wished to raise the height of the Ross Dam on the Upper Skagit River in Washington, which would raise the level of Ross Lake. Ross Lake straddles the international boundary and Canada opposed raising the lake level, because this would reduce the generating capacity of BC's Seven Mile Dam (1979), which is a run-of-river facility. The agreement requires that BC Hydro deliver the equivalent of 35.4 MW of capacity to the Seattle load centre at prices to be determined through negotiation.

## **Generating Capacity vs. Power Production**

To determine whether BC is a net exporter or importer of electricity, it is important to distinguish between generated power (energy) and generating capacity. Generating capacity refers to the full-load continuous rating of a generator, also known as the nameplate rating or maximum continuous rating (MCR). Thermal generators are able to provide power consistently near to their MCR because of the constant and unvarying fuel supply. The electricity that is generated from renewable energy technologies depends on the availability of the fuel source, whether it is water, wind or sun. Hydroelectric units are reliant upon sufficient water inflows and, even where they are supported by reservoir infrastructure, reservoir levels (also known as

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<sup>3</sup> The Bonneville Power Administration is a U.S federal energy agency in the Pacific Northwest. BPA markets wholesale electrical power from 31 federal hydro projects in the Columbia River Basin, a non-federal nuclear plant and several other non-federal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. BPA also operates and maintains about three quarters of the high-voltage transmission lines in its service territory of Idaho, Oregon, Washington, western Montana and parts of eastern Montana, California, Nevada, Utah and Wyoming.

elevations). Treaty and in-stream environmental considerations, such as flood control and fish habitat, affect the dam owner's ability independently to manage these elevations. Thus, the power output from hydroelectric generators may vary significantly from their capacity values in any given hour, day, month, season and/or year.

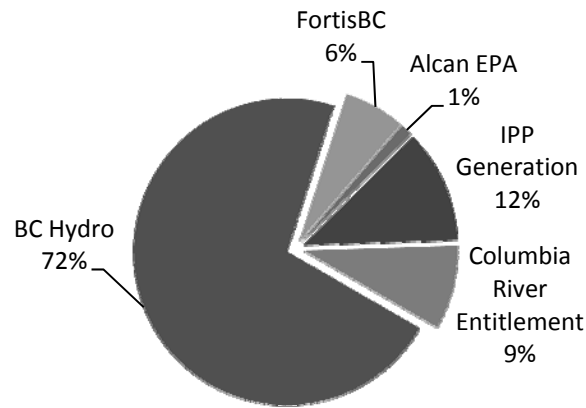
Independent power projects with a variable fuel source are likely to have an even greater discrepancy between capacity values and energy output (BC Hydro 2010a). Run-of-river hydroelectric generation uses only the actual flow of water to generate electricity; there is no associated water storage capability. Wind energy output will also be less than its installed capacity value, as power is produced only during periods of sufficient wind. If the wind is too strong, wind turbines are required to shut down due to safety concerns, while too little wind will not enable power production at anything near a turbine's generating capacity (or may even result in zero output).

### **Capacity vs. Peak load**

When the BC electricity system was built, the additional cost of adding turbines to large-scale dams was relatively small; it was rather easy to add capacity. Even though not all dams constructed under the Columbia River Treaty initially included generation facilities, British Columbia nevertheless purposefully overbuilt the electricity system's capacity relative to immediate and foreseeable demands. Excess capacity continues to exist even today. As of 2010, excluding the Burrard thermal plant,<sup>4</sup> we estimate that the province of British Columbia has some 13,250 MW of generating capacity. Total generating capacity is comprised of 9,491.8 MW of BC Hydro capacity, 850 MW of FortisBC managed hydro capacity and 1,578 MW of existing IPPs. Further, Rio Tinto Alcan can provide 162 MW of net-to-grid power from its Kemano facility under the Alcan/BC Hydro 2007 Long-Term Electricity Purchase Agreement (LTEPA). In addition, the Columbia River Treaty provides British Columbia a capacity equivalent to 1,170 MW of installed generation. The composition of currently available capacity is shown in Figure 1.

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<sup>4</sup> The Burrard natural gas plant is a peaking plant that was used in rare times when (peak) demand and export commitments happen to exceed immediate generation. On October 28, 2009, BC Ministry of Energy and Mines announced that the Burrard plant would be used to provide electricity to the grid only in cases of generation and transmission outages.



*Figure 1: Composition of currently capacity available to meet total provincial electricity demand. Total Generating Capacity: 13,250 MW*

In the future, BC Hydro (2008a) is planning an upgrade the Mica dam site with two turbines providing an additional 1,000 MW of capacity, and 500 MW was recently added to the Revelstoke Dam (and not included in the above figures). Provincial capacity will be further supplemented when projects from BC Hydro’s Clean Power Call become operational. BC Hydro anticipates approximately 1,116 MW of renewable energy projects will be constructed by the selected proponents. In addition, the province is seriously considering the construction of the proposed Site C hydro facility on the Peace River, which will provide an additional 900 MW of capacity to the province and a reservoir with a surface area of 9,310 hectares.<sup>5</sup> If the project goes ahead, it could be completed as soon as 2020.

In theory, BC’s total generating capacity is sufficient to meet future provincial demand. However, because the vast majority of generating capacity is hydroelectric, capacity varies according to water availability, in-stream requirements and Treaty obligations related to flood control and power generation in the U.S.

Forecasts of future electricity demand have been made by BC Hydro (2008a) and by FortisBC (2009). Since these two utilities serve 100% of the provincial load, aggregating the two demand forecasts provides an indication of the province’s electricity demand over 2010 -2027.

<sup>5</sup> This raises the future possibility in the Peace River region of using the reservoir associated with Site C and the upstream Williston reservoir (behind Bennett Dam) in pumped-hydro storage system associated with potential wind-farm developments in the region.

