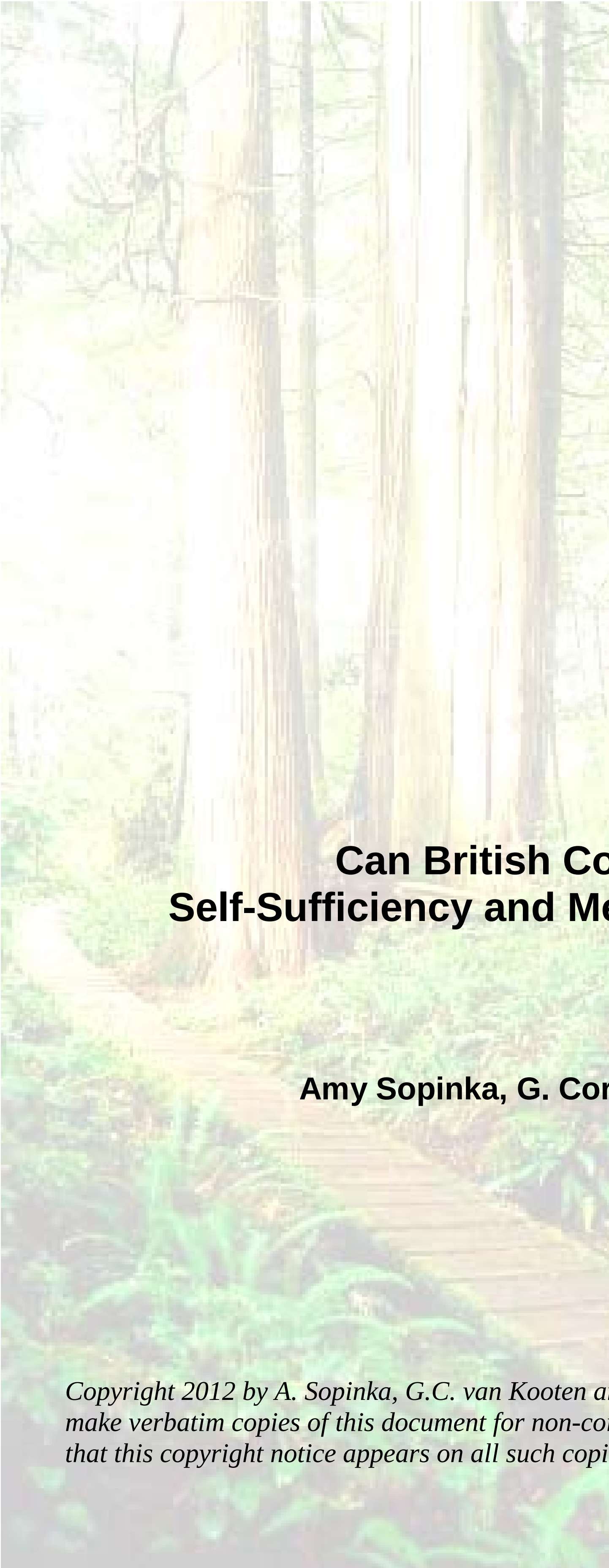

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Can British Columbia Achieve Electricity Self-Sufficiency and Meet its Renewable Portfolio Standard?

Amy Sopinka, G. Cornelis van Kooten and Linda Wong

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Can British Columbia Achieve Electricity Self-Sufficiency and Meet its Renewable Portfolio Standard?

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Abstract

British Columbia's energy policy is at a crossroads; the province has set a goal of electricity self-sufficiency, a 93% renewable portfolio standard and provincial natural gas strategy that could increase electricity consumption by 2,500-3,800 MW. To ascertain the reality of BC's supply position, we model the physical characteristics of BC's hydroelectric generating system introducing variable head heights for the two dominant power stations. Using historical inflow and reservoir level data, we apply our linear programming model to investigate whether BC is capable of meeting is self-sufficiency goals under various supply and demand scenarios.

Key Words*:* hydroelectric, power generation, variable head, drought

JEL Categories: Q25, Q42, Q47, Q58

1. Introduction

The Province of British Columbia is committed to becoming energy self-sufficient by 2016, and this includes the ability to generate an additional 3000 MWh of insurance energy. There is substantial controversy surrounding this goal as it is remarkably difficult to decipher whether BC has been a net importer or exporter of electricity in the past, because of the distorting effects of its revenue-driven energy transactions. At times, BC imports less expensive energy from adjacent regions to save water for future energy production; it may export energy to high priced regions for revenue and use the accrued financial gains to purchase lower-priced energy at other times. Such decisions are meant to maximize net revenue, but there are also times when BC imports electricity simply to meet internal load when there is a shortfall in domestic supply. Because hydroelectricity accounts for more than 90% of generating capacity, shortfalls occur primarily when low reservoir levels reduce available generating capacity.

