System Wide Cost Effectiveness of Large Hydro Projects: British Columbia's Site C Dam*

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Abstract

English:

The Site C hydroelectric project is an 1100-Megawatt hydroelectric facility under development on the Peace River in British Columbia. Construction costs for the project are currently estimated to be $16 billion. The project has been criticized for its high cost and the impacts it will have on the river system, including the flooding of land to establish the reservoir. Project proponents argue that Site C will provide low-carbon electricity that will help BC and Canada reach their greenhouse gas emission reduction goals. In this paper, we assess the cost-effectiveness of the Site C project using a detailed linear programming capacity expansion and dispatch model of the British Columbia and Alberta electricity systems. Our model includes hourly electricity demand data for sixteen sub-regions within BC and Alberta, hourly wind resource data for 681 grid cells in the two provinces, hourly solar irradiation data from 112 weather stations to characterize the solar resource, and a detailed hydroelectric model that accounts for the chaining of hydroelectric facilities and reservoirs within the Peace River, Columbia River, Kootenay River and Bridge River watersheds. We assess the value of the Site C project by calculating the optimal electricity system for supplying BC and Alberta electricity demand in 2030 both with and without the presence of the Site C project. Our model simulations reveal that the value created by the Site C project is unlikely to exceed its total cost. At the time of writing, the avoidable costs that would be saved by cancelling the Site C project total $5.8 billion. We find that the value created by completing the Site C project only exceeds the avoidable costs in scenarios where BC and Alberta coordinate electricity markets, build additional transmission capacity, and aim for 80-100% decarbonization of their electricity systems.

Français:

Le projet Site C est une centrale hydroélectrique de 1 100 mégawatts en cours de développement en Colombie-Britannique. Les coûts de construction du projet sont actuellement estimés à 16 milliards de dollars. Le projet a été critiqué pour son coût élevé et les impacts qu'il aura sur le système fluvial, y compris l'inondation des terres pour établir le réservoir. Les promoteurs du projet soutiennent que le Site C fournira de l'électricité à faible émission de carbone qui aidera la Colombie-Britannique et le Canada à atteindre leurs objectifs de réduction des émissions de gaz à effet de serre. Dans cet article, nous évaluons la rentabilité du projet Site C à l'aide d'un modèle détaillé d'expansion de la capacité pour Colombie-Britannique et Alberta. Notre modèle comprend des données de demande d'électricité horaire pour seize sous-régions de la Colombie-Britannique et de l'Alberta, des données horaires sur les ressources éoliennes pour 681 cellules du réseau dans les deux provinces, des données d'irradiation solaire horaire de 112 stations météorologiques pour caractériser la ressource solaire et un modèle hydroélectrique détaillé tient compte du chaînage des installations hydroélectriques et des réservoirs dans les bassins hydrographiques de la rivière de la Paix, de la rivière Columbia, de la rivière Kootenay et de la rivière Bridge. Nous évaluons la valeur du projet du site C en calculant le système électrique optimal pour répondre à la demande d'électricité de la Colombie-Britannique et de l'Alberta en 2030 avec et sans la présence du projet du site C. Nos simulations de modèles révèlent que dans le cadre des politiques actuelles du secteur de l'électricité, le projet du site C n'est pas rentable. Nous constatons que la valeur créée par le site C ne dépasse ses coûts que dans les scénarios où la Colombie-Britannique et l'Alberta coordonnent les marchés de l'électricité, renforcent la capacité de transport et s'efforcent de réduire les émissions de gaz à effet de serre nettement en deçà des niveaux de référence.

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List of Abbreviations

AB	Alberta
AESO	Alberta Electric Systems Operator
BC	British Columbia
$CAD	Canadian dollar
CCS	carbon capture and storage
GHG	greenhouse gas emissions, as measured by CO_2 equivalents based on 100 year global warming potential.
km	kilometer
kv	kilovolt
MW	megawatt
MWh	megawatt-hour
NPV	net present value
O & M	operation and maintenance
WECC	western interconnection
/ yr	per year

List of Symbols

i	Index of generation facilities
h	Index of hours
G_{ih}	Generation from facility i in hour h
η_i	Efficiency of hydroelectric facility i.
g	Growth rate of savings. Savings are projected for a calibration year and then extrapolated to other years based on an assumed growth rate.
r	Discount Rate (used to calculate the present value of savings).
π^X	Net revenue/costs associated with British Columbia to US exports/imports. (Appendix)
P	British Columbia to US Equilibrium Trade Flow Price. (Appendix)
X^h	British Columbia to US Equilibrium Trade Flow. (Appendix)
c_1^h, c_2^h, c_1^f and c_2^f	general form cost function parameters for home (h) and foreign (f) jurisdiction. (Appendix)
Q^h and Q^f	Internal load in the home (h) and foreign (f) jurisdiction. (Appendix)
δ	Dummy variable indicating the direction of power flow on the British Columbia to US intertie. $\delta = 1$ when exporting and $\delta = -1$ when importing. (Appendix)
τ	A scalar representing trade costs (including line loss) on the British Columbia to US intertie. (Appendix)
$v_{j,h}$	A constant unit cost for import or export flows (realized or not) in hour h and with magnitude corresponding to a fixed interval (or "bin") defined by $j \in \{-2500\,(500)\,3000\}$. (Appendix)

1 Introduction

The electricity industry around the world is in a period of transition. Concerns about climate change have caused substantial reductions in coal generator additions and capacity factors in developed countries. Rapidly falling prices for solar and wind generators have led to dramatic capacity expansions for these two technologies. In North America, low natural gas prices have helped natural gas to displace coal. Partly as a result of these trends, the greenhouse gas (GHG) intensity of the electricity sector has fallen rapidly over the past decade, in both Canada and the United States.

While the overall GHG intensity of electricity generation is falling, large-scale low carbon electricity generation projects still face substantial economic challenges. Nuclear energy is the largest low-carbon source of electricity generation in the United States at 20%, and the second-largest in Canada at 15%. However, there has been no nuclear plant addition in decades in either country, and a number of existing plants have closed in recent years. Hydroelectric generation is the largest source of Canada's electricity at 61% and accounts for about 7% of electricity generated in the United States. However, like nuclear, there have been few investments in large scale hydroelectric facilities in recent years.[1]

While there has been a dearth of new investments in large-scale hydroelectric and nuclear plants in the last decade, there are a number of large hydroelectric projects in Canada that are nearing completion. These include the Keeyask hydroelectric generating station in Manitoba, the Muskrat Falls generating station in Labrador, and the Site C hydroelectric project in British Columbia (BC). Each of these projects has proven controversial for a number of reasons. Particular concern has been raised regarding the cost effectiveness of these projects. For example, Goulding and Leslie (2019) and Hendriks et al. (2017) compare the costs of these facilities with alternative generation sources, and find that the large hydro-electric plants are substantially less cost effective than a combination of on-shore wind and natural gas combined cycle plants as well as demand side management. Moreover, they note that the conclusion is robust to the inclusion of a carbon tax on natural gas fuel, and that the conclusion applies even when sunk costs, related to already-incurred expenditures on in-construction hydroelectric facilities, are ignored.

[1] Canada has added about 7,500 MW of hydroelectric capacity over the past decade, but the vast majority of this is in small run-of-river projects. The Romaine hydroelectric project in Quebec, completed in stages between 2014 and 2017, is an exception.

In this paper, we take up the question of the cost-effectiveness of these large scale low carbon investments, by focusing on the case of the Site C hydroelectric project. Site C consists of a 1,100 MW generating station on the lower Peace River, which makes use of a purpose-built reservoir as well as the existing upstream Williston Reservoir. In 2018, costs for the project were estimated at $10.7 billion, and project completion was expected in 2024 (BC Hydro, 2020b, 2018).[2] In late December 2019, ongoing project analysis identified the need to construct previously unplanned foundation enhancements to ensure sufficient geological stability below the Site C project's powerhouse, spillway, and future core areas. These concerns prompted the Government of British Columbia to appoint Peter Milburn to review the project and provide the Government with advice on its continuation.[3] In February of 2021, the BC government announced a revised cost for the Site C project that took into account the work required to address the geological issues. The updated (February 2021) cost forecast now sits at $16 billion to complete the Site C project (Kurjata and Bains, 2021). The updated forecast includes $10.2 billion in sunk and unrecoverable costs implying a completion cost of $5.8 billion (Kurjata and Bains, 2021). With these new cost figures in hand, the BC Government committed to stay the course and complete the Site C project.

Site C generates value by displacing the costs associated with other sources of generation. For the Site C project to produce a net benefit to society it needs to deliver a present value in excess of its $16B budget. But for Site C to make sense on a go-forward basis, the present value of its output need only be greater than the $5.8B in avoidable completion costs.

Figure 1 shows the levelized cost of energy from the Site C project compared to other generation options in the region. The conclusions from this figure are in line with that of Goulding and Leslie (2019) and Hendriks et al. (2017), and help to explain concern over cost inefficiency of the Site C project, as well as the overall low investment in large hydro and nuclear facilities in Canada. Notably, the Site C large hydro project appears to be almost four times as expensive as wind, more than twice as expensive as solar, 60% more expensive than natural gas combined cycle facilities (even taking into account a $170/t carbon price), and 30% higher than the cost of nuclear generation per megawatt-hour (MWh) of electricity generated.

However, the simple comparison in Figure 1 omits three factors which could have

[2] The project budget was previously increased in 2018 from $8.8B to $10.7B to account for unanticipated cost pressures.

[3] BC Hydro is a Crown corporation owned by the Province of British Columbia.

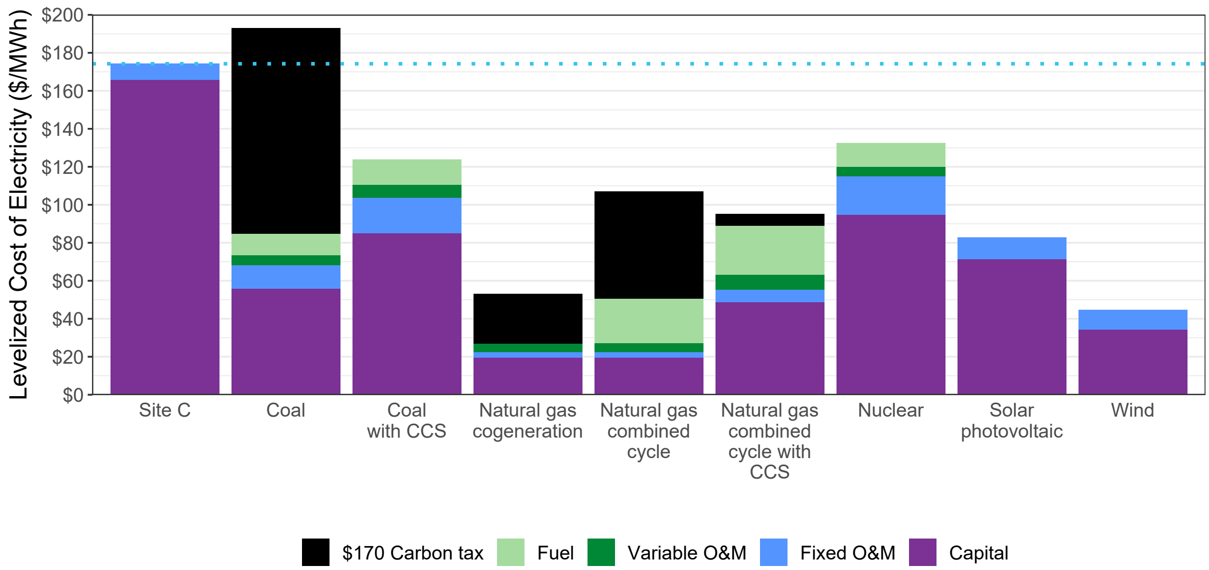

Figure 1: Comparison of levelized cost of energy.

This table represents cost assumptions from i) BC Hydro (as reported by Kurjata and Bains (2021)) for Site C, ii) EIA (2020) for Natural Gas combined cycle with CCS and iii) Lazard (2019) for all other generation technologies represented. However we modify the calculations for solar, assuming a capacity factor of 14% to represent calculated capacity factors in southern Alberta. These levelized costs also include a $170/tonne carbon tax and account for the federal government's output-based pricing system, which provides emissions allowances for coal plants of 370 tonnes/GWh in 2030.
Note that capacity factors are endogenous in our model so the levelized costs in our modeled results may differ from those shown in Figure 1.

material implications for the conclusions. First, as is well-known, the levelized cost of energy may not indicate the relative cost effectiveness of different supply options since not all options are perfectly dispatchable (Joskow, 2011). Notably, wind and solar are constrained by the availability of the underlying resource. While these renewable sources of electricity can produce electricity at a low per-unit cost, they may not produce when required. In contrast, natural gas units can be quickly ramped up or down in response to load changes, while large hydroelectric facilities can be dispatched quickly and provide long-term reservoir storage. These dispatchable sources thus provide additional capacity value in addition to the value of energy they produce. Second, the comparison of the levelized cost of different supply options does not reflect the suite of decarbonization policies necessary for reaching climate change goals or the broader policy environment. Third, the levelized cost of energy is a simple comparison of costs that does not take system constraints, such as transmission capacities, into consideration. Properly accounting for these system constraints is likely to change the relative merits of different supply options and could lead to substantial changes in assessments of their relative cost effectiveness.

In the modelling exercise below we conduct a cost-effectiveness analysis that accounts for these three factors and therefore overcomes the deficiencies of a simple LCOE comparison. We do this using the Site C hydroelectric project as a motivating case study. While we draw important conclusions about the Site C project, the broader goal of the paper is to shed light on the cost effectiveness of large-scale, centralized, low-carbon generation sources in a world that is aiming for rapid decarbonization of the electricity sector.

We conduct our analysis using a purpose-built linear programming optimization model of the joint British Columbia and Alberta electricity systems, which also reflects electricity trade with the United States. We choose to jointly model Alberta and British Columbia because the electricity systems in these two regions are already integrated through trade, and there are prospects for increased integration, particularly as a decarbonization strategy. We exclude the rest of Canada from our analysis as, currently, there are no major links between the Alberta electricity system and Saskatchewan to the east. British Columbia and Alberta are also the only two Canadian provinces operating within the Western Interconnection (WECC). Narrowing our geographic focus allows for a higher resolution representation of the electricity network within this region.

Our model is resolved at an hourly interval, and optimizes the dispatch of the electricity system at this temporal resolution to minimize system costs over an entire year. This is important, given the substantial seasonal and intra-day variation in the availability of renewable resources important for the generation of electricity, as well as potential long-term storage of energy in hydroelectric reservoirs. Our model is also resolved at a relatively fine geographic scale. We model the availability of solar and wind resources at roughly a 60km grid-scale resolution, which allows us to capture the substantial heterogeneity in the availability of resources across space. We also model the main hydroelectric generation facilities in the region (including the Site C facility in scenarios where it is present). Our hydroelectric model allows us to capture how water availability varies over the year, and decisions about when to release water from reservoirs. Moreover, we model the transmission of electricity, both within and between provinces, by dividing each province up into a number of load balancing areas. In addition to modeling the optimal dispatch of electricity over an entire year, we also co-optimize the investments in new supply of electricity generating capacity as well as new transmission capacity.