Peak load is the demand-side equivalent of installed capacity. It is defined as the maximum instantaneous load or the maximum average load over a designated interval of time (usually no longer than one hour). In the BC Hydro (2008b) and FortisBC (2009) forecasts, the peak load is the maximum load in any one hour within a given year. Estimates of provincial peak load are provided in Figure 2.

Provincial peak demand is forecast to exceed the current capacity of 13,250 MW no earlier than in 2019. Until then electrical generation capacity is expected to remain above peak load requirements – the province currently has and is expected to continue to have excess generating capacity for at least the next nine years. Only if no additional capacity is added to the system (which is unlikely given BC’s Clean Energy Act) will demand exceed the potential to generate power. Of course, this conclusion depends crucially on the availability of sufficient water to facilitate operation at full generating capacity at the same time that a peak load is encountered.

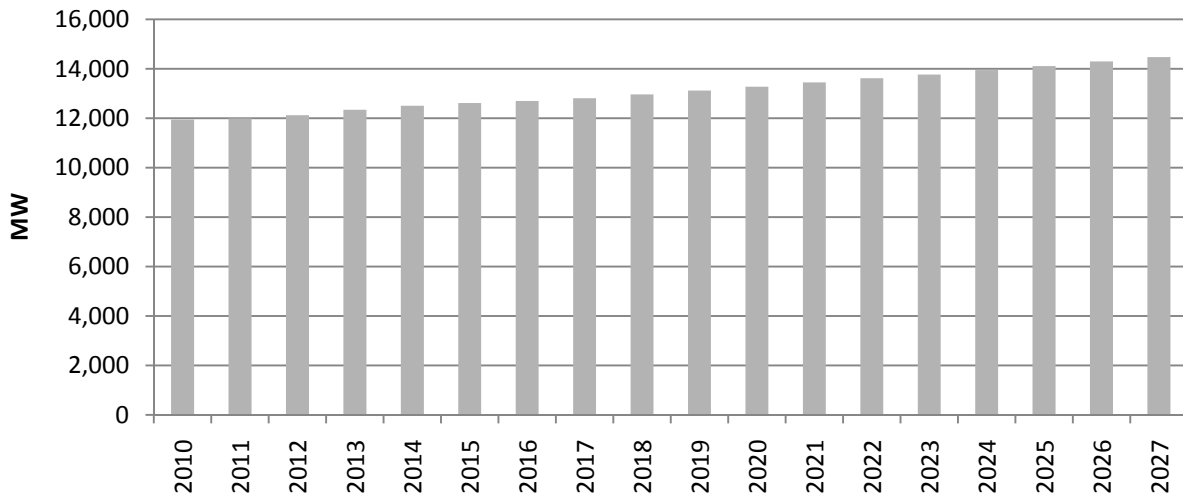


Figure 2: Total forecasted provincial peak load (MW), 2010 to 2027

The excess capacity argument is corroborated by data on BC Hydro’s System Capacity Supply (BC Hydro 2008a, Table 6-12). BC Hydro assumes there will be a reduction in load as a result of its demand-side management programs. Then, under normal load conditions and taking into account supply reserves, BC Hydro does not anticipate a shortage in capacity until F2028. In its LTAP, BC Hydro (2008a) subtracts 14% minus 400 MW of its available generating

capacity to set aside for reserves. These reserves are maintained to ensure that the system is able to meet domestic demand in all but the most extreme cases; typically a loss of load event occurs once in 10 years. By dedicating 14% of supply to reserves, BC Hydro calculates that it can ensure appropriate system dependability; it further assumes that 400 MW of the reserves can be procured in the market.

The LTAP states that total BC Hydro capacity is comprised of 9,700 MW of heritage hydroelectric generation, although available hydro capacity appears to be closer to 9,450 MW. This discrepancy requires further investigation. The second line item provides generating capacity figures for Heritage Thermal assets and Market Purchases. The Long Term Acquisition Plan (BC Hydro 2008a) was filed prior to the government's announcement to reduce the availability of the Burrard thermal gas plant, and so the forgoing figures include the capacity of that generating plant. The total capacity associated with thermal and market purchases was 950 MW, of which Burrard plant capacity accounts for 900 MW – intended market purchases are quite small. Interestingly, the System Capacity Supply includes 656 MW of Electricity Purchase Agreements, excluding the Alcan LTEPA. However, "as of April 1, 2010, BC Hydro has 63 Electricity Purchase Agreements (EPAs) with IPPs whose projects are currently delivering power to BC Hydro. These projects represent 10,343 GWh of annual supply and 2,629 MW of capacity" (BC Hydro 2010a, p.1). Removing Alcan's capacity from BC Hydro's list of EPAs reduces total available IPP capacity to 1,733 MW, a figure substantially greater than the 656 MW enumerated in the System Capacity Supply table (BC Hydro 2008a, Table 6-14). Capacity from Site C and the Mica upgrades appear as line items under proposed future supply, but there is zero capacity associated with these facilities through F2028. There appears to be a discrepancy between the amount of capacity available and the amount enumerated by BC Hydro (2008a), something which clearly needs further investigation. The Canadian Entitlement from the Columbia River Treaty is treated as "additional supply potential" but with zero associated MW of capacity after fiscal 2010.

BC Hydro (2008a, Table 6-15) also details its electricity flows over a fiscal year. As with System Capacity Supply, the supply of electricity appears to have the same types of distortion: underestimating the electricity from heritage hydro assets, existing EPAs and a failure to



include the potential future electricity to be generated from Site C or the Mica upgrades.