Whether the province can be self-sufficient given the current state of British Columbia's electrical system is the question addressed in this paper. We develop a mathematical programming model of the BC electrical system that allows the province to trade electricity with Alberta and the United States. Hydroelectric power production on the two largest rivers (Columbia and Peace) is modeled independently, while remaining hydroelectric production is assumed to be constant and is treated as must run. There is also an option to produce thermal power despite provincial policy that aims to reduce production of electricity using fossil fuels, and nuclear power is ruled out altogether.

Our constrained optimization problem maximizes domestic revenue subject to meeting technical constraints, including serving daily domestic load over a one year period. We find that, with no trade and no thermal generation, it is impossible to meet domestic load given the remaining resource configuration. When thermal generation is added, normal system demand can be met over a one year period even in the absence of trade, but reservoir live storage volumes will need to be drawn down to 70 percent of their original starting levels. Once imports from Alberta and/or the U.S. are permitted, imported energy displaces thermally-generated electricity, and, as the level of imports increases, higher end-of-year reservoir storage requirements can be met. Clearly, British Columbia is currently not self-sufficient in electricity production.

While load will likely continue to increase with population growth, the more pressing question relates to how the provincial government is going to rationalize the self-sufficiency goal with its commitment to produce and export liquefied natural gas (LNG). The *BC Jobs Plan* (British Columbia, 2012) states that BC will have at least one natural gas pipeline and LNG production facility and terminal in operation by 2015 and three by 2020. When shale gas exploitation is taken into account, the province will require between 2600 MW and 3750 MW of new generation capacity. The BC oil and gas industry, the largest revenue sector in BC's economy, will continue to drive both economic growth and electricity demand. In December 2010, BC Hydro forecast that the electrical load from the oil and gas industry would grow by 630 percent over the next five years.

To reduce the gap between actual and required generating capacity, the province could allow for self-generation via natural gas fired units in the province's northeast – the gas is available at low cost and, since generation is on-site, transmission issues are all but eliminated.[1] However, the 2010 *Clean Energy Act* requires the province to achieve an 18% reduction in provincial CO_2 emissions from 2007 levels, meet 66% of new energy demand through

[1] Electricity generated in the northeast could not only service the oil and gas industry in this region but, given extant transmission lines from the northeast to the province's major load center in the southwest and to the U.S., gas-fired power could potentially be transferred farther afield.

conservation initiatives, and use clean or renewable resources to generate electricity. Since natural gas-fired generation in BC is considered neither clean nor renewable, the development of gas-fired generation would count against the 93% renewable standard imposed by the legislation. Clearly, British Columbia is at a policy crossroads – it can try to achieve economic growth through resource development or it can aim for energy self-sufficiency, but it likely cannot achieve both.

2. Existing BC Electricity Infrastructure

BC Hydro is the single largest entity in BC's electricity sector and the third largest utility in Canada. The government-owned corporation serves 94% of the province's population. Its assets include large-scale hydro facilities with storage, run-of-river generating assets and two thermal generating units. BC Hydro divides its generating system into four regions: Peace, Columbia, Vancouver Island and the lower mainland.

The Peace region includes two major generating facilities on the Peace River – the GM Shrum and Peace Canyon dams. Shrum is comprised of ten generating units that are fed by water flowing from the province's largest storage system, the Williston Reservoir (39,462 million m^3). The Peace River flows through Shrum into Dinosaur reservoir and then through the Peace Canyon dam and generating station. The same amount of water flowing through Shrum also flows through the Peace Canyon turbines making the Peace Canyon station a run-of-river facility. Summary information regarding the various dams is provided in Table 1.

The Columbia basin includes the Columbia, Kootenay, Pend D'Oreille, Bull, Elk and Spillamacheen Rivers. The Columbia River originates in British Columbia and flows through Montana, Idaho, Washington and Oregon before spilling into the Pacific Ocean. The Columbia River Treaty is an international agreement negotiated between Canada and the U.S. that oversees the development and operation of dams in the upper Columbia River basin.

Table 1: Electricity Requirements and Sources of Supply, 2008

Requirements	Capacity (MW)	GWh	%		
Domestic	12,280	53,300	55.3%		
Electricity Trade		37,450	38.8%		
Subtotal		90,750	94.1%		
Line Loss and System Use		5,676	5.9%		
Total		**96,426**	**100.0%**		
Sources of Supply	Capacity (MW)	GWh	%	Daily Average (GWh)	Capacity Factor (%)
Hydroelectric Generation					
G.M. Shrum	2,730	16,477	17.1%	45.019	68.7%
Revelstoke	1,980	9,496	9.8%	25.945	54.6%
Mica	1,805	8,562	8.9%	23.393	54.0%
Kootenay Canal	583	3,083	3.2%	8.423	60.2%
Peace Canyon	694	4,054	4.2%	11.077	66.5%
Seven Mile	805	2,880	3.0%	7.869	40.7%
Bridge River	478	2,793	2.9%	7.631	66.5%
Other	1,167	4,795	5.0%	13.101	46.8%
Subtotal	*10,242*	*52,140*			
Thermal Generation					
Burrard	950	260	0.3%		
Other	137	353	0.4%		
Purchases Under Long Term Commitments		11,878	12.3%		
Purchases Under Short Term Commitments		32,281	33.5%		
Exchange Net		-485	-0.5%		
Total		**96,427**	**100.0%**		