We use the model to solve for the optimal lowest cost investment and operation of the joint British Columbia and Alberta electricity system in a scenario in which the Site C hydroelectric facility is built, and compare to another scenario without the project. Comparing these two scenarios yields insights into the value and environmental impact of the Site C project, taking into account system-wide responses in investment and dispatch. We examine how the comparison changes as a result of a changing policy environment, with particular focus on policies related to expanded electricity transmission between Alberta and British Columbia, and related to decarbonization policies.

We find that under a scenario with current policies (forecast to 2030), including the required phase-out of coal-fired generating stations and other stylized representations of current policies like carbon pricing, the Site C facility appears uneconomic.[4] We use our model to estimate that the total present value of electricity output from Site C is approximately \$2.76 billion in today's dollars. This value is estimated by determining the difference in total electricity system costs in a scenario without Site C compared to a similar scenario in which the Site C project is built holding other assumptions constant. It thus includes both the value of energy from Site C as well as the value of dispatchability and storage. The present value created by Site C is substantially less than its capital cost of \$16 billion, and also less than the avoidable costs of \$5.8 billion (Kurjata and Bains, 2021). This scenario is similar to the scenario analyzed by Goulding and Leslie (2019), and our conclusions are likewise similar: if current policies are to be maintained, the Site C project was uneconomic from the start, and remains uneconomic today, even after netting out the \$10.2 billion sunk expenditure.

Under more stringent decarbonization scenarios, the value of the Site C project is increased, because it provides dispatchable zero emission electricity as well as some energy storage, both of which are crucial for a low- or zero-carbon electricity system. The additional value of Site C through this mechanism is modest except at very high decarbonization scenarios. Notably, in a complete decarbonization (100%) scenario, our model suggests that the value created by Site C increases to \$12.4 billion in present value. This value exceeds the avoidable cost as of February 2021, but does not exceed

[4]We model policies including a \$50/t CO_2 price on emissions and a halt to new natural gas generation stations in British Columbia, which proxies for the Clean Energy Act, and find that the combined GHG emissions from the British Columbia and Alberta electricity sectors would be approximately 23 Megatonnes at \$50/t CO_2 in 2030. This is a 20.8% reduction from a scenario with only the coal-fired power phaseout. In future work we will model the decarbonization impact of the current planned 2030 policy of \$170/tonne carbon price.

the total cost of the project. Importantly, this conclusion is sensitive to the possibility of building new inter-provincial transmission between British Columbia and Alberta; without new transmission links between the provinces, the value of Site C remains well below its cost even in a deep decarbonization scenario.

The following section of the paper describes the purpose-built electricity system model that we use to come to these conclusions. Section 3 describes the scenarios that we simulate using the electricity system model, and section 4 provides detailed results that we draw from the simulations. Section 5 concludes.

2 Model and data

We build a linear programming optimization model of the linked British Columbia and Alberta electricity systems. Our model is based on the Canada-wide model used in Dolter and Rivers (2018), with further disaggregation to better capture salient geographical constraints in the region as well as increased detail in hydroelectric modeling and international trade. In this section we briefly describe key features of the Dolter and Rivers (2018) model as well as the distinguishing modifications we make to it in this analysis. Interested readers are directed to the earlier work for more detail.

The model co-optimizes the investment in new generation, transmission, and storage facilities, as well as the dispatch of these technologies and transmission between regions in the model in order to meet electricity demand on a continuous (hourly) basis in all regions. The model chooses investment and dispatch in order to minimize the total annual cost of the joint British Columbia and Alberta electricity systems, subject to a number of constraints. The key constraints include:

- Electricity supply must be greater than or equal to demand in each hour and each balancing area (defined below);
- Hourly dispatch from each technology in each balancing area is less than or equal to available capacity;
- Hourly transmission between balancing areas is less than or equal to available transmission capacity;
- Hydroelectric facilities must adhere to operational constraints such as stock-flow dynamics, minimum streamflow requirements downstream from facilities, and maximum storage constraints for reservoirs;

- Thermal facilities must adhere to operational constraints such as ramping constraints;
- Dispatchable facilities are subject to a reserve requirement of 15%. This means the sum of installed dispatchable capacity – which includes hydroelectric facilities, thermal facilities, and pumped storage facilities – must exceed the hourly sum of generation from these facilities in each hour by an amount equal or greater than the reserve requirement.

2.1 Geographic and temporal resolution

The model includes British Columbia and Alberta, and is divided into 16 Economic Regions following Statistics Canada geographical definitions, 7 or which are in BC and 9 in Alberta, as illustrated in Figure 2. The Economic Regions serve as balancing areas for the electricity model. This intra-provincial disaggregation allows for representation of within-province transmission constraints, resource availability and heterogeneity, and electricity trade. Notably, we explicitly model transmission and transmission constraints *between* balancing areas. For example, moving power from Site C to load centres in the South of British Columbia and Alberta requires sufficient non-congested transmission capacity. We exogenously specify existing transmission capacity between balancing areas, and the model chooses new transmission capacity investments if these are economically justified and permitted in the specified policy scenario.

The model simulates grid operation for an entire 1-year period, in 8760 hourly increments. Investments in new generation, storage, and transmission capacity are optimized to meet demand in all hours and in all balancing areas of each province. Likewise, dispatch and transmission of available resource is co-optimized with investment. We focus on the year 2030 for our simulations in this paper. The model does not explicitly model the transition from present-day to 2030, but instead models the annual operation of the grid in 2030.

Extant generation infrastructure is exogenously specified for each of the balancing areas, drawing from the same data sources as Dolter and Rivers (2018). Extant transmission infrastructure between balancing areas is sourced from OpenStreetMap as in Medjroubi et al. (2017). Availability of solar and wind resources is based on hourly resource availability for an entire representative year from the MERRA-2 data set for wind, and the Environment Canada TMY data for solar. Solar and wind resources are

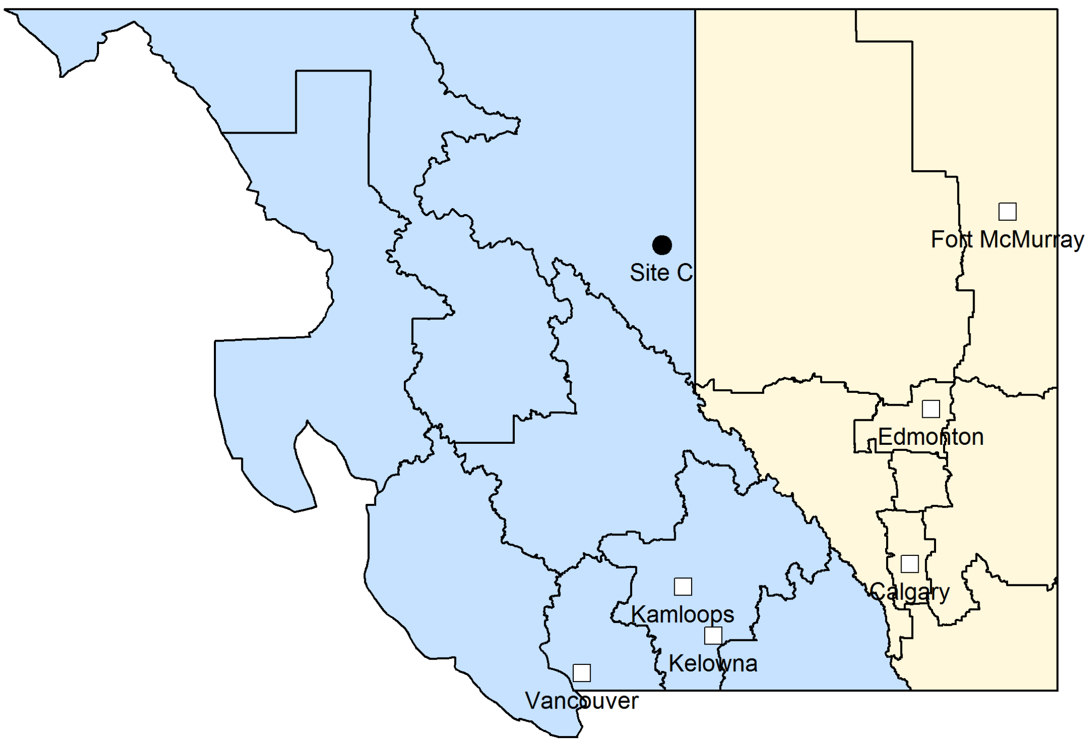

Figure 2: Economic regions and Site C location in study area.

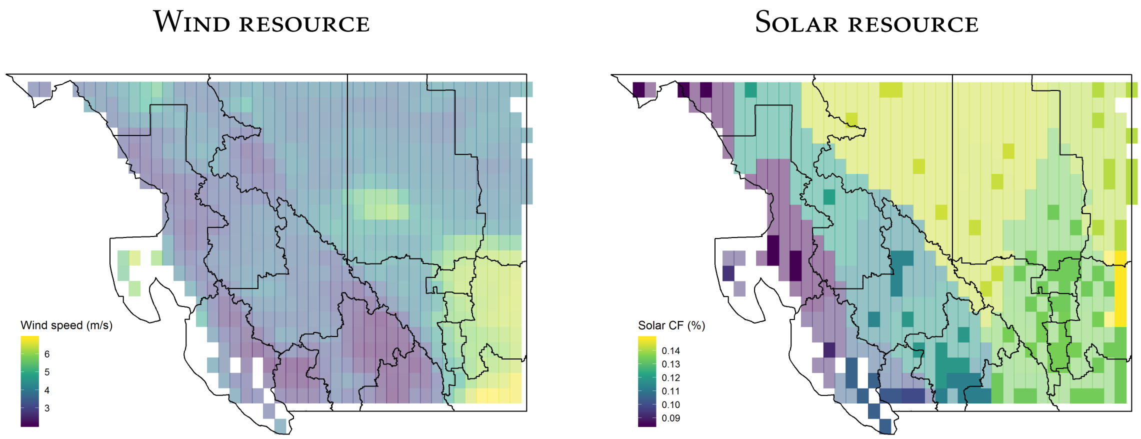

Figure 3: Solar and wind resource, annual averages.

For the solar capacity factor, we show grid cells with TMY data availability as opaque cells, and cells with imputed solar data (based on proximity to TMY cells) as more transparent.

illustrated on an annual average basis in Figure 3. On an annual basis, both solar and wind resources are concentrated in Southern and Eastern Alberta, and are more limited throughout British Columbia.

2.2 Hydroelectric generation modeling

Given the focus of the paper, we incorporate additional detail on hydroelectric generation in comparison to similar papers (Dolter and Rivers, 2018; MacDonald et al., 2016). For all major hydroelectric reservoirs in the region, we explicitly model the water availability from precipitation and snow melt, reservoir capacity and storage, and the model endogenously chooses when to release water through generating facilities or spill excess water. Each main river system that includes significant storage potential is illustrated in Figure 4, and historical average inflows to each river system are illustrated in Figure 5. Given this structure, generation from each hydroelectric generation facility i in hour h is given by:

$$G_{ih} \leq head_{ih} \times flow_{ih} \times 9.81 ms^{-2} \times \eta_i \times 1,000 kg\ m^{-3} / 1e6, \tag{1}$$

where $9.81 ms^{-2}$ is acceleration due to gravity, $1,000 kg\ m^{-3}$ is the density of water, and η_i is efficiency of the hydroelectric facility, taken to be constant. The head is determined based on the volume of water currently in the reservoir and the surface area of the reservoir and flow is endogenous.[5]

Reservoir volumes are governed by a simple accounting rule:

$$volume_{rh} = volume_{r,h-1} + inflow_{rh} - outflow_{rh}, \tag{2}$$

where the relevant inflows and outflows that connect each generator and reservoir are illustrated in Figure 4. The outflow from a reservoir includes flow through the corresponding generator as well as any spill. For a river system, the outflow of one reservoir is the inflow to the downstream reservoir, creating a dependence between subsequent reservoirs and generators on each river system. This serial dependence between generators on the same river system is important to consider in the case of Site C, which relies to a large extent on the existing Williston Reservoir. The volume in reservoirs is further constrained by the maximum drawdown specific to each reservoir, flows are constrained by minimum and maximum flow constraints, and generation is constrained by the generator capacity (see Figure 4).

In addition to the hydro-electric generators in Figure 4, which all include substantial reservoirs enabling water storage, there are also a large number of run-of-river hydroelectric projects, as well as other hydroelectric facilities with smaller storage capability throughout Alberta and British Columbia. For these facilities, we model output as an exogenous model input, based on water availability. In particular, we use historical data on run-of-river generator output to model electricity generation from these facilities. Our model captures generation from existing facilities, but does not allow new hydroelectric facilities to be constructed endogenously in the model. The generation from all hydroelectric reservoirs is allocated to the balancing region in which they are located. Our model does not include the costs of water rental from hydroelectric facilities, and does not model greenhouse gas emissions released from the reservoir or any social costs of hydroelectric or other facilities.

2.2.1 Site C hydroelectric project

Our motivating aim is to evaluate the system-wide costs and benefits associated with building the Site C hydroelectric generation facility. We take the total cost of the facility to be $16 billion based on the February 2021 estimate that includes costs related

[5]Because multiplying the head by the flow creates a non-linear equation, in the model, we break 1 into two separate constraints, the first of which multiplies the head by the maximum flow (a constant) and the second which multiplies the maximum head (a constant) by the flow.