### **Available Electricity**

Since capacity exceeds load, theoretically and under ideal conditions British Columbia could meet all its electricity needs from domestic supply. However, capacity and demand (load) do not tell the whole story. A turbine's capacity is amount of power that can be generated or produced under normal conditions. Unlike thermal generating facilities where the fuel source is constant, a hydroelectric facility's output depends on water flows (as noted earlier). Hydro electricity is generated when flowing/falling water flows propels the turbine blades. The amount of power that can be generated from a large-scale hydroelectric unit – consisting of a dam, reservoir and generator(s) – depends on the quantity of water stored in the reservoir (elevation), water inflows from rainfall or snowpack runoff, and head height. Head height is the vertical height of the water in a reservoir above the turbine. In periods of drought, or at times when storage conditions are unfavourable, water volume may be lower than that required to operate the turbines at their capacity. Conversely, during periods of sufficient precipitation, water volumes must be managed for flood control and power generation while satisfying in-stream uses.

The fuel that drives large-scale hydropower generation is variable, but predictable and controllable to some extent because of reservoirs. The disparity between installed capacity and the actual ability to generate electricity is an issue for variable energy sources, principally run-of-river hydro, tidal power, solar photovoltaic (PV) and wind. It may even be a problem for biomass sources of energy, as the ability to generate power at full capacity depends on the availability of sufficiently low priced wood fiber and whether biomass is backstopped by coal or some other fuel source if wood biomass is too expensive.<sup>6</sup>

We define the *capacity factor* of a generating facility as the ratio of the actual power produced by a generator during the year to the generator's rated capacity multiplied by the

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<sup>6</sup> Wood fiber prices depend largely on lumber production, with more fiber available as lumber production increases, and competition for fiber by other users (pulp mills, OSB manufacturers, pellet producers, etc.). If fiber prices are too high, biomass generating facilities will close even with lucrative feed-in subsidies. This issue is discussed in detail by Stennes et al. (2010) and Niquidet et al. (2010). The most likely and sensible backup fuel would be coal, despite its high CO<sub>2</sub> emissions.

number of hours in one year (8760). For most base-load, thermal power plants (including nuclear), the capacity factor is 85 percent or more. For wind farms, the capacity factor can reach 40 percent at almost ideal sites, but average around 18 to 20 percent in most places (Pitt et al. 2005; van Kooten and Timilsina 2009; van Kooten 2010). Less is known about tidal systems, but capacity factors are comparable to those of wind turbines; for solar plants, capacity factors are also low due to clouds and nighttime, which is particularly acute in northern climates because power is most needed in the winter when the sun's duration and intensity are less. Capacity factors for run-of-river facilities also vary considerably from one season to the next, unlike large-scale hydro.

Under the Clean Energy Act, installed generating capacity will consist to a much greater extent of assets that rely on variable energy sources and are characterized by low (and often unknown) capacity factors. (In BC, run-of-river, wind and biomass appear to be the most popular forms of IPP energy.) Even so, it remains likely that power output will exceed domestic requirements. To the extent that external conditions (climate, environmental or economic) affect the decision to generate electricity, British Columbia can export or import energy as desired.

Information on power flows is collected by Statistics Canada (CANSIM), the National Energy Board (NEB 2010a, 2010b) and BC Stats (2010). The CANSIM data are collected via a monthly survey from provincial electricity generators. Survey respondents must provide information on the quantity of electricity generated, the primary fuel source used in its generation, and gross receipts and deliveries of electricity to other provinces. These are aggregated across respondents and available in CANSIM tables 1270001 and 1270003. The CANSIM, NEB and BC Stats data are identical, but breakdown the information differently. For example, CANSIM provides monthly data and has information on the types of delivery (firm and non-firm) as well as the source or delivery point (U.S., other provinces). From the NEB data, it is possible to determine the amount of power imported and exported for non-revenue purposes (i.e., 'Treaty power' and ancillary services/losses, etc.). BC Stats data are a summary of CANSIM figures.

In Figure 3, we track BC electricity exports, imports and net exports (exports minus

imports) between 1978 and 2008 using monthly CANSIM data. The data are aggregated over the province’s fiscal year, April 1 to March 31, to provide consistency with BC Hydro documents. The grey bars indicate net exports. Prior to 1993, BC was exclusively a net exporter. Beginning in 1993, BC varied its position from being a net exporter to net importer and back again on various occasions. In essence, British Columbia was exclusively a net exporter of electricity prior to 1993 – the amount of energy leaving the province consistently exceeded the amount entering. Between 1993 and 2008, BC was both a net importer and a net exporter of electricity. Over the past eight years (2000 to 2008), BC was a net importer in four years (2001, 2004, 2005 and 2008) and a net exporter in four years (2000, 2002, 2003 and 2007).