Source: BC Hydro (2008c)

Although the federal government negotiated the Treaty on behalf of Canada, the Canadian benefits and costs are solely attributable to the province of British Columbia. Under the Columbia River Treaty, BC was obligated to construct and operate three dams (Mica, Arrow and Duncan) for the purpose of flood control that benefited the U.S. In essence, BC agreed to operate storage in Canada to prevent floods in the U.S. and optimize power production from U.S.

dams on the Columbia River. Through BC Hydro, the province covered the cost of constructing and operating the Treaty dams, while receiving one-half of the resulting increase in power generated in the U.S., which was assigned to BC Hydro's marketing subsidiary, Powerex.

The Libby Coordination Agreement was negotiated in 2000 to resolve a dispute between BC Hydro and the Bonneville Power Authority (BPA)/U.S. Army Corps of Engineers. 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, one non-federal nuclear power plant and several other small 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 in its service territory, which includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming. The coordination agreement allows the BPA and the Corps to operate the Libby Dam in Montana for fisheries purposes without reducing the power benefits that British Columbia is entitled to under the Columbia River Treaty.

At the top of the Columbia River is the Kinbasket reservoir that stores 14,802 million m^3 of water behind the Mica dam and generating station. The Mica powerhouse has four turbines with a total 1,792 MW of capacity. BC Hydro is in the process of upgrading Mica's generating capacity by installing another two 500 MW turbines that will provide an additional 1,000 MW of capacity.

Downstream from Mica is the Revelstoke reservoir, generating station and dam. Revelstoke turbines are powered by water flowing from the Kinbasket reservoir as well as from local inflows. Essentially the Revelstoke power house operates as a massive run-of-river facility.

Downstream of Revelstoke is the Hugh Keenleyside Dam that forms the Arrow Lakes Reservoir. BC Hydro and Columbia Power Corporation have recently completed the installation of 185 MW of generating capacity just downstream of the Keenleyside dam.

The Seven Mile generating station is located on the Pend D'Oreille River and has an installed capacity of 594 MW. The Skagit Valley Treaty provided the province with the ability to alter the reservoir level at the Seven Mile dam, but it obligates BC Hydro to deliver the equivalent of 35.4 MW of capacity to the Seattle load center. BC Hydro is compensated by Seattle for this energy through a series of negotiated payments.

The Columbia basin contains five other smaller generating stations (Aberfeldie, Elko, Spillimacheen, Walter Hardman and Whatshan) operated by BC Hydro. These provide the province with a total of 79 MW of generating capacity.

The largest generating facility in the lower mainland area, and the third largest of BC Hydro's units, is the Bridge River complex. It includes the La Joie Dam and its 25 MW powerhouse, the 480 MW Bridge River generating units and the 24 MW Seton power station. There are an additional nine hydro generating facilities in the lower mainland area with a total 542 MW of sustained generating capacity. In addition, the lower mainland area has the province's largest thermal power plant – the 912.5 MW capacity Burrard natural gas plant; a second thermal power plant with a 46 MW capacity is located in Prince Rupert.

Vancouver Island is tied to the lower mainland's transmission infrastructure. The lower mainland provides nearly 80% of the Island's electricity needs through undersea interties. The remaining energy requirements are met by 458 MW of local hydroelectric generation, including three power generation stations on the Campbell River.

BC Hydro's franchise area is the entire province of British Columbia, but excludes the area serviced by FortisBC (formerly known as West Kootenay Power), 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. FortisBC operates four hydroelectric generating stations on the Kootenay River: Corra Linn, Upper Bonnington, Lower Bonnington and the South Slocan. The four projects provide the province with 235 MW of installed capacity. The Kootenay Canal generation station provides a further 570 MW of capacity, and the Brilliant generating station downstream of the Kootenay Canal project provides an additional 125 MW of capacity. The Kootenay Canal facility is operated by BC Hydro in conjunction with FortisBC to optimize the output from all the Kootenay River plants; the Brilliant facility is owned by the Columbia Power Corporation but operated by FortisBC.

In addition to publicly-owned generation facilities, several independent power projects (IPP) are operated by private firms with others being built. Teck is an international mining corporation operating in British Columbia; it owns a two-thirds interest in Waneta Dam and 15 km of transmission line connecting its BC operations to the U.S. Rio Tinto Alcan owns the Kemano hydroelectric facility and the accompanying transmission assets that enable it to connect to BC Hydro's grid. Nonetheless, BC Hydro manages the largest share of the provincial capacity, although IPP generation is growing in size and importance in the BC generating portfolio.