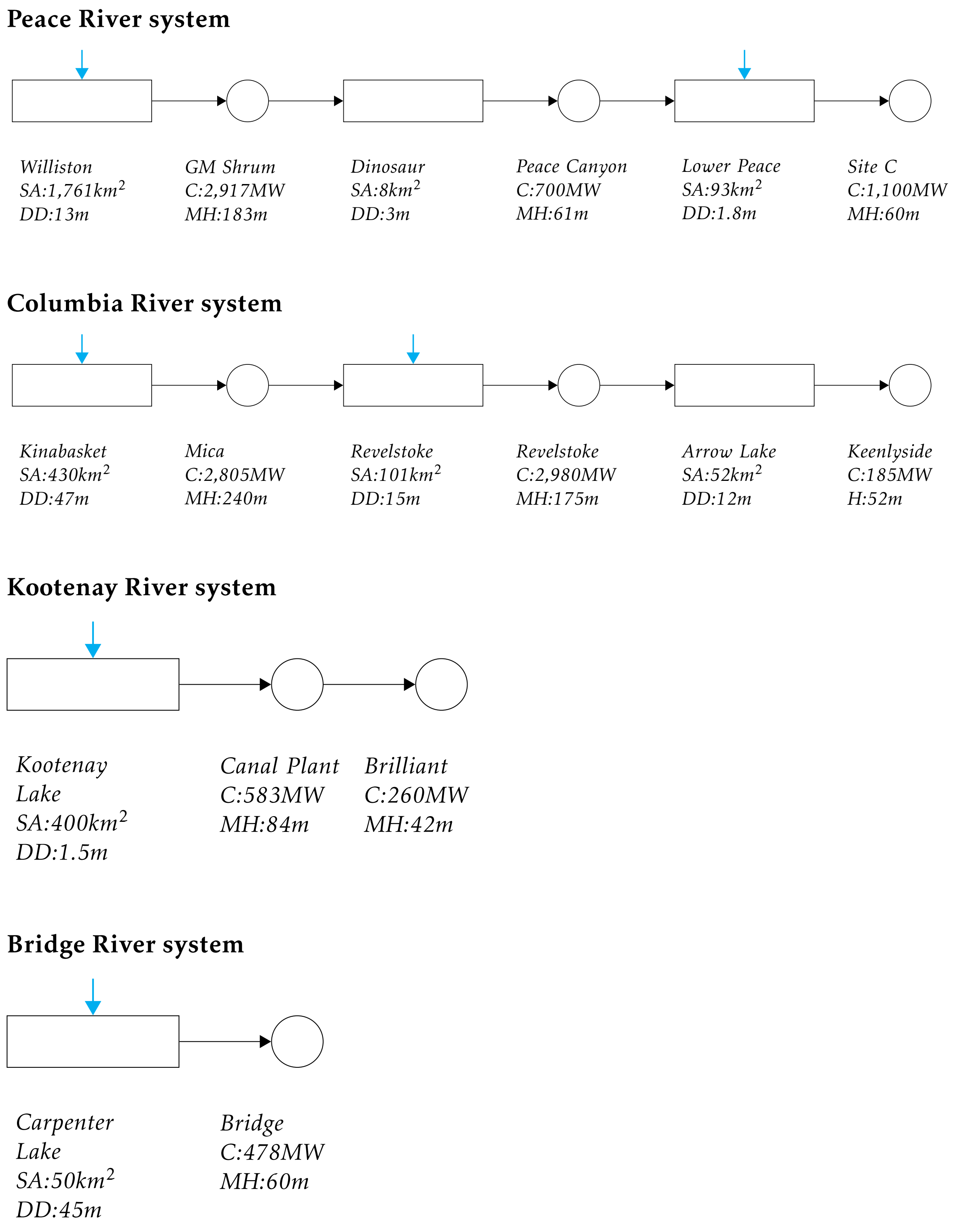

Figure 4: Schematic of main river systems with storage.

Blue arrows indicate main water inflows to each river system. Circles indicate generating stations and are characterized by capacity (C) and maximum head (MH). Rectangles indicate reservoirs and are characterized by surface area (SA) and maximum drawdown (DD).

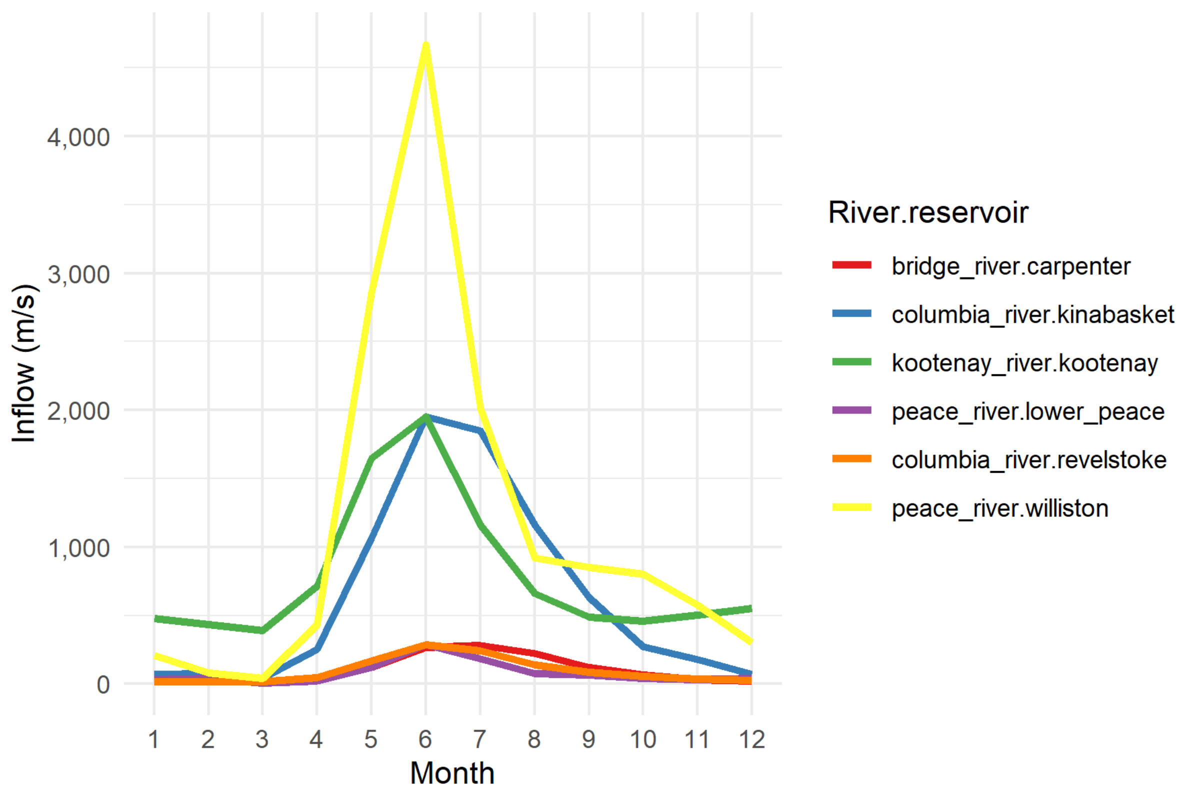

Figure 5: Monthly inflows to main river systems.

Inflow to major river systems are calculated based on historical stream gauge data from Environment Canada at https://wateroffice.ec.gc.ca/mainmenu/historical_data_index_e.html ameliorating the geological stability issues uncovered in 2019 and 2020 (BC Hydro, 2018, 2020b; Kurjata and Bains, 2021).[6]

The Site C project will provide 1,100 MW of capacity, and is expected to produce about 5,100 GWh of electricity in each year. The project is located on the Peace River, below the existing WAC Bennett and Peace Canyon dams. Because of its position on the river system, it will make use of the existing storage capacity in the Williston Reservoir, and only requires a relatively small new reservoir (see Figure 4).

In the modelling scenarios described later, we consider the electricity system with and without the construction of the Site C hydroelectric project. Once built in our model, generation from the facility (and other facilities) is endogenously determined on an hourly basis by the model by optimizing the operation of the electricity system subject to system constraints.

2.3 Electricity demand

We obtain hourly electricity demand from British Columbia and Alberta for one full year.[7] In Alberta, the electricity data is available by disaggregated AESO Planning Areas which we aggregate into Economic Regions.[8] Geographically dissagregated hourly electricity load data is not available for British Columbia so we prorate the provincial load across economic regions based on population shares. We treat electricity demand as exogenous, and do not attempt to model demand-side measures or behavioural changes. To maintain internal consistency we project regional electricity demand to 2030 using the forecast in Canada Energy Regulator (2019) by assuming proportional load growth across all hours and balancing areas in the model. This implies load growth of 1.29%/yr for AB and 1.36%/yr for BC for a total of 16.5% (AB) and 17.6% (BC) relative to the 2018 calibration year.

Figure 6 shows load duration curves (panel A) and hourly load profiles (panel B) for the two provinces. Alberta's average electricity demand is on average somewhat larger and less variable throughout the year compared to British Columbia's. This is due to Alberta's larger industrial base. Electricity demand for both British Columbia and Alberta is highest in winter and lowest in summer, although seasonal peaks are

[6]At the time of the Final Investment Decision in 2014, the cost of the Site C generation facility was estimated to be $8.775 billion. However, since that time, costs have increased as explained in the introduction.

[7]Our model uses 2018 for all benchmark data.

[8]Our aggregation is based on the concordance table in Appendix C.

more pronounced in British Columbia than Alberta.

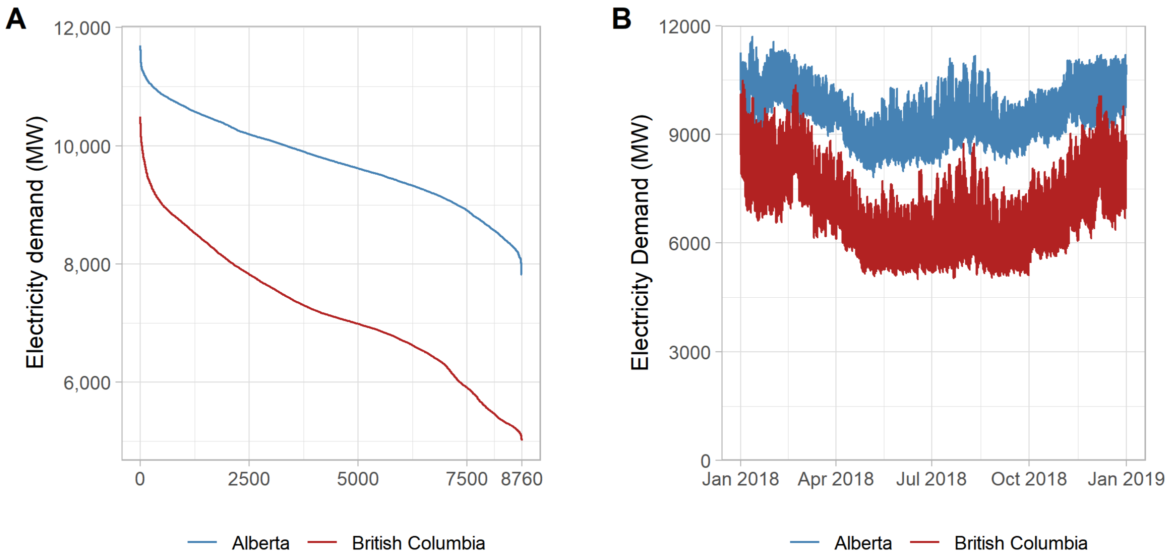

Figure 6: Electricity Demand for British Columbia and Alberta.

Panel A: Load duration curves.

Panel B: Hourly demand. (2018 demand data from AESO (2020) and BC Hydro (2020a)).

2.4 International electricity trade

We endogenize trade flows across the British Columbia to United States inter-tie to determine how the presence of Site C and GHG emissions reduction policy will impact international trade flows.

We implement endogenous trade with the US using a piece-wise linear unit-value function, which allows implementation of trade flows that are implicitly endogenous in marginal generation cost within the linear program.[9] The program implicitly defines an export-supply / import-demand function for the British Columbia and Alberta electricity system, whereas the stepped trade flow function stands in for the export-supply / import-demand function of electricity trading partners in the United States. The concept is illustrated in Figure 7. Calibration of the unit-value function is based on trade data on the BC-US intertie from 2018-2019 from the NRGSTREAM service. Details of the function and calibration are outlined in Appendix D.

[9] The piece-wise or stepped nature of the function is necessary to avoid multiplying endogenous values (unit-cost and trade flow), which would lead to a non-linearity in the model.

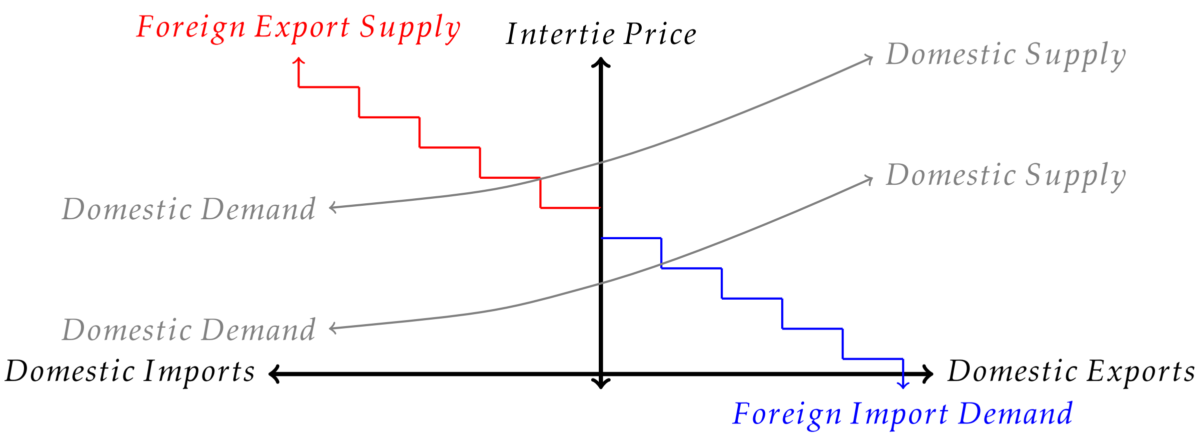

Figure 7: Stepped trade flow function.

The shape of the kinked Export Supply / Import Demand curve is calibrated from existing hourly trade-flow and intertie-cost data. The Domestic Demand / Domestic Supply curve is implicit, with the shape and height determined hourly by the Linear Program's exogenous parameters and endogenous optimization. Two Domestic Demand / Domestic Supply curves are shown to illustrate how hourly or counterfactual movements in the implicit schedule can lead to net imports or net exports.

2.5 Costs of other technologies

We choose capital costs, operations and maintenance (O&M) costs, and fuel prices to reflect the most recent published estimates (see Table 1 for a summary of our cost inputs). Costs are generally sourced from Lazard (2019). We use the mid-point of values when high and low costs are provided. We then look to EIA (2020) for the costs of technologies not present in Lazard (2019); our "waste" generation facilities are modelled using EIA (2020) biomass costs, and natural gas with carbon capture and storage (CCS) costs are sourced from EIA (2020). The operations and maintenance costs of extant hydroelectric facilities are equal to those listed for Site C in Table 1 and are sourced from Lazard (2019). Capital costs are annualized using a financing rate of 5.13%, reflecting the cost of capital estimated in Goulding and Leslie (2019), and at an amortization length equal to the expected facility life provided in Lazard (2019) or EIA (2020). US dollars are converted to Canadian dollars at the 2019 average annual USD-CAD exchange rate of 1.3269 (Bank of Canada, 2020). In Table 1, diesel generation costs are sourced from Lazard (2017) and 2017 dollars are inflated to 2019 using changes to the US Bureau of Labour Statistics consumer price index for urban consumers (US Bureau of Labour Statistics, 2020).

We use a natural gas price of \$3.6/GJ, which is the forecast price in 2030 for Alberta

(Canada Energy Regulator, 2019). We use the uranium price of $.85 USD/MMBtu provided in Lazard (2019). We assume a diesel price of $1/litre. Emissions factors for natural gas, coal, and diesel are calculated using data from Environment Canada (2014).

The model includes the possibility of constructing new long-distance transmission lines to connect balancing areas when permitted by an exognously specified policy toggle. Like generation investments, these transmission investments are endogenously determined in the model if they represent a least-cost pathway to meeting electricity demand. Costs for inter-balancing area transmission investments are sourced from GE Energy Consulting (2016), using the costs of a 345 kilovolt (kv) double-circuit transmission line with maximum capacity of 1500 MW. The transmission capital cost of $2.4 million/km for a 345 kv line is annualized using a 5.13% financing rate and a 25-year amortization period, leading to a cost of $118/MW/km/yr. Transmission costs to connect wind and solar facilities to transmission within balancing areas are also sourced from GE Energy Consulting (2016), using the cost of a 230 kv single-circuit transmission line with maximum capacity of 330 MW. Using the same amortization rate and schedule, the intra-balancing area transmission cost of $1.6 million/km is annualized and calculated to be $349/MW/km/yr.