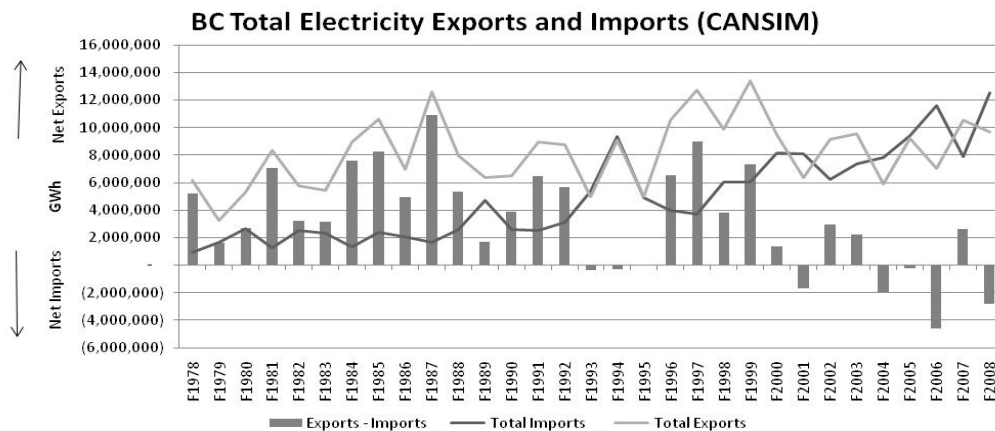


Figure 3: Net exports, total exports and total imports, 1978-2008

While the net export data from BC Stats (2010), CANSIM and the National Energy Board (2010b) are equivalent, none of the data sources agree with the dates and volumes of net exports from BC Hydro’s (2006) Integrated Energy Plan (IEP). The IEP states that BC Hydro was a net importer in five of the eight years – F2001, F2002, F2003, F2004 and F2005. The discrepancy around the net export question may be because BC Hydro generates a large portion, but not all, of the province’s electricity. It could also be related to the accounting measures used for BC Hydro sales to Powerex. As the electricity marketing subsidiary of BC Hydro, Powerex is responsible for marketing BC Hydro’s surplus electricity, including the Canadian Entitlement energy derived from the Canada-U.S. Columbia River Treaty. Clearly, it is important to distinguish between the net position of BC Hydro, its subsidiaries and the province

as a whole.

The CANSIM data are the aggregation of provincial survey results. Raw data on hourly power flows, both inter-provincial and international, are provided by British Columbia Transmission Corporation (BCTC) and are shown in Figure 4. The maximum available transfer capacity (ATC), or transmission capacity, for BC to the U.S. is 3,150 MW from north to south and 2,000 MW from south to north. With respect to the transmission capacity between Alberta and BC, the east to west capacity is 1,000 MW while the west to east ATC is 1,200 MW; however, operating limitations within Alberta often restrict the east-to-west capacity to 760 MW and the west-to-east capacity to 600MW. (The reasons for this are discussed in more detail below.) The ATC limits represent the maximum power that can flow along the transmission interties.

In Figure 4, the lighter line shows aggregated monthly flows between Alberta and BC, while the darker line provides the aggregated monthly flows along the BC-U.S. intertie. The aggregation masks the true volatility of the power flows. Imports are indicated by negative values and exports with positive ones. The raw data are from the BC Transmission Corporation (BCTC). Trends in the intertie data appear to be consistent with information from Statistics Canada and the NEB. BC was net exporter to Alberta and a net importer from the U.S. in 2008 and 2009, but a net exporter to both jurisdictions in 2007. The explanation for this import and export pattern is likely the result of variation in electricity prices in the adjacent markets and the revenue maximizing behavior on the part of British Columbia, as discussed in the next section. However, it is important to note that discrepancies of the sort discussed above may be a function of how BC Hydro and Powerex account for internal transfers and forward trades.

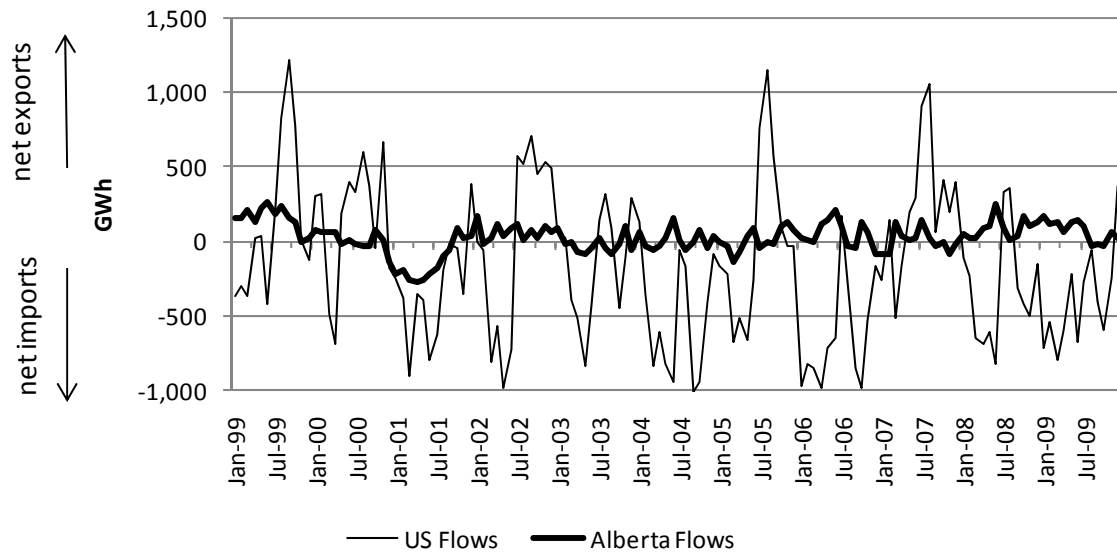


Figure 4: BC imports and exports of electricity along transmission interties with Alberta and the U.S. Pacific Northwest, January 1999 through July 2009

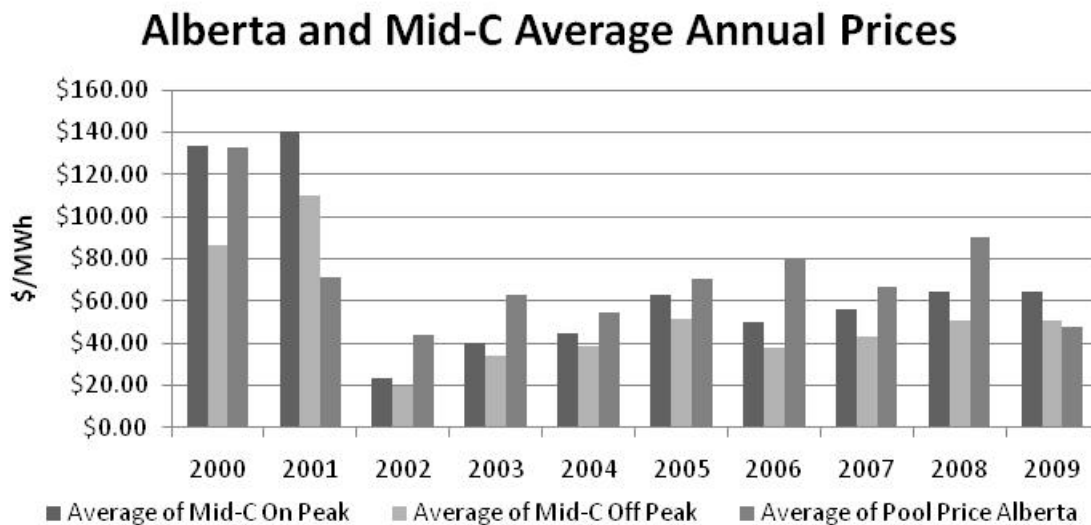
### Net Revenues Associated with Exports and Imports