British Columbia is able to flow energy to 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 (see Figure 1). The operational transfer capacity (OTC) represents the maximum amount of electricity that can flow along the transmission interties. For BC, the OTC 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

OTC is 1,200 MW; however, in 2010, operating limitations within Alberta restricted the east-to-west capacity to about 390 MW and west-to-east capacity to just over 500 MW.

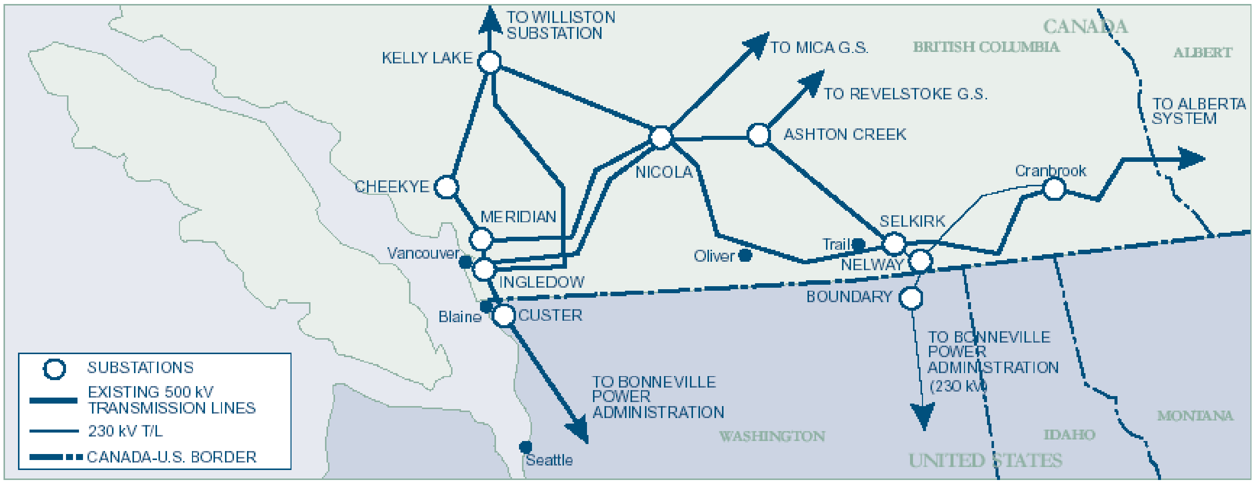

Figure 1: Existing Internal Transmission and Interties to Other Jurisdictions

3. Generating Capacity vs. Power Production

To determine whether BC is a net importer or exporter 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). Fossil fuel-fired generators are able to provide power consistently near their MCR because of a constant and unvarying fuel supply. The electricity that is generated from intermittent 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, adequate head height, which depends on reservoir levels (also known as elevations). Treaty and in-stream environmental considerations, such as flood control and fish habitat, affect the owner's ability independently to manage these elevations. Thus, the power output from hydroelectric generators may vary significantly from their rated capacity 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. 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 rating, 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).

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 included power generators (many of which were added later), 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 2012, excluding the Burrard thermal plant, we estimate that British Columbia has approximately 14,810 MW of generating capacity. The Burrard natural gas plant is a peaking plant that is used when (peak) demand and export commitments happen to exceed immediate generation. On October 28, 2009, the BC Ministry of Energy and Mines announced that it would be used to provide electricity to the grid only in emergency cases of generation and transmission outages, or to provide reactive power to maintain voltage requirements within system tolerance limits.

Total provincial generating capacity is essentially, therefore, comprised of 10,277 MW of BC Hydro capacity, 850 MW of FortisBC managed capacity, and 2,313 MW of existing independent power projects, plus 200 MW of capacity that Rio Tinto Alcan has allocated at its

Kemano facility to the province. In addition, British Columbia is allocated the Canadian Entitlement power from the Columbia River Treaty, which provides capacity equivalent to 1,170 MW of installed generation. The composition of currently available capacity is shown in Figure 2.

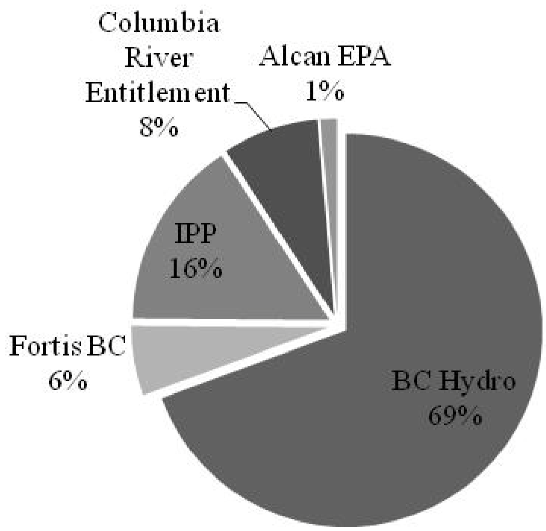

Figure 2: Ownership of BC's 13,250 MW of generating capacity

In the future, BC Hydro is planning to upgrade the Mica dam site with two turbines that will provide an additional 1,000 MW of capacity; while a 500 MW upgrade to the Revelstoke dam is currently under construction. 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 capacity will be constructed from the selected proponents. In addition, the province is moving ahead with development of the proposed Site C hydro facility on the Peace River, which will provide an additional 1,098 MW of capacity to the province and a reservoir with a surface area of 9,310 hectares. The expected completion date for the project is 2020.