Lastly, the model includes the possibility of building new pumped-hydroelectric energy storage facilities. We model the cost of these facilities using the description of the Marmora project included in the Trottier Energy Futures Project (2016), Table 18, p. 93. These 2016 costs are inflated to 2019 $CAD using Statistic's Canada All-items Consumer Price Index (Statistics Canada, 2020).

2.6 Alberta cogeneration

Alberta possesses significant cogeneration capacity on its provincial electricity grid. Many of these facilities generate electricity as a by-product of creating steam and process heat for bitumen extraction from oil-sands. We specify the location and capacity of cogeneration facilities by balancing area in Alberta. We then use bid data from the Alberta Electricity System Operator (AESO) to identify the amount of cogeneration capacity that is bid into the merit order system at zero dollars in each hour for 2018 (AESO, 2020). These zero-dollar bids are treated as 'must-run' hours for cogeneration capacity in the model. We assign only half of the GHG emissions created by cogeneration to the electricity sector, assuming that the other half will be assigned to the industrial operations associated with the facility. These assumptions mean that emissions from cogeneration facilities are 50% lower than natural gas combined cycle plants. In scenarios with ambitious decarbonization targets (see below), output and emissions from cogeneration plants can only be reduced below 'must-run' levels by retiring capacity. We do not model the cost implications to Alberta's oil sector of retiring cogeneration capacity.[10]

3 Scenarios

We use the model to contrast two main scenarios in the year 2030 for the joint British Columbia and Alberta electricity systems: one scenario that includes the Site C hydroelectric facility, and one that excludes it. The difference in cost and operational characteristics between these two scenarios reflects the impact of Site C. Importantly, our model determines optimal system response, both in terms of investments in transmission, storage, and generation, as well as dispatch, which differs depending on whether the Site C facility is constructed or not. This allows us to value the full benefits from the Site C project, including the energy generated as well as any benefits deriving from its dispatchability and ability to store energy.

Our baseline scenarios include the legislated constraint that requires coal-fired power plants in Canada to be retired or retrofit with carbon capture and storage (CCS) by 2030. In Alberta, utilities are choosing to retire coal plants or convert them to run on natural gas. We also model additional scenarios focused on more ambitious carbon reduction targets. Specifically, we impose a constraint on GHG emissions from the joint Alberta-British Columbia electricity system that varies from a 0% reduction to a 100% reduction relative to reference case emissions. Running these scenarios allows us to infer how the value of the Site C project is affected by decarbonization ambition. We also model scenarios in which we do not allow any new transmission to be built between British Columbia and Alberta. These 'no new AB-BC transmission' scenarios allow us to infer the importance of expanded inter-provincial transmission to the cost-effectiveness of the Site C project.

[10]Note that "retiring capacity" of cogeneration in the model could also be interpreted as operators moving cogeneration "behind the fence" such that they continue to provide steam and process heat but do not dispatch electricity to grid.

4 Results

4.1 Cost-effectiveness of Site C

We begin by evaluating the cost-effectiveness of the Site C project. Figure 8 displays the annualized cost savings generated by Site C across a range of GHG emissions reduction outcomes, with and without new transmission links between Alberta and BC.[11] These costs savings are calculated by subtracting the annual electricity system cost of a scenario that includes the Site C project, from the annual electricity system cost of a scenario that excludes the Site C project. In both cases, the rest of the generation profile is endogenously chosen.

The annual value of Site C is strongly dependent on how much decarbonization is required in the BC and Alberta electricity systems. Without any decarbonization requirement beyond the coal-fired phaseout, the annual value of Site C is estimated at only \$61M/year in our model. In these scenarios, Site C displaces new investments in natural gas combined cycle facilities, as well as the operation of these facilities. However, the model suggests that in the 0% decarbonization scenarios, building Site C instead of natural gas combined cycle facilities also requires the buildout of additional transmission capacity as well as construction of additional natural gas simple cycle units for peaking use (see Figures 18 and 19).

Between 40% and 70% decarbonization effort, the annual value of Site C is around \$200 million (\$2019 CAD). In this range, Site C displaces new investments in wind facilities as well as new generation from those facilities. Wind energy in our model has a levelized value of about \$42/MWh. Site C provides approximately 5100 GWh of electricity per year, and multiplying this levelized cost of \$42/MWh by 5100 GWh results in a value of \$214M/yr. This means that, in these scenarios, Site C is valued mainly for its generation value, and does not receive a premium for providing dispatchable capacity.

In scenarios with decarbonization effort beyond a 70% reduction in aggregate GHG emissions, Site C displaces nuclear or natural gas CCS capacity and either imports, natural gas CCS or nuclear generation. In these scenarios, the Site C project has higher value where new inter-provincial transmission is allowed. In scenarios without new inter-provincial transmission, the annual cost savings generated by Site C actually drops at high levels of GHG emissions abatement. This is likely because at GHG reductions

[11] Total costs from our model runs are presented in Appendix B.

of 80% and greater it is necessary to retire cogeneration capacity in Alberta. Without improved transmission links to BC, Site C does little to offset the cost of replacing this capacity. The replacement for co-generation capacity in Alberta is instead nuclear power, which reduces the need for Site C's firm capacity.

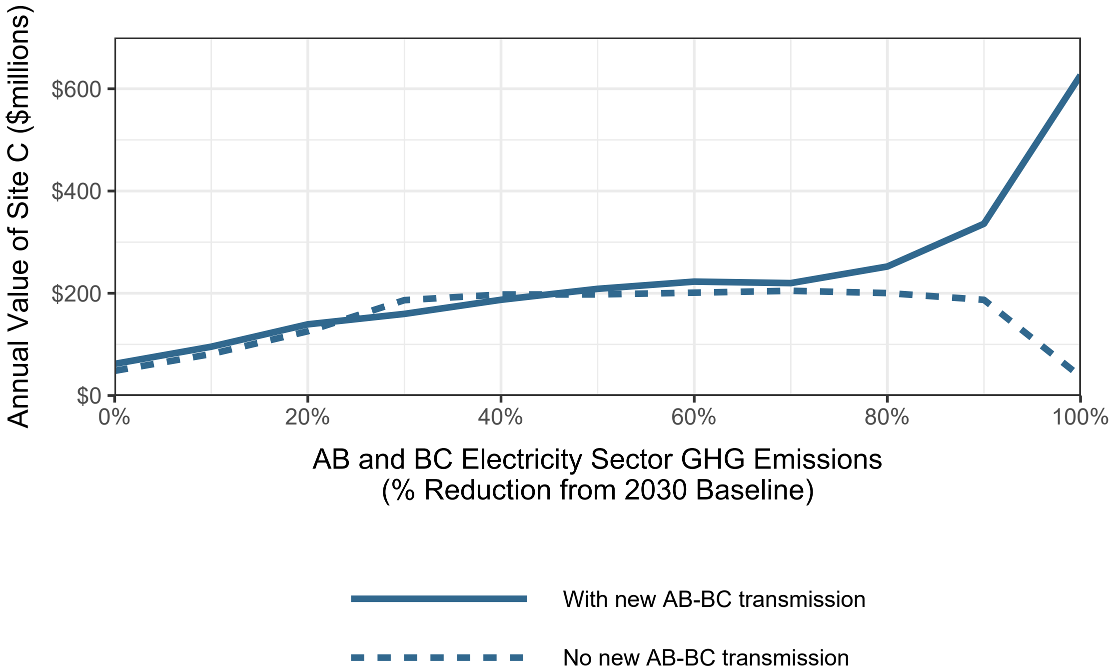

Figure 8: Annualized Cost Savings Generated by Site C

To make our results comparable to Site C's capital costs, we calculate the net present value of the stream of benefits created by Site C, assuming a facility life of 70 years and using a social discount rate of 5%. This allows us to compare our results directly to BC Hydro's Site C estimate of \$16 billion in total costs and \$5.8B in avoidable costs (Kurjata and Bains, 2021). Since our model results provide a snapshot of the value of Site C in 2030 given various scenario assumptions, we apply a growth rate to the value of annual savings created by Site C. The growth rate represents factors such as demand growth that would increase the value of Site C. We run scenarios for the year 2050, compare the value of Site C in those model runs to our 2030 values, and find that, on average, the value of Site C grows by 1.52%/year. This growth rate in value is slightly higher than the rates of electricity demand growth we assume in the model (1.29%/yr for Alberta and 1.36%/yr for BC). We provide a sensitivity analysis to our growth in value assumption in Appendix B (see Figure 15). Net present value (NPV) is calculated using the following equation:

$$\mathrm{NPV} = \mathrm{savings}_{2030}(1+g)^{-5}\left[\frac{1-\left(\frac{1+g}{1+r}\right)^{\mathrm{life}}}{1-\left(\frac{1+g}{1+r}\right)}\right] \tag{3}$$

where g represents the annual growth rate of savings (1.52%), r represents the social discount rate (5%), *life* refers to facility life, assumed to be 70 years for the purpose of this calculation, and *savings* refers to the annual savings we calculate using our model.[12]

Like Figure 8 above, Figure 9 indicates that the net benefit of Site C depends on the ambition of decarbonization efforts as well as the degree of inter-provincial transmission cooperation between Alberta and British Columbia. The value of Site C increases as GHG emissions are reduced below 2030 baseline levels. Our GHG emissions baseline includes only the phase-out of coal-fired power plants in Alberta.[13] Policies such as a \$50/tonne carbon price and BC's *Clean Energy Act* will achieve a further GHG emissions reduction of 21% relative to our baseline. At this level of decarbonization, Site C is uneconomic and should not be completed.[14] If decarbonization ambition is increased,

[12]The $(1+g)^{-5}$ term is included to start the discounting based on initial year one savings for the end of planned in-service year: 2024. The end of 2024 is 5 years prior to the model projection year 2030.

[13]We do not present results in this paper that explicitly model existing electricity policy beyond the coal-fired phaseout. Instead, we motivate GHG emissions reductions in our model beyond the baseline by setting constraints on the sum of Alberta and British Columbia GHG emissions. Our model then selects the least-cost portfolio that meets each GHG emissions constraint.

[14]In future work we will model the decarbonization impact of the \$170/tonne carbon price.

completing the Site C project produces a net present value greater than the cost avoided by cancelling the project only at GHG emissions reduction levels of 90% to 100%, and only when new transmission links can be built between Alberta and BC. At no level of decarbonization ambition is the net present value created by the Site C project greater than its estimated cost of $16B.

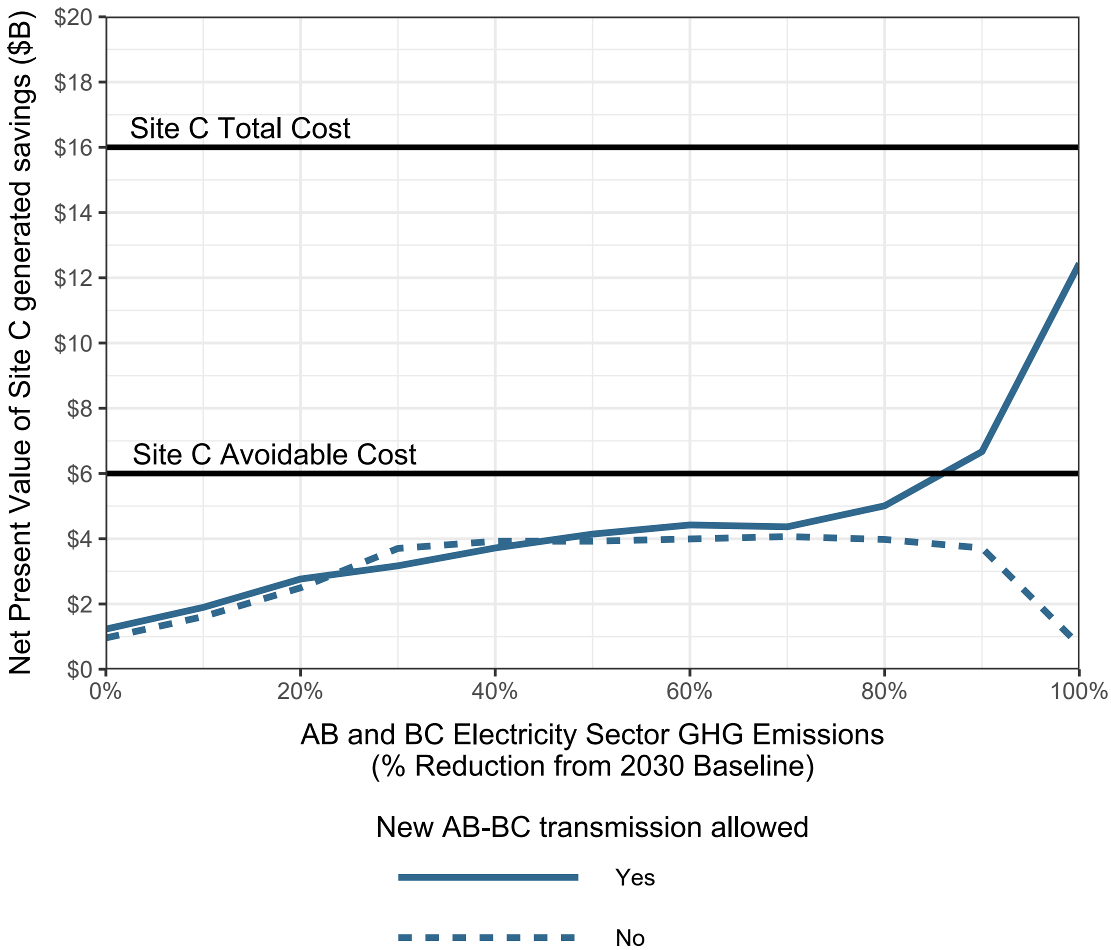

Figure 9: Net Present Value of Savings Generated by Site C

4.2 Sensitivity to Cost of CCS and Nuclear Power Plants

Our baseline estimates of the cost of constructing natural gas with CCS and nuclear plants are drawn from EIA (2020) and Lazard (2019). We use the midpoint capital cost of nuclear from Lazard (2019), and draw the cost of natural gas with CCS from EIA (2020). These capital costs may underestimate the cost of constructing CCS and nuclear plants, and, as a result, undervalue the replacement value of Site C. Realized CCS projects have been expensive. The Boundary Dam III CCS coal plant was built at a cost of $1.467 billion (in 2014 dollars) for 115 MW of capacity in Estevan, Saskatchewan (IEAGHG, 2015). New nuclear builds at the Vogtle nuclear power plant in Georgia (USA), Hinckley Point C in the United Kingdom, and Olkiluoto 3 in Finland have been subject to long delays and have run over-budget (International, 2020; News, 2021; Rosendahl and Forsell, 2019). In our sensitivity analysis we use the upper end of nuclear capital costs from Lazard (2019) and inflate the cost of natural gas with CCS by a factor of 1.78. The inflation factor for CCS is calculated by comparing the EIA (2020) capital cost of coal with CCS to the actual cost of Boundary Dam III in Saskatchewan.