Alberta is likely the electricity industry’s bellwether; the absence of regulation allows the market to act unencumbered. While operating with fully deregulated wholesale (and retail) energy markets, Alberta has already integrated over 600 MW of wind energy. The effect of this high wind penetration has been to increase the volatility of wholesale market prices. As the market price in Alberta rises, there is greater value to generating electricity (i.e., installing added capacity), including, importantly, renewable capacity.

Given the desire across North America to reduce CO<sub>2</sub> emissions associated with fossil fuel generation of power, particularly generation from coal, there may be increased opportunities for lucrative exports of clean energy to the U.S. U.S. renewable energy policies have left many jurisdictions supply constrained, resulting in higher prices. The restrictive conditions on the types of energy these states are permitted to import may benefit British Columbia because of its predominantly hydroelectric generation portfolio. As a result of its excess capacity, BC continues to be in a position to take advantage of higher prices in adjacent markets. Fundamentally, BC must decide at which price point it is economically beneficial to produce power for export; it must also determine at what price point it reduces domestic

production and meets domestic load by purchasing power from another jurisdiction. As prices rise in adjacent markets, BC will need to increase its capacity to leverage its naturally long position.

British Columbia exports and imports electricity from the United States and Alberta, and receives or pays the prevailing market price. In general, Alberta prices are determined by the Alberta Electric System Operator (AESO) on an hourly basis as a result of supply and demand. In the U.S., the price of electricity is determined at the Mid-Columbia (Mid-C) trading hub. BC Hydro sells 'excess' power to Powerex under the Transfer Price Agreement, which guarantees BC Hydro the Mid-C price. The Mid-C price is an index based on bilateral trades. Electricity markets in California as well as Palo Verde, Meade and the Four Corners affect the market price at Mid-C because electricity flows to the highest priced region. In the absence of transmission constraints, electricity prices would be equalized throughout the Western Electricity Coordinating Council (WECC). However, transmission constraints are prevalent throughout the Western provinces and states. Differences in the average electricity prices between Alberta and Mid-C provide evidence of this discontinuity in electricity flows, as indicated in Figure 5.



*Figure 5: Average electricity prices in Alberta and at Mid-Columbia, 2000-2009*

Differences in prices are a key factor explaining BC's import and export pattern. For

example, in 2008 Alberta's prices were high (Figure 5) and BC's net export position with that province was positive (BC was a net exporter of power); but BC was a net importer of energy from the U.S in the same year. There are times when it is prudent for BC to purchase electricity from its neighbours in Alberta and the U.S. Pacific Northwest because the price is low; other times, it will be lucrative to export energy to those areas. The price point that triggers imports and exports depends on the relative internal cost of producing electricity. According to the BC Hydro (2006), from 2001 to 2005 BC Hydro was a net importer of electricity, because "market purchases were economic to serve domestic requirements when compared to greater use of Burrard or greater drawdown of major reservoir" (BC Hydro 2006, p.3-7). An increase in imports is not indicative of an inability to meet load with domestic assets, but, rather, should be interpreted as prudent use of assets from a financial perspective – import prices were low relative to the cost of domestic generation.

In Figure 6, we plot Alberta electricity prices and power flows along the Alberta-BC transmission intertie. There is clear evidence of a strong correlation between the two series: as the price of electricity in Alberta rises, BC sends more energy along the intertie. This strongly suggests that BC acts as a revenue maximizing entity. Interestingly, the same pattern does not emerge when one compares Mid-C prices and flows along the BC-U.S. intertie. One reason for this may be that BC-generated electricity is primarily designed to meet demand in California, in which case the California/Oregon Border (COB) price is relevant. That is, the price dynamics at Mid-C may not capture the true value of BC power exports to the U.S.

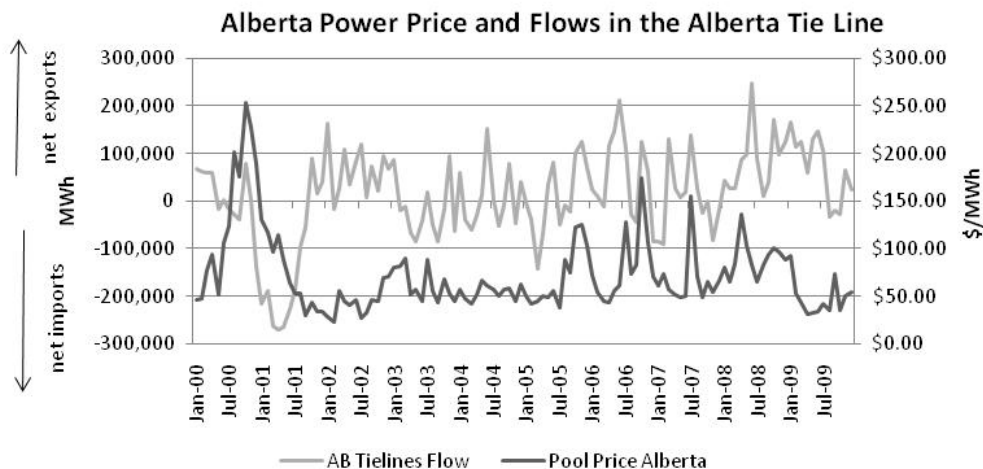


Figure 6: Hourly pool prices for Alberta electricity (dark line) and the power flows (grey line) along the Alberta-BC Intertie