Disregarding LNG and projected oil and gas development, BC's total generating capacity is greater than peak load as estimated by BC Hydro in its 2008 *Long Term Acquisition Plan* (LTAP) and by FortisBC in its 2009 *Resource Plan*. Since these utilities serve 100% of the provincial load, aggregating the two demand forecasts provides the total forecasted electricity demand between 2010 and 2027.

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 designed interval of time (usually no longer than one hour). In the BC Hydro and FortisBC forecasts, the peak load is the maximum load in any one hour within a given year. Without the development of LNG facilities and mining projects, provincial peak demand is forecast to exceed the province's existing generating capacity of 14,810 MW no earlier than in 2019.

This excess capacity argument is corroborated by data on BC Hydro's System Capacity Supply (BC Hydro, 2008a). 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 2028. In its LTAP, BC Hydro subtracts 14% from its available generating capacity and an additional 400 MW for reserve purposes. These reserves are maintained to ensure that the system is able to meet domestic demand in all but the most extreme circumstance; the industry standard is to maintain supply so that a loss of load event will occur only once in 10 years.

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 10,277 MW. This discrepancy requires further investigation but is beyond the scope of this paper. The second line item provides generating capacity figures for Heritage Thermal assets and Market Purchases. The *Long Term Acquisition Plan* was filed prior to the government's announcement reducing

Burrard's availability, and so the figures include the capacity of the Burrard thermal plant. The total capacity associated with thermal and market purchases was 950 MW, of which Burrard plant capacity accounts for 912.5 MW; thus intended market purchases were projected to be quite small. Interestingly, the System Capacity Supply includes 656 MW of electricity purchase agreements, excluding its contract with Alcan. 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), indicating a capacity factor of 0.449. 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).

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 2028. The Canadian Entitlement from the Columbia River Treaty is treated as "additional supply potential" but with zero associated MW of capacity after 2010. There appears to be a discrepancy between the amount of capacity available and the amount enumerated by BC Hydro (2008a).

BC Hydro (2008a) 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 purchase agreements (EPAs) and a failure to include the potential future electricity to be generated from the Columbia Entitlement, Site C or the Mica upgrades.

4. Model of BC Power Systems

The purpose of our model is to address the question of whether BC can attain energy self-sufficiency given its currently available resources. We model the BC electricity system by treating most hydroelectric facilities as must-run (with output determined by river flow) and concentrate on the operations of the two largest generating facilities and the downstream facilities affected by their outflows, namely, the operations of the Williston/Dinosaur reservoirs on the Peace River and the Kinbasket/Revelstoke reservoirs on the Columbia River.

Since the electricity sector in British Columbia is dominated by hydro power, we focus on the province's hydroelectric generating assets, although we allow for thermal units to be used as required and for imports and exports when it proves economically feasible.

4.1 Hydrometric, Hydroelectric Generating, System Load and Financial Data

Data for historical inflow, outflow and reservoir elevation are from the Environment Canada Data Explorer (ECDE) and the HYDAT Database, both distributed by the Water Survey of Canada. The average inflows are calculated as the average of the inflows prior to dam construction; average outflows and average reservoir elevations are the averages after dam construction. Information about hydroelectric generating capacity, constraints and technical specifications are primarily from Sawwash (2000) and BC Hydro (2008c).

Historical balancing authority load (demand) data are available from BC Hydro (BCTC 2010b). The data are provided as hourly load, including imports and exports, and have been aggregated to derive daily demand. This is shown in Figure 3.

Revenue and cost data are from BC Hydro's *2008 Annual Report*. A summary of the financial information used is provided in Table 2. (Average daily electricity generation for select power systems are reproduced in Table 1.) BC Hydro is permitted to earn an allowed return on equity, with tariff rates based on BC Hydro's cost and equity forecasts. Uncontrollable costs are related to unanticipated water inflows, energy prices (including thermal fuel costs), and trade revenues (BC Hydro 2008c). Trade revenues (costs) are generated through the sales (purchases) of electricity to (from) the U.S. or Alberta. These are calculated on the basis of the 2008 historical average import and export prices shown in Table 3.