Figure 10 compares our baseline results with the results from scenarios that use higher capital costs for natural gas with CCS and nuclear power plants. The value of Site C exceeds Site C's estimated total cost only in the scenario where new transmission between AB and BC is constructed and the provinces target 100% decarbonization. Even then, Site C is only marginally more valuable than its total cost. The value of Site C exceeds its avoidable cost only in scenarios that target emissions reductions greater than 70% and that allow new AB-BC transmission to be built. Site C's value remains below its avoidable cost in all scenarios without new AB-BC transmission.

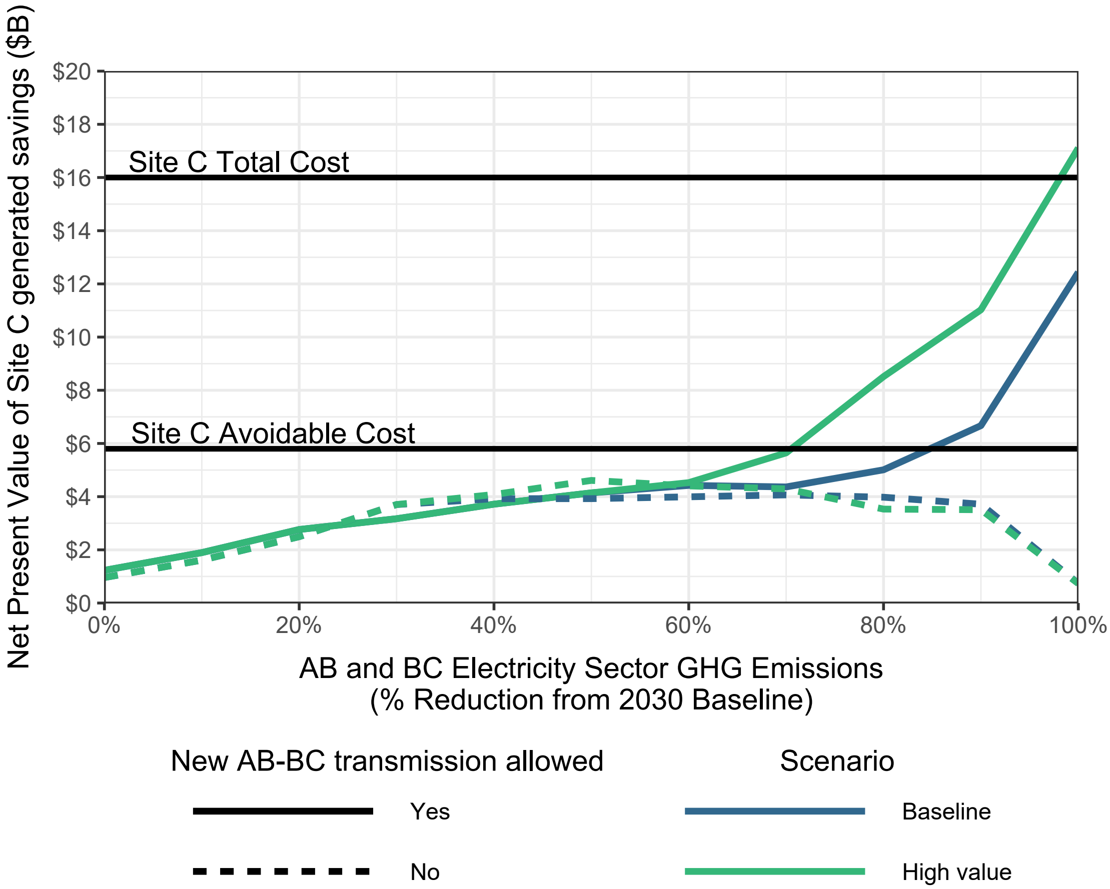

Figure 10: Sensitivity of Site C Value to the Cost of Natural Gas with Carbon Capture and Storage and Nuclear Power Plants

4.3 Changes to generation and capacity mix

The presence of Site C changes the optimal generation and capacity mix in our modelling scenarios. Figure 11 displays the changing contributions made by key technologies across a range of decarbonization scenarios, with and without Site C. The top panel shows the results when new transmission links can be built between Alberta (AB) and British Columbia (BC). The bottom panel presents generation proportions in scenarios when new transmission links cannot be built between the two provinces. A few differences are noteworthy.

First, the contribution that wind generation can make in our scenarios varies based on our transmission assumptions. When new transmission links can be built between provinces, wind energy reaches a much higher proportion of generation in Alberta. Connecting the two provinces allows BC's flexible and dispatchable hydroelectric facilities to provide balancing services; ramping up and down to balance the variability of wind energy (see also Figure 12). In this context, when Site C is present in the 100% decarbonization scenario with new AB-BC transmission, an additional 1593 MW of wind capacity is built in Alberta (see also Figures 16 and 17).

Second, natural gas combined cycle plants provide a large proportion of electricity in Alberta and BC at low levels of decarbonization ambition. As was shown in Figure 1, natural gas combined cycle plants produce electricity at the lowest levelized cost, aside from wind energy and cogeneration.[15] In scenarios with low decarbonization effort, Site C offsets natural gas combined cycle generation and investment in new combined cycle capacity. As we tighten the constraint on greenhouse gas (GHG) emissions, it is optimal to make investments in combined cycle plants equipped with carbon capture and storage (CCS). The value of Site C increases in scenarios where it offsets these higher-cost investments in CCS facilities.

Third, to achieve a zero emissions electricity sector, only technologies with zero-emissions can run. This eliminates natural gas cogeneration facilities and natural gas CCS facilities, which still produce GHG emissions, although at lower levels than facilities without CCS. Site C has higher value in the 100% decarbonization scenario with new AB-BC transmission allowed, because it offsets investment in high-cost nuclear power facilities.

Figure 16 in Appendix B shows total generation by all technologies across our

[15]Natural gas cogeneration facilities have a lower levelized cost, but are built to power industrial operations; electricity generation is a secondary benefit. For this reason we do not allow new investment in cogeneration in our modelling scenarios.

scenarios. Figure 17 in Appendix B shows the same scenarios in terms of installed capacity rather than generation, while Figures 18 and 19 present only the net changes in generation and capacity when Site C is not present in a modelling scenario.

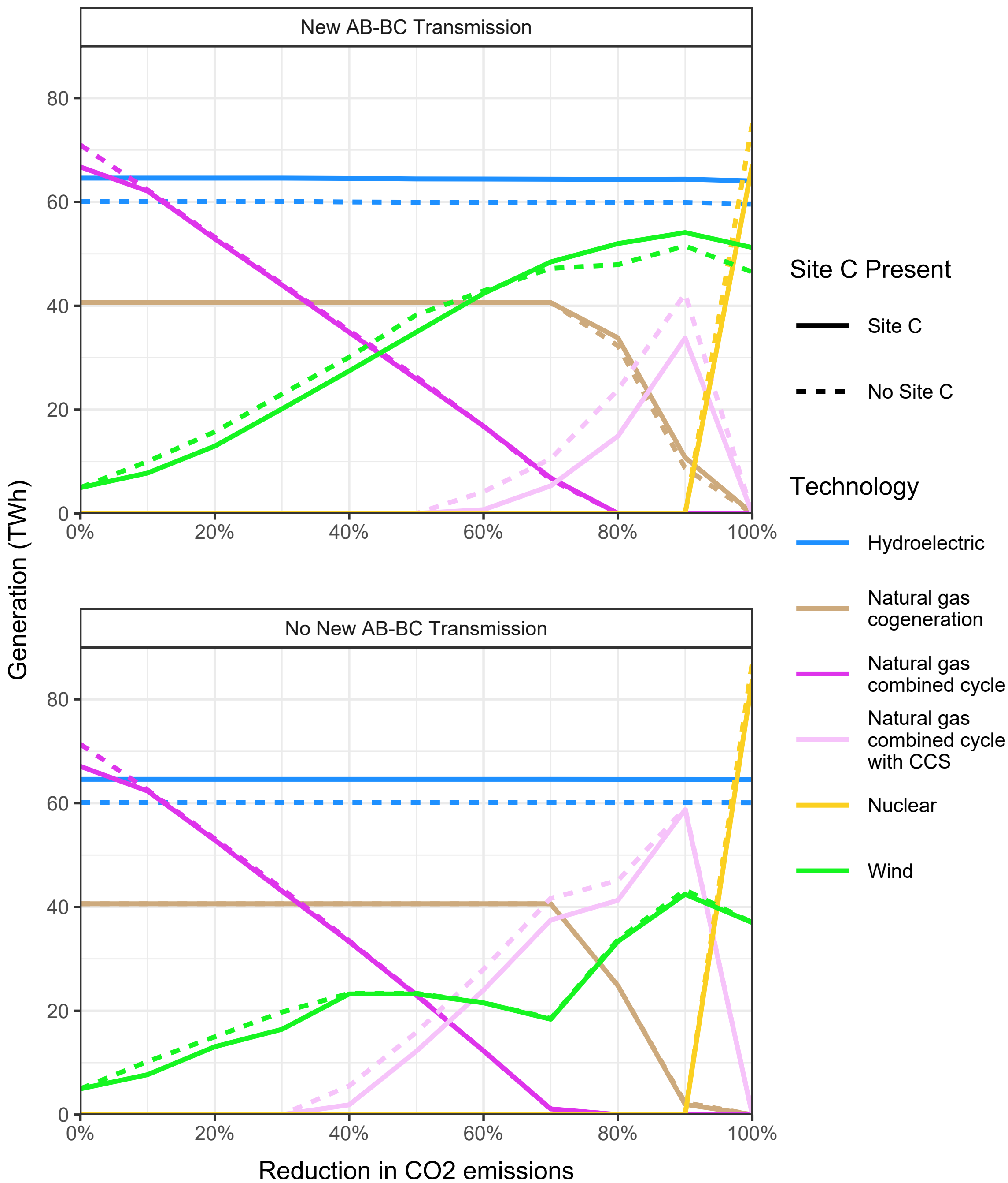

Figure 11: Electricity Generation by Key Technologies

4.4 Hydroelectricity and Wind Energy production

Wind energy can be generated at low cost in sites with strong wind resources, such as those found in southern Alberta. However, output from these wind energy facilities is variable. This variability means that systems with high wind energy penetration need complementary dispatchable generation facilities. Figure 12 presents the relationship between hydroelectric output and wind energy output in two scenarios that achieve 100% decarbonization and include new AB-BC transmission links. Each point represents the wind and hydroelectric generation combination in one hour of our simulation. When wind generation is high, hydroelectric generation ramps down. When wind speeds drop, hydroelectric generation ramps up to compensate. This relationship is captured with a linear, best-fit line for each scenario. The line is higher for the scenario that includes Site C because there is an additional 1100 MW of hydroelectric capacity and an additional 1593 MW of wind capacity. Both lines show the strong negative correlation between output from wind and hydroelectric generation sources.

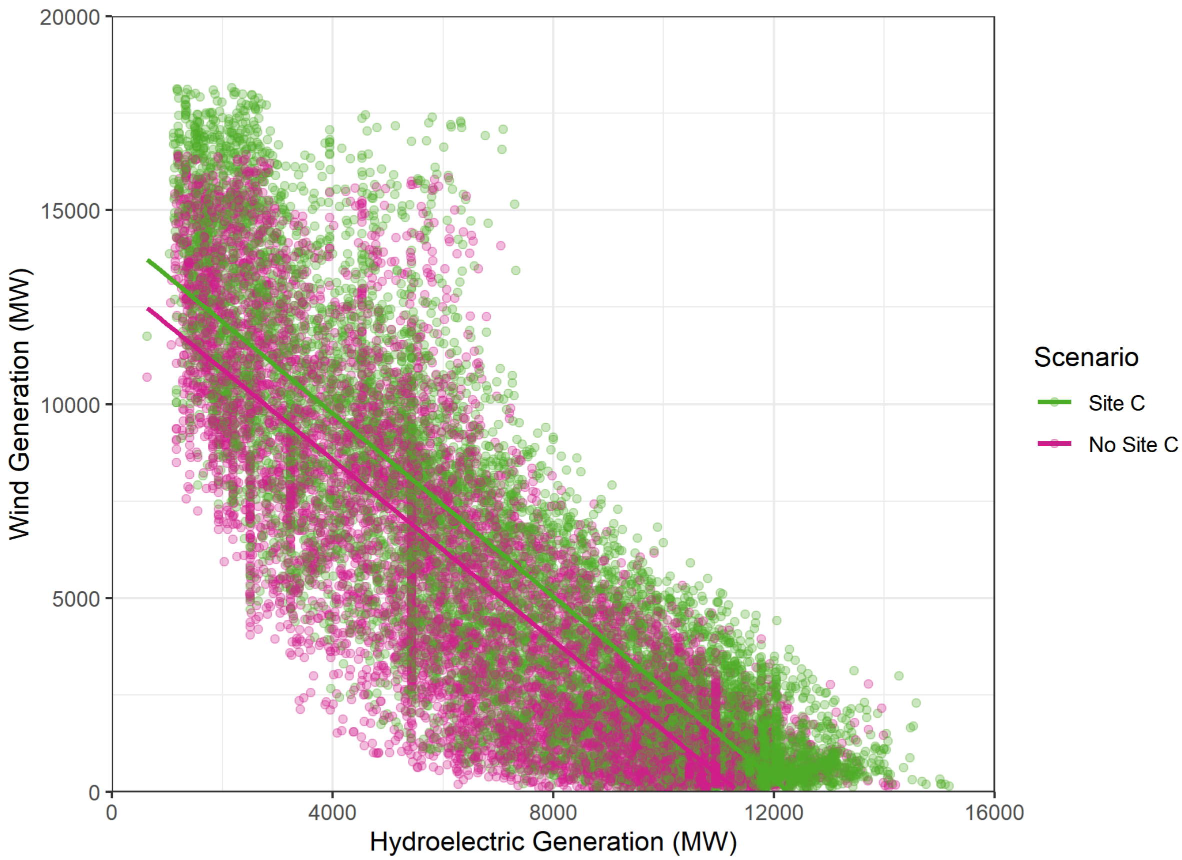

Figure 12: Wind and Hydroelectricity Generation Relationship.

Results are shown for the 100% decarbonization scenarios that include new AB-BC transmission.

Figure 13 shows hourly wind and hydroelectric output in January for a scenario that achieves 100% decarbonization and includes new AB-BC transmission links. The value of adding additional hydroelectric capacity is clear, as the dispatchability of hydroelectric facilities allows further low-cost wind generation, while ensuring demand can be met in each hour. What is also clear is this value does not exceed the cost of Site C in most scenarios.