In Figure 7, we plot British Columbia’s net exports of electricity and net revenues using CANSIM data from the NEB (2010b). BC has been both a net importer and exporter of power. The graph indicates that, in periods when net imports were large, net payments were often quite small, indicating that there was an economic rationale for imports. In December 2000, BC was a net importer a small amount of energy (< 1 GWh), but it received over \$288 million in net revenues that month. Export volumes in December 2000 were nearly identical to import volumes (577.09 GWh vs. 578.04 GWh), but export revenues were four times larger than import revenues (\$387 vs. \$99 million). A similar situation where net revenues were positive while net exports of electricity were negative occurred in 21 months over the past nine years of NEB data. The differences between power flows along interties and electricity revenues may be explained by the province’s net export profile.

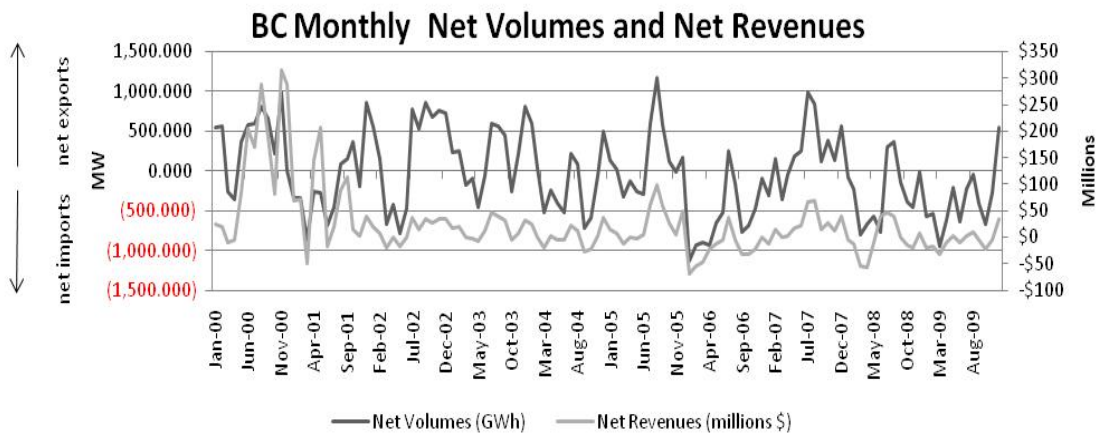


Figure 7: Monthly net electricity exports (dark line) and net revenues from sales/purchases of electricity (grey line), British Columbia, 2000-2009

### Net Export Profile

Under the presumption that BC is using its storage capacity to maximize revenues, it is expected that BC imports would occur during low price periods – during low demand hours – and that BC would export during peak daytime hours when prices are high. In Figure 8, we



provide an average of the hourly flows along the two transmission interties for selected years (2000, 2001, 2008 and 2009). Negative values indicate a net import position, while positive values represent exports. Due to the aggregation of both positive and negative values, some information has undoubtedly been lost. Nonetheless, the general trends are indicative of provincial import and export behaviour.

Net exports to Alberta increased from 7 am (HE 7) to 10 pm (HE 22) which corresponds to Alberta’s peak demand hours. During Alberta’s off-peak hours, BC is importing. Overall, BC tends to be a net exporter to Alberta (Figures 5 and 6), but it is generally a net importer relative to the United States (Figure 5). Yet, BC appears to be practicing the same revenue maximizing strategy with respect to the U.S. market as imports are relatively larger during off-peak hours and during peak times, when they fall.