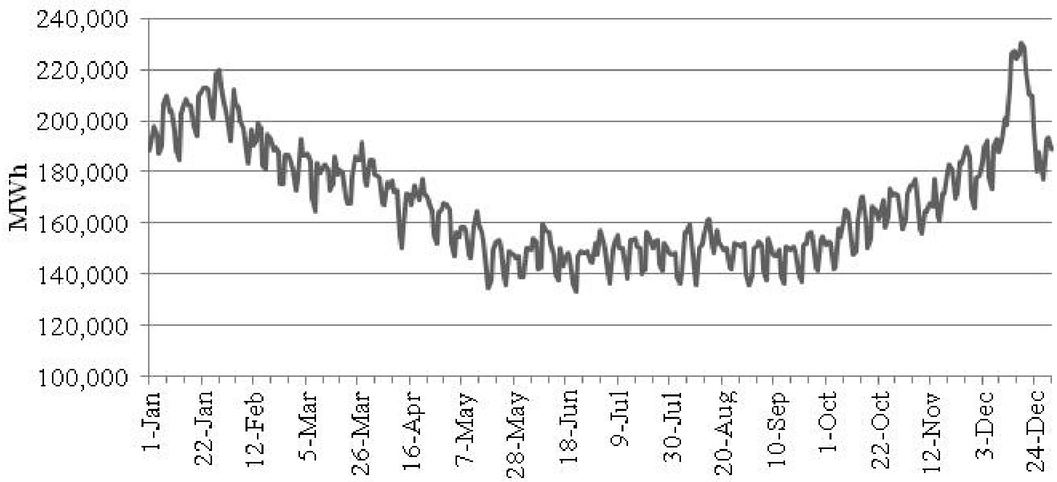

Figure 3: 2008 BC daily demand in MWh

Table 3: BC Import and Export Prices

	Import Price ($/MWh)	Export Price ($/MWh)
Alberta	$118.32	$45.42
U.S.	$76.46	$64.99

Source: National Energy Board (2008)

Table 2: BC Hydro Revenues and Costs, 2007-2008

Revenues		in millions 2008	in millions 2007	in GWh 2008	in GWh 2007	$/MWh 2008
	Domestic	2,944	2,786	53,300	52,911	55.23
	Trade	1,911	1,409	51,815	41,336	36.88
	Electricity	1,053	904	37,450	33,372	28.12
	Gas	858	502	14,365	7,964	59.73
Costs						
	Hydro generation	318	259	51,655	44,886	6.1
	Purchases from IPP and other long term contracts	477	363	7,765	6,041	61.39
	Gas for thermal generation	64	78	613	1,060	104.67
	Allocation from (to) trade energy	-126	67	-2412	656	56.04

Source: BC Hydro (2008c)

4.2 Constrained Optimization Model

The model described in this section focuses on power generation in BC, but is similar to the mathematical programming model outlined by van Kooten (2013) and Scorah et al. (2012). The model is specified as a constrained maximization problem where the objective is to determine the daily electricity generated by each asset that maximizes annual profit subject to minimum energy supply requirements and technical constraints on energy generation. The objective function is formalized as:

$$max_{Gen_{t,G}}\, \pi = \sum_{t=1}^{366} \begin{bmatrix} P_{BC} \cdot load_t - \sum_G C_G \cdot Gen_{t,G} \\ +P_{E,AB} \cdot Export_{AB,t} - P_{I,AB} \cdot Import_{AB,t} \\ +P_{E,US} \cdot Export_{US,t} - P_{I,US} \cdot Import_{US,t} \end{bmatrix} \tag{1}$$

where $Gen_{t,G}$ is the energy generated from power system G in period t; P_{BC} is the domestic price of electricity; $load_t$ is the daily load in MWh; C_G is the average generation cost of generating type G; $P_{E,AB}$ and $P_{E,US}$ are the average export prices per MWh for Alberta and BC, respectively; and $P_{I,AB}$ and $P_{I,US}$ are the average prices of imports from Alberta and U.S., respectively.

Total energy generation must exceed domestic demand including net exports for each jurisdiction and each period ($NX_{AB,t}$ and $NX_{US,t}$); thus, the demand constraint is

$$\sum_G Gen_G - load_t - NX_{AB,t} - NX_{US,t} \geq 0, \forall t. \tag{2}$$

BC's electricity is predominately generated by large-scale hydroelectric plants, which allow a certain level of control over reservoir levels and the amount of water released through turbines. Hydroelectric power generation at plant h is given by:

$$Gen_{t,h} = \frac{9.81 \times \eta \times H_{t,h} \times q_{t,h} \times d}{3{,}600 \times 1000}, \forall t, \tag{3}$$

where η is the efficiency of a Francis turbine, $H_{t,h}$ is the beginning-of-period head height (m), $q_{t,h}$

is the rate of flow through the turbine (m^3/s), and d is the number of hours in period t. The equation is divided by 3,600 to convert seconds to hours and by 1,000 to convert power generation from kWh to MWh. For simplicity, the beginning-of-period head height is used instead of average effective head height. Both $H_{t,h}$ and $q_{t,h}$ are choice variables, and following Loucks et al. (1981), equation (3) is linearized for tractability using:

$$q_{t,h}H_{t,h} \approx q_t^0 H_t^0 + q_t^0(H_t - H_t^0) + (q_t - q_t^0)H_t^0 = q_t^0 H_t + q_t H_t^0 - q_t^0 H_t^0, \tag{4}$$

where H_t^0 and q_t^0 are the reservoir's average head height and average outflow, respectively, gathered from hydrometric data. Following Jha et al. (2008), head height is then related to reservoir volume by

$$H_{t,h} = Hmin_h + \sqrt{Vol_{t-1,h}/R_h}\,, \forall t, \tag{5}$$

where *Hmin* is the minimum regulated head height and R_h is a reservoir-specific constant derived by solving equation (5) using the maximum regulated head heights and reservoir volumes. Constraint (5) is nonlinear, which requires the use of a nonlinear programming algorithm; the problem may be converted to a linear program by assuming reservoir dimensions and replacing (5) with the standard formula for the volume of a rectangular prism.

Furthermore, the change in reservoir volume is determined by inflows, outflows and the volume of water spilled due to reaching reservoir storage capacity. This constraint is formulated as

$$Vol_{t,h} = Vol_{t-1,h} + \left(i_{t,h} - q_{t,h} - s_{t,h}\right) \times 24 \times 3600, \forall t, \tag{6}$$

where volume is measured in m^3 and inflow (i), outflow (q), and spillage (s) are measured in m^3/s, but converted in (6) to daily flows. Here, inflows are deterministic and available from hydrometric data, although stochasticity can be handled using stochastic dynamic programming models (see Jha et al. 2008).

Finally, BC Hydro sets targets for end-of-year reservoir levels. Specific details are unavailable, so arbitrary year-end reservoir levels are specified as a proportion (*e*) of initial storage levels. The volumes modeled are the live storage volumes:

$$Vol_{T,h} \geq Vol_{1,h} \times e_h,\ T = 366 \tag{7}$$

Transversality condition (7) is also important to prevent reservoir volumes from dropping to unrealistically low levels by year-end. Since the objective function does not recognize the value of storing water beyond the terminal period, reservoir volumes will naturally be drawn to zero without this constraint. As an alternative to (7), one might include a value function that captures the future profits from the potential energy stored at time *T*.

Currently, the Peace and Columbia hydroelectric systems are modeled independently, while the power generation from the remaining hydro plants is assumed to be functions of annual power generation and river inflows (i.e., annual generation multiplied by the daily inflow divided by the total annual inflow in 2008). Additionally, thermal generation is modeled as a single type, with no identification of individual plants. Biomass, biogas and other generation methods play a minor role in BC's electricity infrastructure, and have not been modeled.

Trade between BC and Alberta is simply limited by an assumed intertie capacity of 800 MW, while the intertie capacity between BC and the U.S. is 2,000 MW. We include a 7% transmission loss on both interties. These two constraints can be written as:

$$\text{Import}_{\text{AB,t}} + \text{Export}_{\text{AB,t}} \leq 800 \times 24 \tag{8}$$

$$\text{Import}_{\text{US,t}} + \text{Export}_{\text{US,t}} \leq 2000 \times 24 \tag{9}$$

5. Results and Discussion

Like river inflows, the model treats energy demand as deterministic. In reality, BC's energy demand changes with population, weather and economic activity. Demand from large firms is particularly volatile since consumption is influenced by export markets and world commodity prices. Because customer rates are based on average cost, which may be significantly lower than the market price of electricity, there is exposure to price risk on all consumer demand in excess of planned load (BC Hydro 2008c). This is not considered in the model.

The model was programmed to permit consideration of various scenarios. The reliability of hydro generation in BC is most impacted by weather conditions, especially precipitation and snowpack; thus, an option is included to indicate drier or wetter than average weather conditions. Energy consumption and the generating mix are the primary factors influencing energy costs. The generating mix is influenced by energy prices, inflows, reservoir level and demand. A summary of the model import and export prices used in the model was provided in Table 3, while model results are summarized in Table 4.

Under normal demand conditions, and in the absence of thermal generation, the model results indicate that BC will need to rely on imports to meet internal load even when exports are restricted to zero, which is what we would expect given that provincial installed hydroelectric capacity nearly matched peak load in a below average water year. Nearly 12.4% of the province's electricity demand must be imported from the U.S. and Alberta. By increasing the year-end reservoir targets, possibly due to the anticipation of drought, higher demand or higher energy prices in the future, energy costs increase as additional imports are required to meet domestic demand.