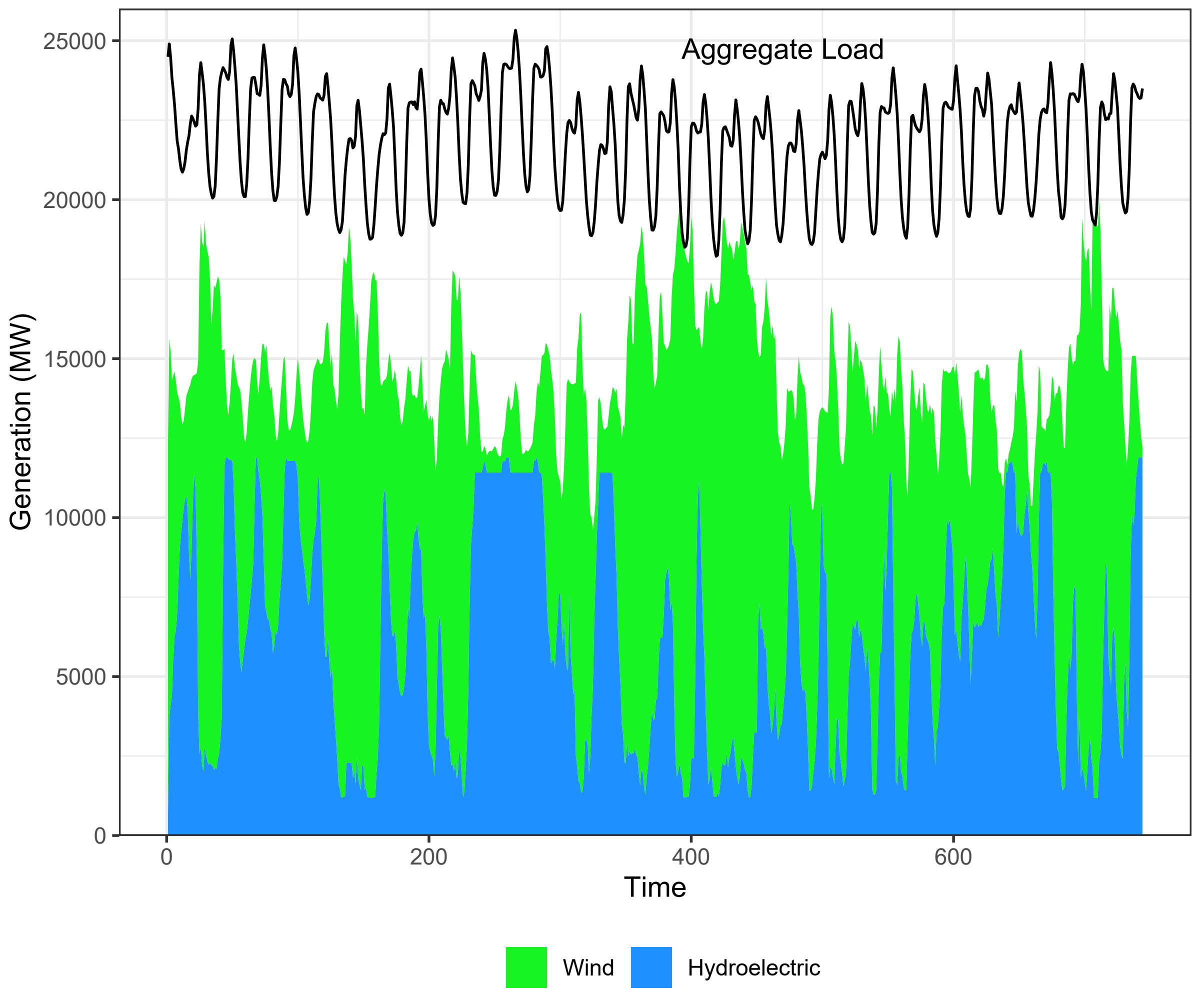

Figure 13: Hourly Wind and Hydroelectricity Generation in January for a Simulated 100% decarbonization scenario

Aggregate hourly load is shown as the black line at the top of the graph. The gap between demand and the combined output of wind and hydroelectricity is filled largely with additional output from nuclear power facilities in this scenario.

5 Conclusions

The Site C hydroelectric facility offsets the need for alternative generation capacity, allows increased integration of wind energy in scenarios with high decarbonization ambition, and provides a flexible, zero-emissions generation source. Using our model, we calculate the annual financial savings that results from providing these services. We find that the net present value of the savings created by Site C does not exceed Site C's current cost estimate of $16 billion, except in our sensitivity analysis scenario with high cost nuclear, 100% decarbonization of the Alberta and BC electricity systems, and new transmission built between the two provinces. The value of the savings created by Site C only exceeds its avoidable cost of approximately $5.8 billion (2021 $CAD) in scenarios with high emissions reduction ambition, and high inter-provincial coordination that allows for new AB-BC transmission connections and enhanced electricity trade. If any of these conditions are not met, then Site C is not economic and should not be completed.

We can speculate as to whether these conditions will be met. There is pressure to ratchet up GHG emissions reduction effort. Greater GHG emissions reduction effort will increase the value of the savings created by Site C. There are, however, barriers to inter-provincial coordination of electricity markets. BC Hydro is a government-owned utility, while Alberta features a competitive electricity market and an independent system operator. The administrative frictions between these two systems may lead to sub-optimal coordination, lowering the realized value of the Site C project.

As a caveat, our analysis is restricted to the system wide cost effectiveness of Site C and should not be considered a complete account of the costs and benefits of the Site C project. For example, we do not attempt to monetize the impact of the Site C project on the First Nations and landowners impacted by the project. A complete cost benefit analysis would consider the impacts of the Site C project on the the well-being of First Nations whose cultural sites and traditional lands are impacted, and local landowners unwillingly displaced by the project. Our focus lies only on the operational and capital costs of generating electricity in British Columbia and Alberta. Including additional costs would further decrease the net present value and economic viability of the Site C project.

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A Cost Assumptions

Table 1: Levelized Cost Assumptions and Model Cost Inputs ($2019 CAD)

Technology	Annualized Capital ($/MW)	Fixed O&M ($/MW)	Variable O&M ($/MWh)	Efficiency (%)	Capacity factor (%)	Facility life	Fuel Cost ($/GJ)	Emissions Intensity (tonnes/GJ)	Source
Natural gas simple cycle	88812	17416	7.30	0.404	0.100	20	3.60	0.0510	Lazard, 2019
Nuclear	751686	160223	5.14	0.344	0.905	40	1.19	0.0000	Lazard, 2019
Coal	364036	81273	5.14	0.347	0.745	40	1.11	0.0970	Lazard, 2019
Natural gas combined cycle	107651	16255	4.48	0.552	0.625	20	3.60	0.0510	Lazard, 2019
Coal with CCS	491941	108474	6.63	0.300	0.660	40	1.11	0.0097	Lazard, 2019
Diesel	72961	13836	13.84	0.369	0.525	20	25.87	0.0720	Lazard, 2019
Waste	390761	166818	6.41	0.271	0.625	20	0.00	0.0000	EIA, 2020
Natural gas cogeneration	107651	16255	4.48	0.552	0.625	20	0.00	0.0235	Lazard, 2019
Natural gas combined cycle with CCS	267081	36622	7.75	0.505	0.625	20	3.60	0.0051	EIA, 2020
Solar photovoltaic	87600	13932	0.00	NA	0.140	30	NA	0.0000	Lazard, 2019
Wind	139946	42793	0.00	NA	0.465	20	NA	0.0000	Lazard, 2019
Site C	769370	39621	0.00	NA	0.530	70	NA	0.0000	BC Hydro

B Additional figures

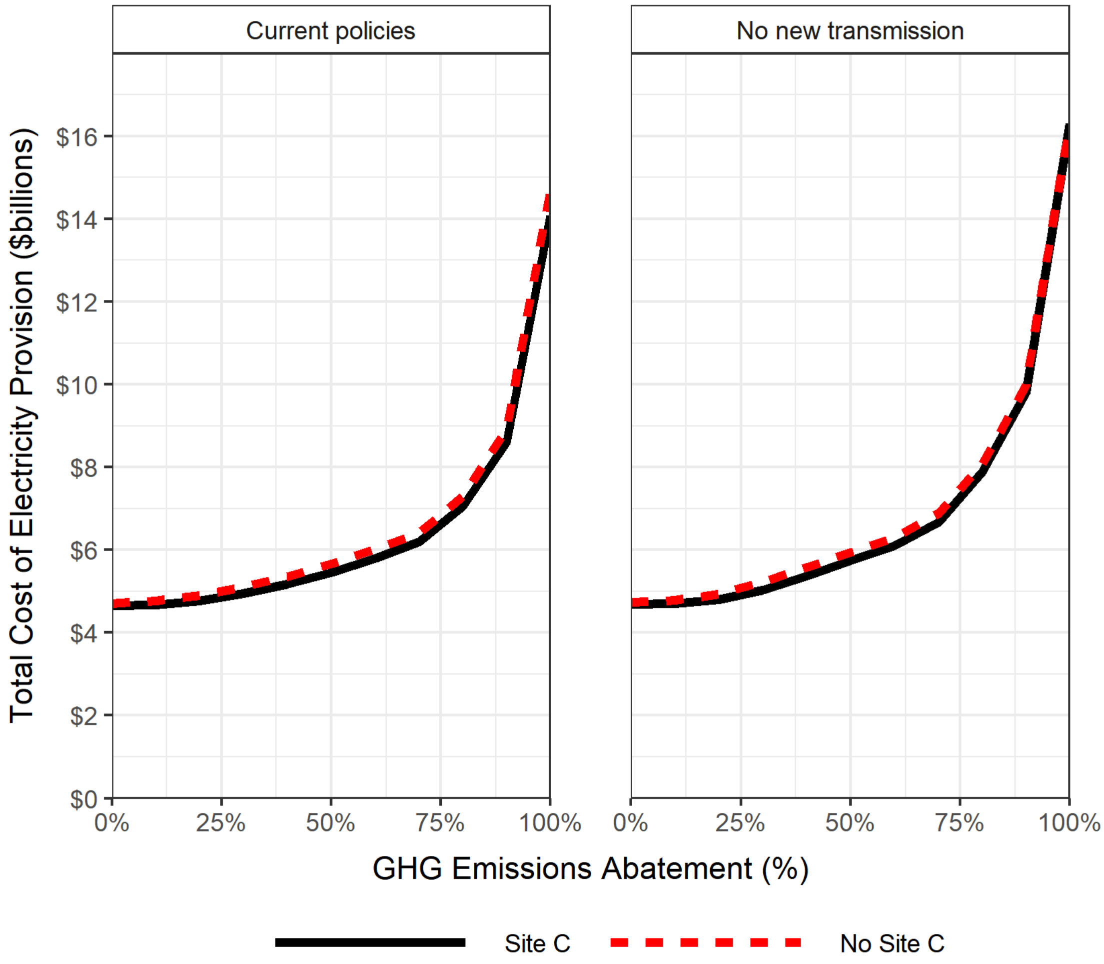


Figure 14: Total Annual Electricity System Cost

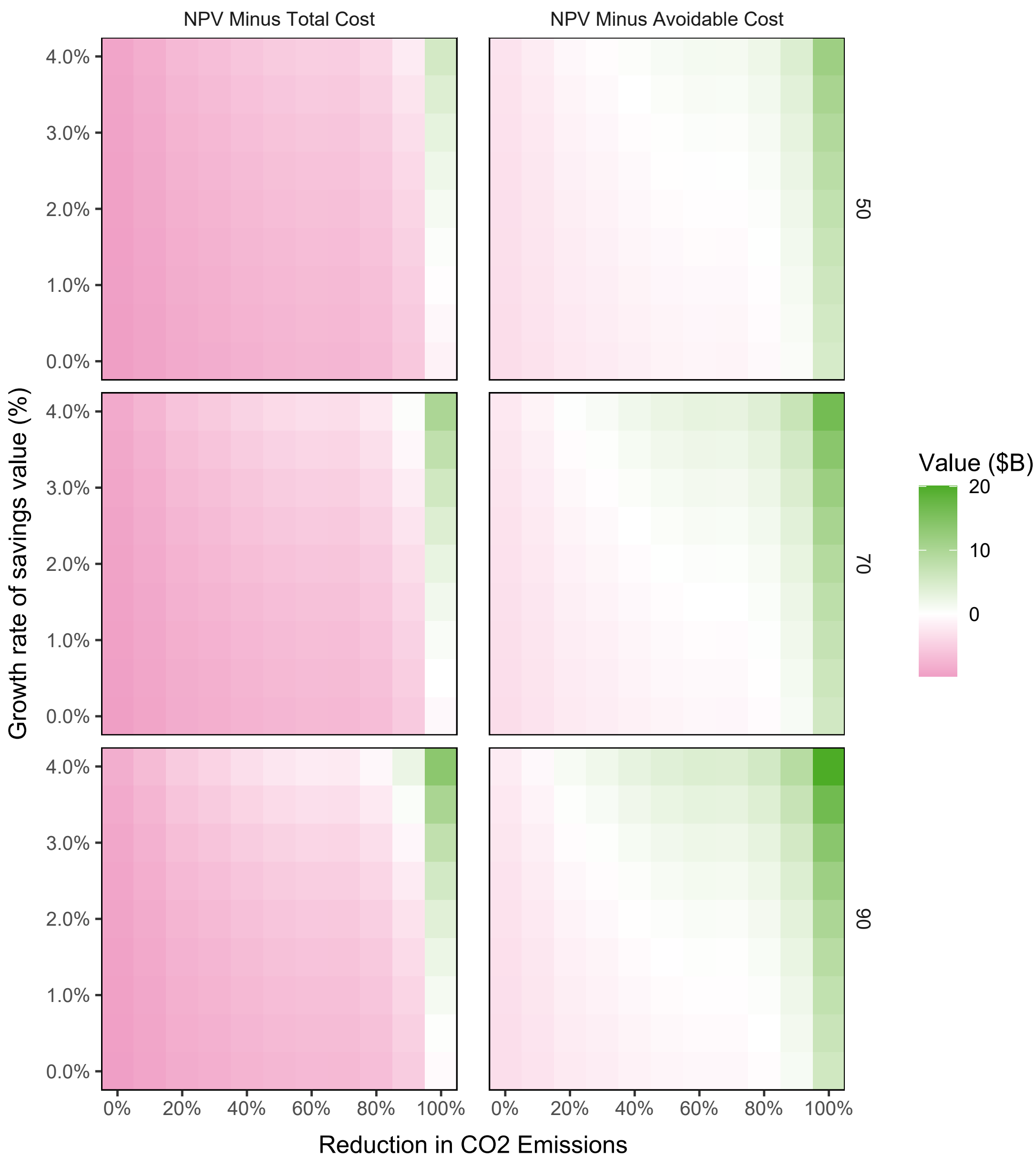


Figure 15: Net Present Value of Site C Sensitivity to Growth of Savings Rate and Facility Life Assumptions.