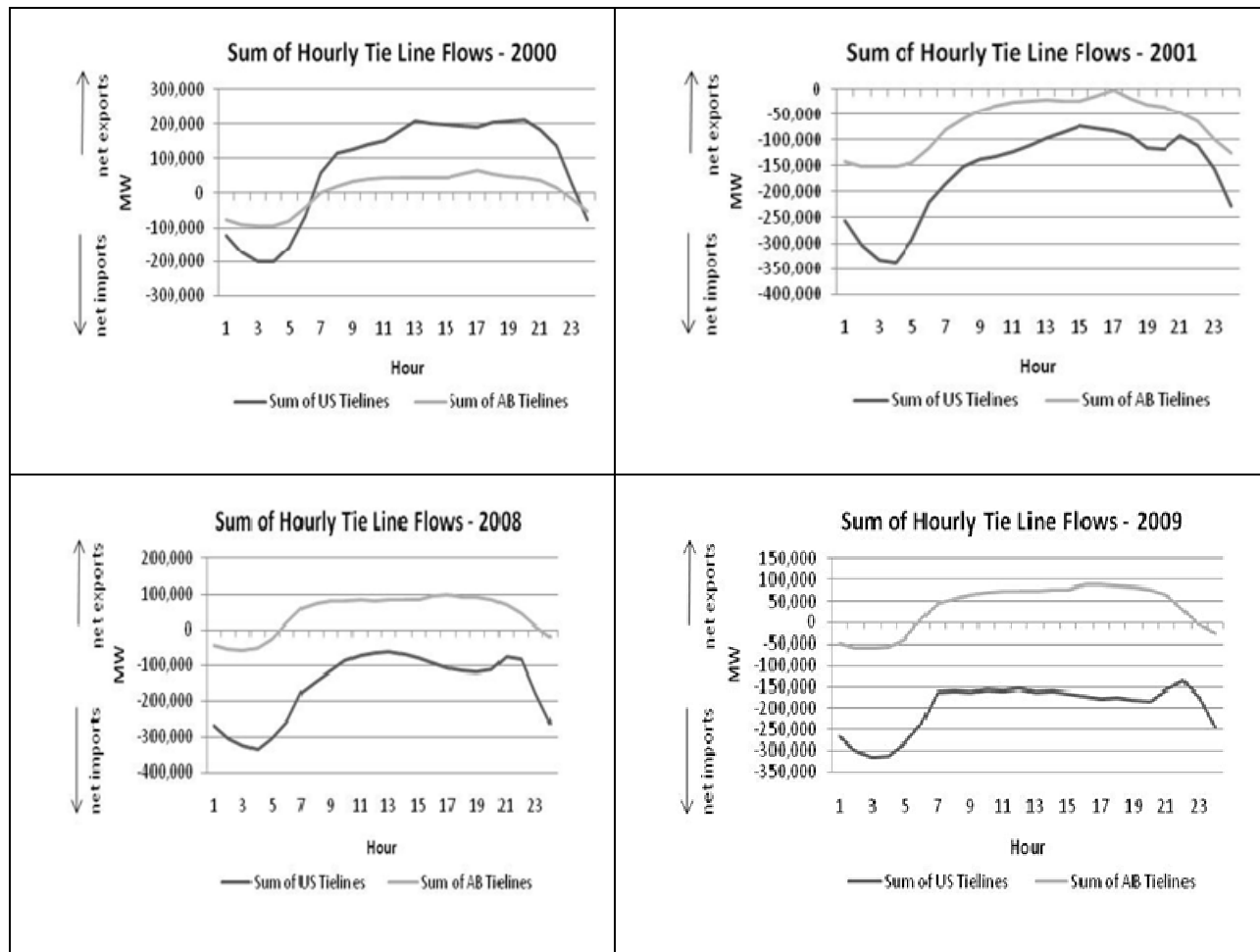


Figure 8: Annual average hourly flows along the BC-Alberta and BC-U.S. Interties, selected years

British Columbia's export pattern varies depending on the market and capacity of the transmission interties. The east-west relationship is diurnal. It is expensive for Alberta's coal-fired power plants to ramp down at night only to ramp back up a few hours later. Although some ramping does take place, the assets in question prefer to sell power to BC, even at low prices, to avoid the costs of tracking nighttime load downwards. BC takes advantage of low Alberta prices at nighttime by importing excess power, saving water for future electricity generation. In the daytime, when prices are higher in Alberta, BC exports power thereby increasing its revenues. This pattern has existed since 2000. Even if the amount exported is less than what is imported, the higher price of exports relative to imports results in an overall advantage to British Columbia. For this reason, Alberta has been reluctant to increase the capacity of its infrastructure to enable the trade to take place at the rated capacities of the intertie. We discuss this further in the next section.

With respect to the U.S. markets, it is important to recognize that BC exports and imports of electricity are small relative to the overall size of the market. The export-import relation is less diurnal (as was the case with Alberta) than it is seasonal. During winter, BC requires more electricity for heating (because it is colder) and lighting (because it is dark longer). Further south, principally in California, Arizona and Nevada, the demand for electricity is lower than during summer because heating needs are not onerous and the summer-winter contrast between daylight and night time is less pronounced. Hence, there is less demand for electricity in winter than summer while demand in BC (and much of the northern states in the WECC system) is higher. During summer (July, August, September), BC requires less electricity, but demand is high in the United States, mainly for air conditioning. Therefore, we would expect BC to export power (or import less) during summer. This pattern is confirmed in Figure 9, where we observe that BC is generally a net importer of electricity from the United States in the winter and spring, and a net exporter in the summer and sometimes fall. Notice that BC does import electricity from the U.S. some summers (2001, 2006, 2009), but the amount is much less than what is imported at other times of the year (except if imports continue into the fall). Compared to years when electricity is exported in summer, imports are much smaller.

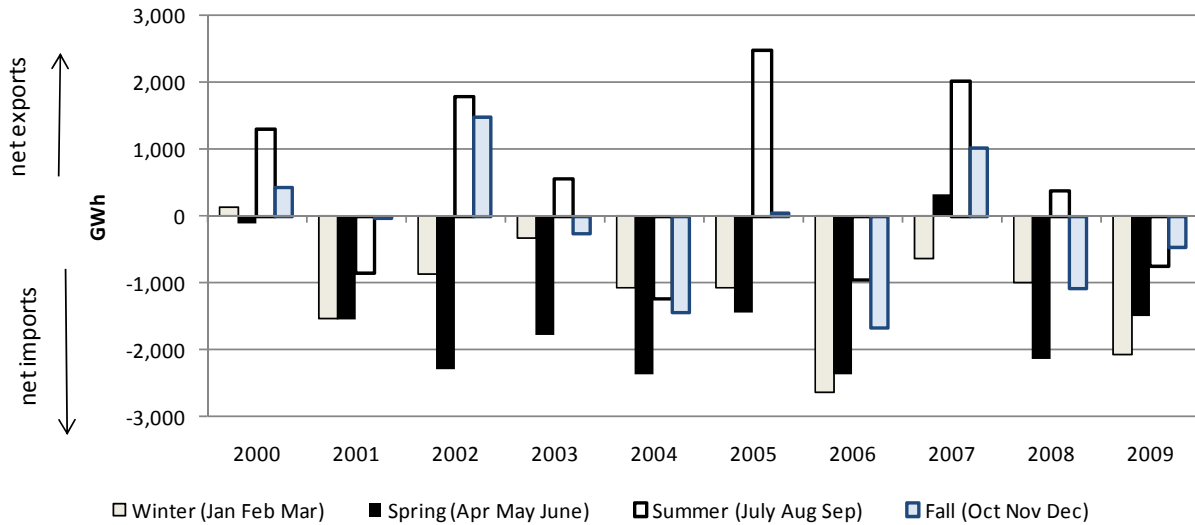


Figure 7: Historic seasonal volumes on the U.S. transmission intertie

Not included in the discussion of the exchange between the U.S. and British Columbia is the issue of Columbia Treaty power that is generated in the United States but attributed to BC.