Table 4: Generation by Type for Various Scenarios

Scenario	Hydro	Site C	Thermal	Imports	Exports
2008 Demand, No Thermal, No Exports, VolRes=50%	87.6%	n/a	n/a	12.4%	n/a
2008 Demand, No Thermal, No Exports, VolRes=100%	77.1%	n/a	n/a	22.9%	n/a
2008 Demand, Thermal, No Exports, VolRes=100%	89.2%	n/a	1.2%	9.6%	n/a
2008 Demand, Thermal, No Exports, VolRes=50%	76.6%	n/a	0%	23.4%	n/a
Oil/Gas Demand, Site C, VolRes=50%	78.2%	7.7%	1.8%	5.9%	6.3%
Oil/Gas Demand, Site C, VolRes=100%	65.6%	5.5%	8.1%	15.4%	5.4%
Site C, Oil/ Gas, No Thermal No Exports VolRes=50%	78.8%	8.8%	n/a	12.3%	n/a
Site C, Oil /Gas, No Thermal No Exports VolRes=100%	70.3%	6.1%	n/a	23.6%	n/a

With the current set of hydrometric data and prohibiting trade with the U.S., it is not possible to decommission any of the thermal plants, even when reservoir live storage volumes are permitted to fall to 50% of their starting values at the end of the year – thermal generation is still required for a few days a year. With electricity trade, BC's thermal plants can be made redundant. The effect of increasing end-of-year reservoir targets is to increase imports, even though it is still possible to keep expensive thermal production off-line. Yet, from a policy perspective, the analysis suggests that BC cannot meet its goals of energy self-sufficiency in conjunction with decommissioning of the Burrard power plant. To achieve self-sufficiency under these conditions, BC will require imports from the U.S. and/or Alberta.

Oil, gas and mining developments are expected to increase provincial demand by 3,162 GWh/year and will further strain BC's electricity generating system. In the absence of trade and thermal generation, BC would be unable to meet the increased demand regardless of how low reservoir levels are permitted to fall. One solution to the energy deficit is the proposed Site C hydroelectric facility on the Peace River. Adding Site C as a 1,098 MW run-of-river facility makes thermal generation unnecessary, although electricity trade remains essential. However, as the end-of-year reservoir capacity restriction increases from 50% to 100%, the province's dependence on imports grows from 1.3% to 19.5%. This amounts to nearly 13,000 GWh of electricity. Even under the most aggressive power call plans, it is unlikely that the province could generate that amount of electricity from independent power projects; the self-sufficiency goal becomes even more elusive if precipitation is lower than expected.

6. Conclusions

Our results demonstrate that British Columbia can meet its domestic electricity demand based on the current generating and transmission configurations, although this requires the use of output from thermal power plants. However, if thermal units are decommissioned, imports of electricity will be needed to meet load, thereby violating the province's self-sufficiency targets and also effectively exporting CO_2 emissions associated with gas and/or coal burning to neighboring jurisdictions (Alberta or the U.S.). Assuming full reservoirs at the beginning of the year, the extent to which the province will need to rely on imports depends on the extent to which it will permit reservoir volumes to decline throughout the year – the extent to which BC Hydro is willing to compromise its ability to meet next year's load. The tighter the constraint is on year-end reservoir volumes, the greater will be the province's dependence on imports to meet load. This would be exacerbated if water inflow volumes were reduced due to drought.

British Columbia and Alberta have an entrenched trading relation that, with greater transmission intertie capacity, could improve the economic and environmental situations of both provinces (e.g., see Scorah et al. 2012). With high levels of wind penetration into its grid, Alberta faces greater grid instability. The inability of slow ramping thermal generation to react to wind ramping events leads to grid reliability issues in that province, while British Columbia faces a shortage of energy. Increasing the capacity of the Alberta-BC intertie and improving scheduling practices would benefit both provinces. Alberta could receive electricity from BC's fast-ramping hydroelectric facilities to counteract wind ramping events, while BC could import excess wind and/or thermal power supply from Alberta and store water for future production.

At present, there is little (or no) political will to increase transmission between the provinces, partly because Alberta's own generators earn more revenue via higher Pool prices when imports are restricted. However, Alberta has little incentive to increase the intertie capacity because BC is currently able to collect the rents associated with its ability to store energy; BC buys power when Alberta Pool prices are at their lowest level and sells it when prices are high. When prices are low, there is excess wind and/or coal-fired electricity in the Alberta grid; while wind power can easily be curtailed (leading to wasted renewable energy), output from coal plants can be reduced quickly enough only at high costs, which operators try to avoid even by dumping power to another jurisdiction are lowest prices. Thus, BC has historically received a much higher average price compared to all other generator assets in the Alberta market.

The recently-constructed 300 MW transmission intertie that runs from Lethbridge, Alberta, to Great Falls, Montana, will give Alberta options other than trade with BC. However, given the nature of the Alberta system and opportunities for generating wind east of the Rocky Mountains and energy storage facilities in British Columbia, there are clear benefits to both provinces, if only they can come to an agreement for sharing the rents that greater intertie capacity can create. Unfortunately, this might also require an opening up of BC's electricity sector and possibly scrapping the notion of self-sufficiency.

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