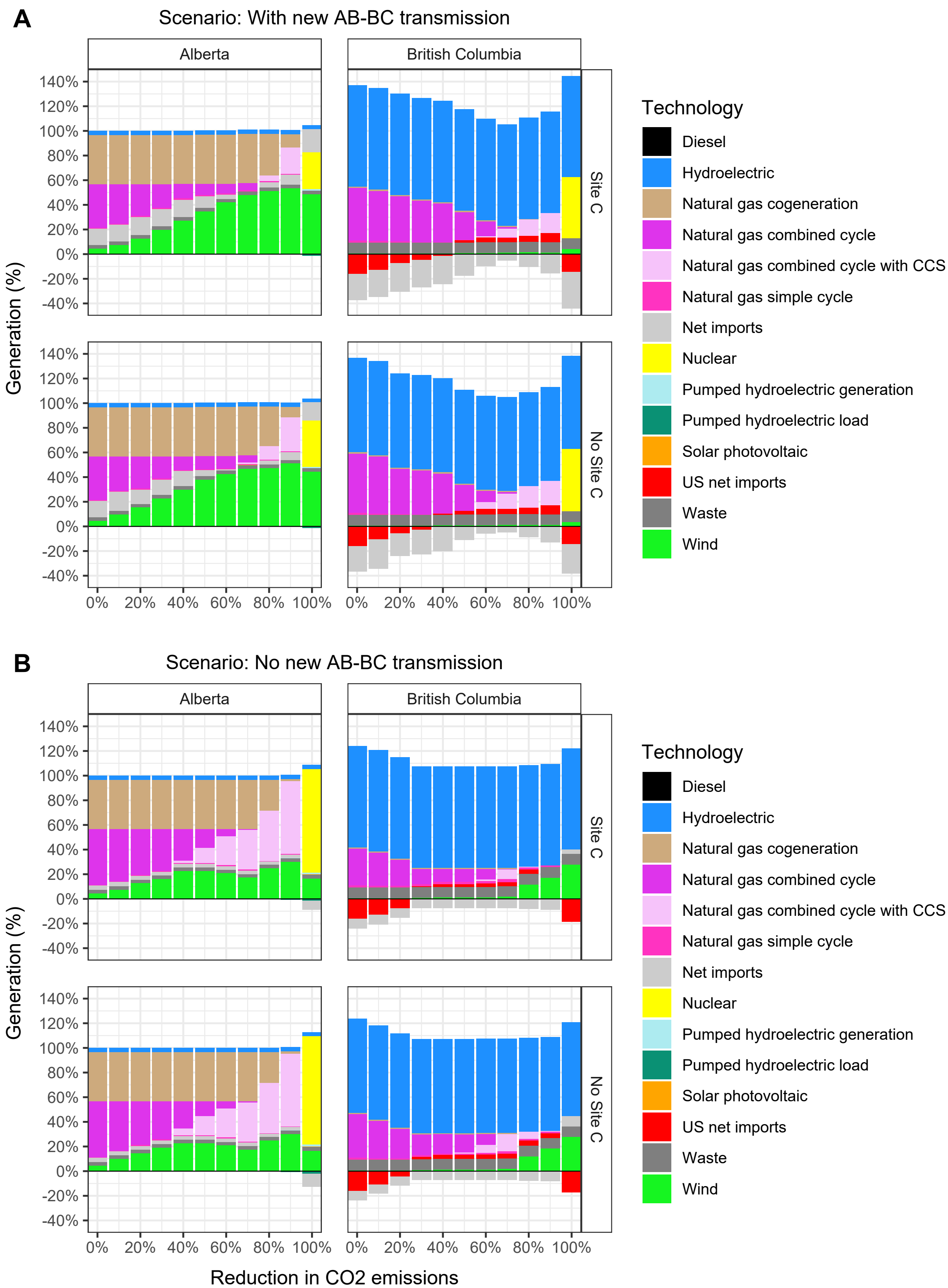


Figure 16: Electricity Generation Mix by Province and Scenario.

Panel A: New AB-BC transmission allowed. **Panel B**: No new AB-BC transmission allowed.

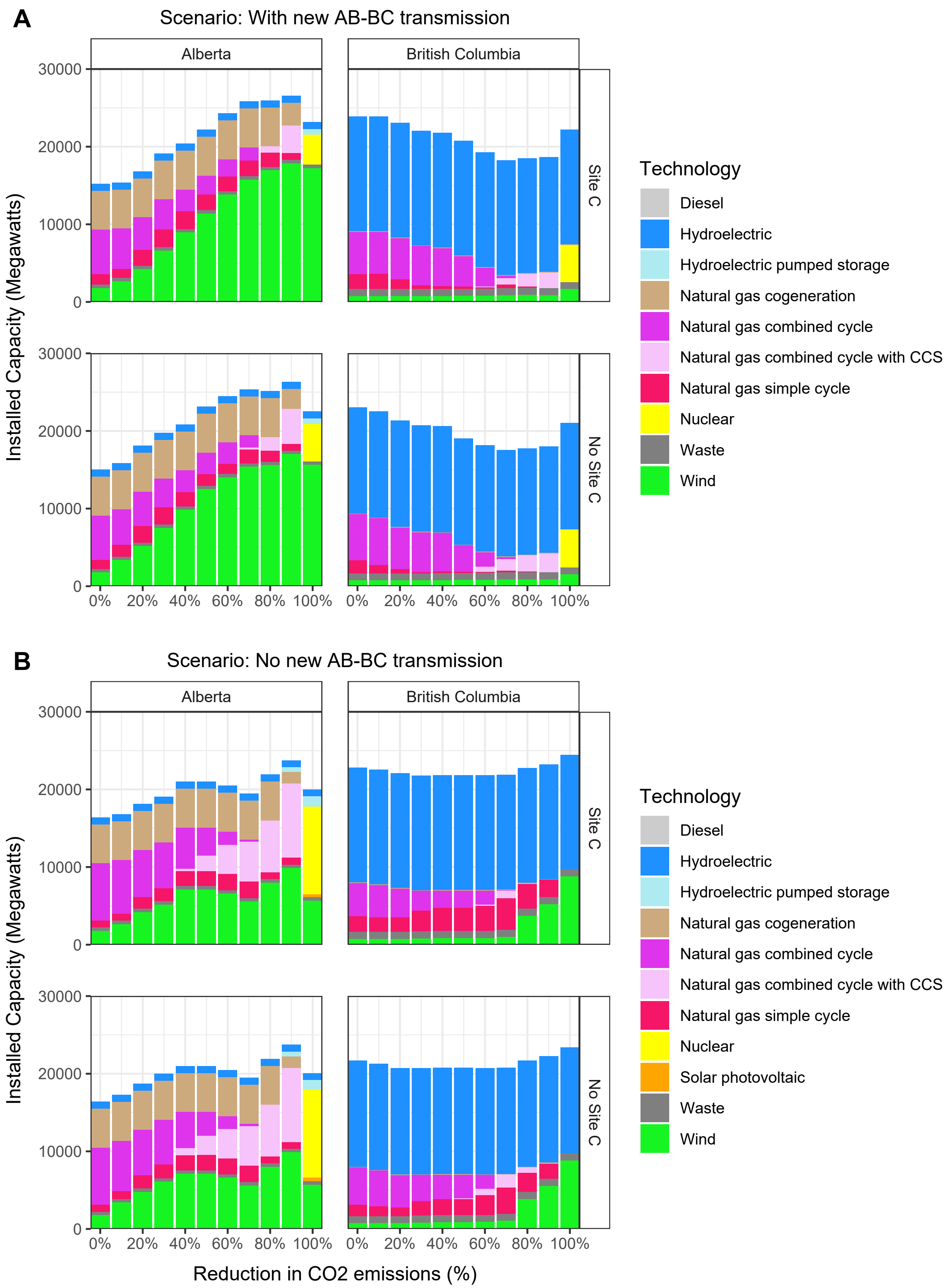


Figure 17: Electricity Capacity (MW) by Scenario.

Panel A: New AB-BC transmission allowed. **Panel B**: No new AB-BC transmission allowed.

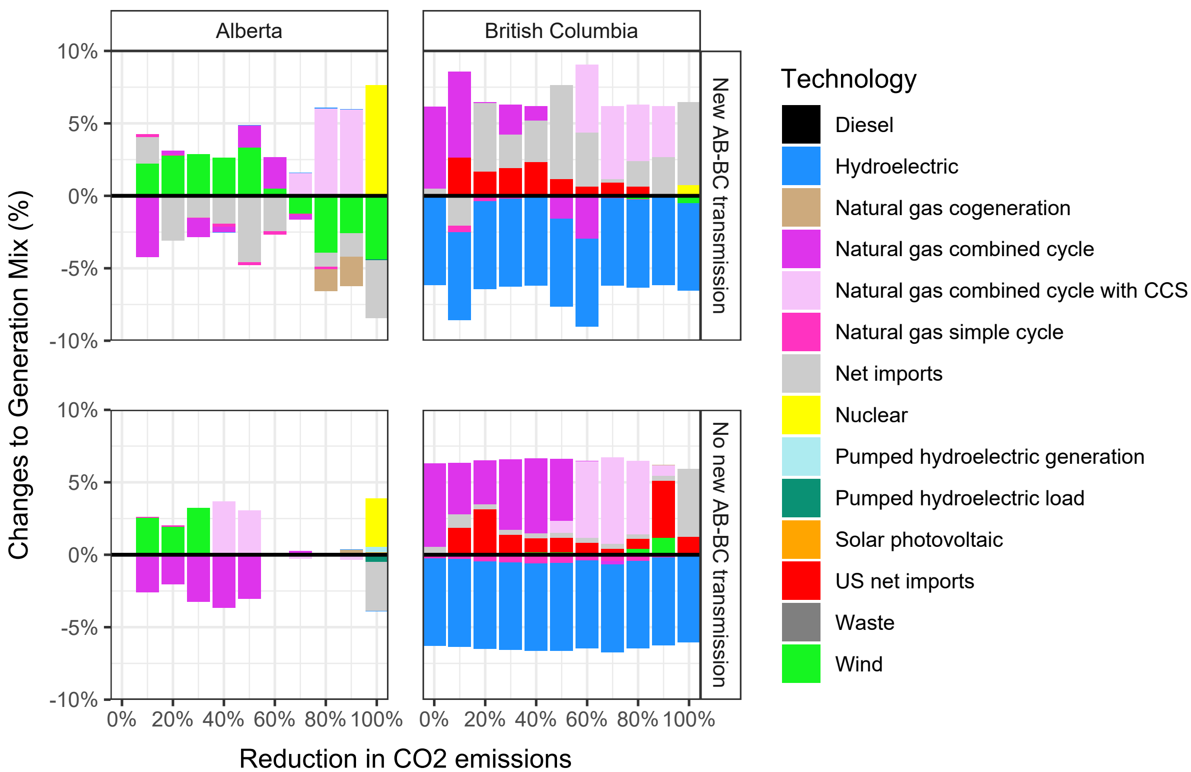


Figure 18: Changes to Electricity Generation Mix When Site C Is Not Constructed

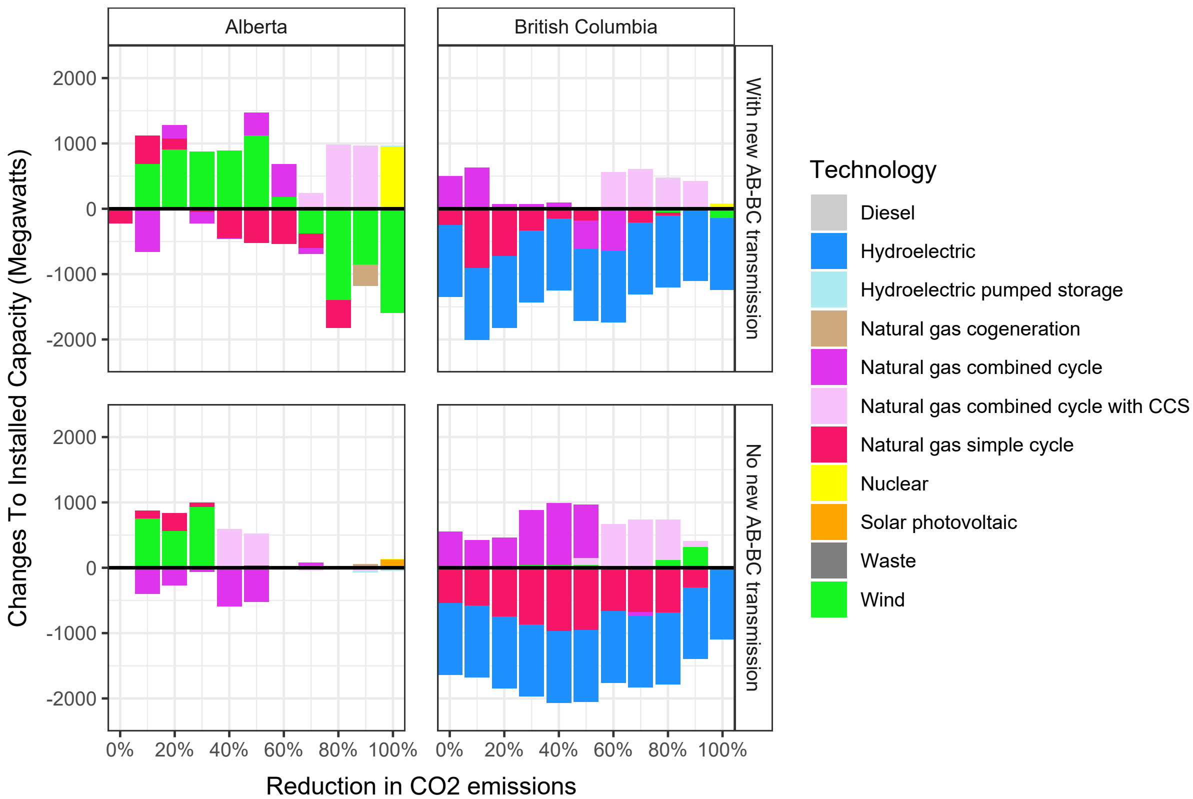


Figure 19: Changes to Electricity Capacity When Site C Is Not Constructed

C Concordance between AESO Planning Areas and Statistics Canada Economic Regions

Economic Region	AESO Planning Area
4810	4, 47, 52, 53, 54, 55
4820	13, 32, 36, 37, 42, 43, 45, 48, 49, 56
4830	6, 39, 46, 57
4840	29, 34, 38, 44
4850	35
4860	30, 31, 33, 40, 60
4870	17, 18, 19 20, 21, 22, 23, 24, 26
4880	25, 27, 28

D Calibrating Parameters Governing International Trade Flows

D.1 A Theory of Calibration for the Trade Flow Function parameters

Antweiler (2016) develops a model of two-way cross border trade in electricity based on "reciprocal load smoothing" between jurisdictions. This model directly informs our calibration approach.