## Discussion

It would appear as though the province of British Columbia currently has sufficient generating capacity to meet its demand for electricity, including peak load needs. This excess of capacity over load is expected to continue for the next several years at least, even without the addition of new generating capacity. The construction and operation of the Clean Power Call selected proposals, upgrades to existing facilities and the Site C project will further increase the gap between capacity and forecasted peak load. As that gap grows BC will be in the position to export increasingly larger volumes of energy to adjacent markets.

There is also no reason to believe that domestic load will and should be met entirely by domestic generation. Indeed, it may be financially beneficial for British Columbia to import electricity when prices in other markets are low relative to the internal opportunity cost of generating electricity. Likewise, when market prices in adjacent markets are high, it makes economic sense to export electricity. These exports and imports are over and above transfers required to enable other system operators to stabilize the overall WECC grid.

There are several issues that need to be considered. First, the policymaker needs to

know BC's internal cost of generation and the shadow prices of storing water behind dams for future release and power generation if the financial benefits of exchange are to be maximized. The non-market benefits are a separate issue, but mainly relate in-stream requirements and to CO<sub>2</sub> emissions. We consider the former but not the latter.

It is not clear whether British Columbia is importing coal-generated power from Alberta during off-peak hours, or that it will continue to do so in the future. The story told in the previous section about the expense of having coal-fired generators ramping down to track nighttime load is likely correct. Currently, it would appear that BC imports electricity from Alberta that is generated using coal, implying has high CO<sub>2</sub> emissions. However, there may be little environmental benefit should BC decide to stop power imports for that reason,<sup>7</sup> while there might well be a large loss in revenues. Suppose BC stopped purchasing nighttime power from Alberta. This would require substituting Alberta electricity with that generated by existing hydro assets, or some other source (perhaps biomass). This does not mean that Alberta reduces its emissions of CO<sub>2</sub> on a one-for-one basis. Alberta's coal generators are likely to continue operating, burning fossil fuel, but not dispatching electricity to the grid. In that case, BC's action has done nothing to reduce the two province's overall CO<sub>2</sub> emissions and may even increase overall emissions, which would clearly be the case if the substitute power were produced from biomass (see Searchinger et al. 2009). Thus, this strategy needs to be carefully thought out if one objective is to address climate change concerns. There is likely little to be gained and a lot to lose by putting a stop to a profitable exchange of electricity.

But there is another problem that BC policymakers might need to address. As noted earlier, Alberta's decision makers appear reluctant to increase the capacity of the transmission lines between Alberta and BC, focusing instead on enhancing the transmission capacity between southern and northern regions of the province and construction of a transmission intertie into the U.S. grid through Montana. Alberta has invested in more than 600 MW of wind capacity and plans to increase this further. Although BC is the logical place to store wind-generated power, this does not seem to register on the Alberta side. The increase in north-

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<sup>7</sup> The Clean Energy Act implies that BC clean energy will displace "electricity generated by hydrocarbon-based fuel sources such as coal" (p. 1).

south transmission capacity is one way in which Alberta is seeking to benefit from greater wind power. But this does not get around the problem of intermittency that storage can address (see Scolah et al. 2010; van Kooten 2010; Pitt et al. 2005). And unless the problem of intermittency is addressed, Alberta cannot reduce its reliance on coal-fired power.

Alberta can avoid the intermittency associated with wind and yet reduce coal-fired, base-load capacity by combining large-scale wind farms with fast-responding gas plants that employ the latest technology to reduce the costs associated with frequent stops and starts. (Such a facility would also supply peak load.) A combined wind-gas plant might produce electricity at higher costs and with greater emissions of CO<sub>2</sub> than a wind-hydro alternative, but it will certainly produce less CO<sub>2</sub> than a coal plant providing the same power output. However, research is required to determine the associated costs and benefits, including environmental costs and benefits, of such base-load facilities.

It is not clear why Alberta appears to be choosing the wind-gas option over the wind-hydro alternative, but it might see that it is at a disadvantage in its dealings with BC. Because power output from wind farms tends to be greater at night than during the day, BC would continue to be able to exploit the diurnal relation that it now enjoys, but to an even greater extent if a higher-capacity transmission link were to be built. Unless British Columbia is willing to share some of this windfall rent, Alberta's actions appear justified. Alberta will continue to replace coal-fired capacity with wind-gas, while enhancing intra-province transmission to take advantage of the best wind sites. Unless it is willing to bargain with Alberta, BC could lose out on an opportunity to generate large windfall revenues while, at the same time, reduce overall CO<sub>2</sub> emissions. After all, the BC government (2010) intends "to work in partnership with renewable power producers to actively seek opportunities to sell clean, reliable electricity to neighbours in Canada and the U.S."

With regard to the transfer of power between BC and the U.S. Pacific Northwest, clean energy from BC would likely displace natural gas generators not coal units. Although the portfolio used to generate energy moving to the Mid-C hub is larger and more complex, the fuel at the margin is typically natural gas. It is the marginal unit that would be affected by BC clean energy exports.

It is not clear, therefore, that so-called clean energy exports from BC will displace 'dirty' energy in an adjacent market, as required under the Clean Energy Act. Indeed, it might even be the case that exports of BC clean energy displace another form of renewable energy, or that they simply result in wasted energy. Clearly, before BC embarks on a trajectory that makes it a major exporter of clean power, some serious research needs to be undertaken to determine the overall financial *and* environmental costs.

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