From Antweiler (2016) consider an export profit function for a region of the form: $\pi^X = PX - [c_1 + c_2(Q + X/2)]X - \delta\tau X/2 \geq 0$ where X is the trade-flow; P is the equilibrium trade-flow price; Q is the region's internal load; c_1 and c_2 are cost function parameters, τ is a scalar representing trade costs and $\delta = 1$ when a region is exporting and $\delta = -1$ when importing.[16] From this profit function it is evident that the incentive compatibility condition for a region engaging in trade is:

$$\delta P > \delta\left(c_1 + c_2 Q + \frac{\tau}{2}\right) \begin{array}{ll} \delta = \ \ 1 & \Longrightarrow \text{Exporting} \\ \delta = -1 & \Longrightarrow \text{Importing} \end{array} \tag{4}$$

Rearranging and restating the equilibrium trade price and trade quantity (flow)

[16] This is equation (4) Antweiler (2016). Time period subscripts are omitted here as Antweiler (2016) develops this portion of the model for a single time period only.

conditions from Antweiler (2016) (equations 8 and 9):

$$P = \frac{\left(c_1^H + c_2^H Q^H\right)c_2^F + \left(c_1^F + c_2^F Q^F\right)c_2^H + \frac{\tau}{2}\left|c_2^H - c_2^H\right|}{c_2^H + c_2^F} \tag{5}$$

$$X^H = \frac{\left(c_1^F + c_2^F Q^F\right) - \left(c_1^H + c_2^H Q^H\right) - \delta\tau}{c_2^H + c_2^F} \tag{6}$$

where superscript H implies a cost function parameter for the home region and F implies a parameter for the foreign region, τ is a trade (or transmission) cost parameter and delta is a binary parameter where $X > 0 \implies \delta = 1$ and $X < 0 \implies \delta = -1$. Rearranging 6:

$$\left(c_1^H + c_2^H Q^H\right) = \left(c_1^F + c_2^F Q^F\right) - \left(c_2^H + c_2^F\right)X^H - \delta\tau \tag{7}$$

Substituting (7) into (5) and simplifying:

$$P = \left(c_1^F + c_2^F Q^F\right) - c_2^F X - \left[\tau \frac{\delta c_2^F - \frac{1}{2}\left|c_2^F - c_2^H\right|}{c_2^H + c_2^F}\right] \tag{8}$$

The home jurisdiction's received or paid price is then:

$$P - \frac{\delta g}{2} = \left(c_1^F + c_2^F Q^F\right) - c_2^F X - \left[\tau\left(\frac{\delta c_2^F - \frac{1}{2}\left|c_2^F - c_2^H\right|}{c_2^H + c_2^F} - \frac{\delta}{2}\right)\right] \tag{9}$$

In order to maintain consistency within the Linear Program, the price cannot be a function of any of the home jurisdiction's cost parameters. Given this, we assume that the right most term (in square brackets) is sufficiently close to zero such that we can ignore it.[17]

$$P = \left(c_1^F + c_2^F Q^F\right) - c_2^F X \tag{10}$$

We convert equation (10) into a step function where the unit cost of import or exports is fixed for a set of bins with a predefined width of k (in this case, 500 MW). We then assign a constant unit cost $v_{j,h}$ for import or export flows (realized or not)

[17]The bracketed term is near zero as long as τ is not too large and c_2^f is sufficiently close to c_2^h. Given the analysis in Antweiler (2016) combined with the observation that there is significant variation in both the size and the direction of flows on the British Columbia to U.S. inter-tie, this combination of assumptions seems reasonable. If g were large, there would be prolonged periods of net zero flows (which we do not observe) and if $\left|c_2^f - c_2^h\right|$ were large we would see unidirectional flows. Figure 5 in Antweiler (2016) is particularly useful in understanding these relationships.

in hour h and with magnitude corresponding to a fixed interval (or "bin") defined by $j \in \{-2500\,(500)\,3000\}$ where the upper and lower bounds are defined by the directional capacity of the intertie. Formally:

$$v_{j,h} = \left(c_1^F + c_2^F Q_t^F\right) - c_2^F \left(j \times k + sign\,(j) \times \frac{k}{2}\right) \tag{11}$$

D.2 Calibration

The model is calibrated using a combination of available 2018 and 2019 data collected through the NRGSTREAM Service. We observe hourly inter-tie flows between jurisdictions as well as total internal load for the home jurisdiction (B.C.) and the foreign jurisdiction (Puget Sound) for 2018 and 2019. We also observe the price attributed to these inter-tie flows for every hour of 2019. Unfortunately pricing data is not available for every hour in 2018.

Given the nature of intermittent renewable generation in both the home and foreign jurisdictions, we should not expect a static quadratic cost function to imply an accurate representation of marginal costs in each hour of the model calibration. In effect, the cost functions will change intra-day (given fluctuations in wind and solar) and inter-season (given fluctuations in hydro potential). To account for this, we develop a calibration process that allows for hour to hour changes in both the home and foreign cost function parameters.

The calibration exercise takes the form of a linear program using a set of constraints for the home and foreign jurisdictions based on the inequality constraints defined in equation (4) and an equality constraint defined by equation (6) with an added error term. The addition of this error term is necessary to ensure that the calibration is feasible. The objective function of the Linear Program is the minimization of the sum of the absolute values of the hourly differences in marginal cost parameters plus the error term added to equation (6). Formally:

$$
\begin{aligned}
&\underset{c^F_{1,h},\, c^F_{2,h},\, c^H_{1,h},\, c^H_{2,h},\, \tau}{\arg\min} \quad \sum_t \left(e_h + \mu^F_{1,h} + \mu^F_{2,h} + \mu^H_{1,h} + \mu^H_{2,h}\right) \\
&S.T. \quad \left.\begin{aligned} &\delta_h P_h \geq \delta_h \left(c^H_{1,h} + c^H_{2,h} Q^H_h + \frac{\tau}{2}\right) \\ &\delta_h P_h \leq \delta_h \left(c^F_{1,h} + c^F_{2,h} Q^F_t + \frac{\tau}{2}\right) \end{aligned}\right\} \text{Incentive Compatibility} \\
&\left.\begin{aligned} &e_h \geq \quad \left(X_h\left(c^H_{1,h} + c^F_{2,h}\right) - \left[\left(c^F_{1,h} + c^H_{2,h} Q^F_t\right) - \left(c^H_{1,h} + c^H_{2,h} Q^H_h\right)\right] - \delta_h \tau\right) \\ &e_h \geq - \left(X_h\left(c^H_{1,h} + c^F_{2,h}\right) - \left[\left(c^F_{1,h} + c^H_{2,h} Q^F_h\right) - \left(c^H_{1,h} + c^H_{2,h} Q^H_h\right)\right] - \delta_t \tau\right) \end{aligned}\right\} \text{Flow Equation Error} \\
&\left.\begin{aligned} &\mu^F_{1,h} \geq c^F_{1,h+1} - c^F_{1,h} && \mu^F_{2,h} \geq c^F_{2,h+1} - c^F_{2,h} \\ &\mu^F_{1,h} \geq c^F_{1,h} - c^F_{1,h+1} && \mu^F_{2,h} \geq c^F_{2,h} - c^F_{2,h+1} \end{aligned}\right\} \text{Foreign Cost Function Parametric Drift} \\
&\left.\begin{aligned} &\mu^H_{1,h} \geq c^H_{1,h+1} - c^H_{1,h} && \mu^H_{2,h} \geq c^H_{2,h+1} - c^H_{2,h} \\ &\mu^H_{1,h} \geq c^H_{1,h} - c^H_{1,h+1} && \mu^H_{2,h} \geq c^H_{2,h} - c^H_{2,h+1} \end{aligned}\right\} \text{Home Cost Function Parametric Drift}
\end{aligned}
\tag{12}
$$

The calibration is run using observable data (P_h, X_h, Q^H_h, Q^F_h, δ_h) from 2019. Hourly calibrated values for $c^F_{1,h+1}$ and $c^F_{2,h+1}$ are then paired with observable 2018 data (Q^F_h) in order to calibrate the values for $v_{j,h}$ as defined by equation (11). The result is, in effect, a set of hourly stepped import-demand/export-supply functions for international electricity flows on the British Columbia to U.S. inter-tie.

D.3 Calibration Goodness of Fit and Additional Adjustment

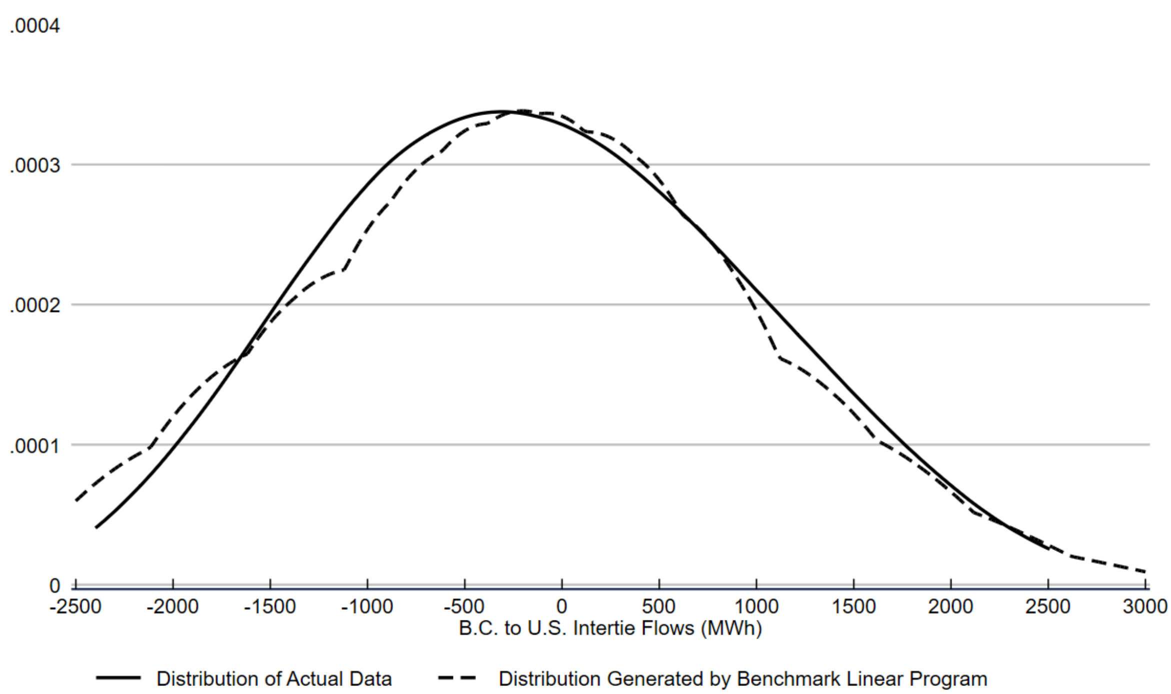
Modifying the Linear Program developed by Dolter and Rivers (2018) as described and solving it for a business as usual baseline generates modeled flows that generally approximate the actual recorded flows visible in the data.

Initial calibration using only those values fit via the Linear Program defined in (12) produced a distribution of hourly flows that closely match the second and third moments of the actual observable distribution. However the first moment was not a close match (i.e. the simulated flows had a lower mean).[18] This is expected given the nature of the optimization in our LP. As indicated above the LP optimizes the system from an annual perspective rather than optimizing on individual hours. Put another way the linear program optimization takes into account both the marginal costs of

[18]It is worth noting that this implies the fitted values for $c^F_{2,h}$, are a reasonable fit. This is important since these parameters govern how the calibrated step function values react to both changes in trade flows and changes in the foreign jurisdiction's internal load. Put another way, both the slope of the import-demand/export-supply function and the variation in it's intercept are good fit for the data based only on the parameter values identified by the LP defined by (12). It is the initial level of the intercept of that function which requires ad-hoc adjustment.

generation (hourly) and the annual ammortized values for the fixed costs of generation and transmission. Because of this, using only the hourly marginal costs/benefits of intertie flows under-represents these values relative to other supply sources in the model. The marginal values do accurately represent hour to hour variations in the demand/supply and quantity-demanded/quantity-supplied of intertie flows, which is why the initial calibration produces a distribution of intertie flows that reasonably matches the second and third moments of observed distribution. To address this, we introduce an ad-hoc modification to the level of the calibrated values for $v_{j,h}$. Specifically, we add a fixed value to the right hand side of equation (11) to account for unobservable annualized fixed costs and to produce a closer match between the first moment of the two flow distributions. Figure 20 shows the overlap between the observed and benchmark replication of the two distributions with this ad-hoc adjustment in place.

Figure 20: Distribution of Observed flows vs Distribution of LP Simulated Flows



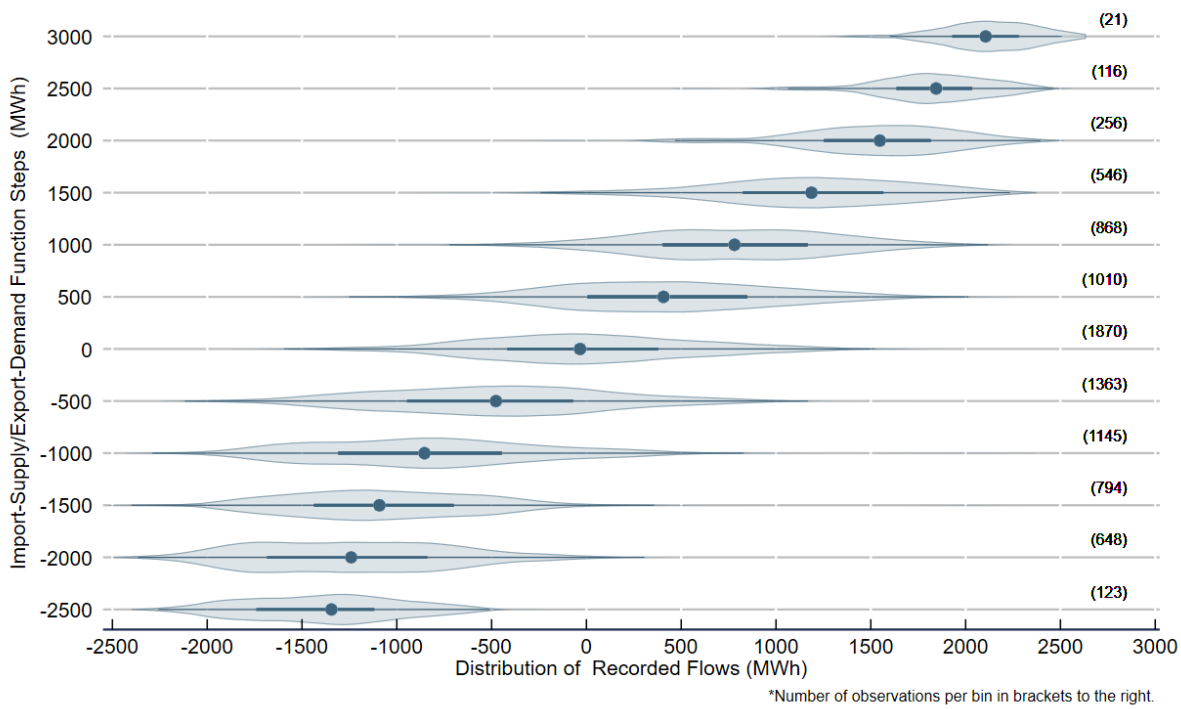
Summary statistics are provided in Table 2.

In addition to producing a similar distribution of flows, the calibration also produces simulated benchmark flows that are generally correlated with their observed counterparts in each area. This is illustrated using a set of violin plots in figure 21.

Table 2: Summary Statistics for LP generated Intertie flows and Actual Intertie flows

VARIABLES	(1) N	(2) mean	(3) sd	(4) max	(5) min
LP_Flow	8,760	-190.2	1,063	3,000	-2,500
Actual_Flow	8,760	-123.6	987.1	2,508	-2,399

Figure 21: Correlation between Observed and LP Simulated Flows by Bin



Given this, we are reasonably confident that our calibration exercise represents a realistic approach to dealing with endogenous international trade flows within our linear programming model.