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Flexibility requirements and electricity system planning: Assessing inter-regional coordination with large penetrations of variable renewable supplies

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ABSTRACT

Decarbonizing electricity generation through deployment of renewable technologies such as wind and solar is a key component of many climate change mitigation efforts. With increasing penetrations, the need to manage variability in renewable generation becomes critical. However, renewable variability is often poorly represented in energy planning studies which focus on energy and capacity adequacy. In this study, we used a hybrid capacity expansion and dispatch model with explicit inclusion of ramping and regulation services to examine balancing requirements in a decarbonizing electricity system. We find that ramping and regulation services needed for management of variable renewables alter the optimal mix of generation and transmission capacity relative to simpler planning models. In particular, we find enhanced value in expanding transmission capacity to access flexibility.

1. Introduction

The transition from emissions-intense sources of electricity to renewables, and the substitution of fossil fuels with clean electricity are key components of many climate change policies. However, renewable resources like wind and solar, and new electrical loads such as electric vehicles, can be highly variable and uncertain. As their penetration increases, so, too, does the need for flexibility in the electrical system [1]. With constraints on the type of generators that can be used in a fleet, providing the flexibility to manage variability can increase the total cost of electricity [2]. Because flexibility is typically related to short-term operational requirements, it is a challenging issue to include in long-term capacity expansion and dispatch studies. Thus, with increasing emphasis on the use of variable renewable supplies, there is a growing need for planning studies that capture effects of variability and the impact on adequacy and reliability. More broadly, quantifying system costs of net load variability is needed to inform policies aimed at decarbonizing electrical systems.

Previous studies have examined the effect of increasing levels of capacity from variable renewable (VR) generators on the variability of net load (*i.e.* load that must be met by conventional generators). Olausen et al. [3] examined the change in net load variability in the Nordic power system with increasing amounts of VR energy. It was found that replacing thermal and nuclear generation with VR energy increased the standard deviation of net load, particularly in the medium-term (2 days–4 months) and that the peak net load and hourly ramp rates rise as well [3]. In a study of California, it was determined that high levels of VR generation require additional ramping from dispatchable generation and that the VR capacity required to reach high energy penetrations results in times of surplus supply, lowering the value of VR energy [4]. These effects can be mitigated, to some degree, by deploying a complementary mix of wind and solar generation to reduce the frequency and duration of concurrent generation events [5], by dispatching hydroelectric generators in times of low-VR production [6].

Energy storage has been evaluated as a means to increase the grid's ability to manage the variability in net load. Recent studies have found that a near-fully renewable powered electricity system is feasible with very high VR penetrations provided that large storage capacities are available [7–9]. Storage has also been shown

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to increase the value of VR energy; however, due to the high cost of storage technologies, widespread grid-level energy storage is currently uneconomical [10–12].

Interregional transmission can provide access to capacity and flexibility and allow high penetrations of VR energy at lower cost than in isolated systems. A one-year study in Northeast Asia found that both the cost and emissions of electricity generation are reduced by increasing transmission between regions [13]. In a study of the European electricity system, Rodriguez et al. found that the portion of annual energy that must be served by balancing generators is reduced when interregional transmission is increased [14]. Other studies have found that increased transmission can reduce curtailment in high penetration VR scenarios [11,15,16], thereby increasing the portion of system energy served by VR, and reducing the cost of meeting renewable energy targets [17].

Fully renewable electricity systems with increased interregional transmission have been studied for Europe [8] and the Nordic power system [3]. In the latter study, net load variability can be met by existing hydroelectric facilities with no need for new storage capacity. Both of these studies consider systems with defined VR mixes optimized to reduce VR production variability over a period of one year. These studies do not present a least cost VR mix, nor do they examine the transition from today's electricity system to one that is fully renewable.

Interregional transmission can provide access to energy and ancillary services. To realize these technical benefits, there must also be appropriate coordination of regional assets. Understanding how technical benefits couple with markets and regulatory frameworks are important issues in the transition of electrical systems to high penetrations of VR. In particular, the assessment of long-term system structures which include short term demands such as regulation and ramping capacity is needed. In this study, we examine the impact of flexibility requirements on interregional transmission and generation fleets in a two-region electricity system with high penetrations of VR generation. These regions are jointly optimized using a long-term hybrid expansion and dispatch model. This work builds on a previous study by including short-term flexibility constraints in a long-term electricity system optimization [18]. Expanding on this previous study, we explore the impacts of these flexibility requirements on the expansion and dispatch of the electrical system and the value of interregional transmission in an optimized low-carbon system. This study contributes to the literature by implementing constraints caused by short-term phenomena, namely variable renewable energy output, in a long-term capacity expansion model including potential offsetting resources, particularly hydroelectric generation and interregional transmission.

In the following sections we first describe the modelling methodology, followed by the results showing capacity and dispatch to year 2060, and finally the implication of these results for regional coordination through service sharing.

2. Methods

Designing electrical systems for the future often relies on cost minimized capacity expansion and dispatch models [19]. The issue of increasing need for flexibility due to variability in supply and demand has spurred new methods for system planning [20]. In this study, a long-term model is used that directly accounts for the variability of net load in the expansion and operation of the electricity system. We focus specifically on the impacts of net-load variability due to large-scale penetrations of VR. Two balancing regions are modeled connected by a single expandable intertie. The growth in intertie capacity and the use of the transmission lines is determined endogenously.

The model minimizes cost to deliver four specific services: baseload energy, peaking, ramping, and regulation capacity as described in Section 2.1. Flexibility requirements due to load and VR are defined. Section 2.2 describes the different generation technologies, their respective ability to provide each service type of service, and their capital, fixed and variable costs. Costs incurred by dispatchable generators due to ramping are explained. The study uses the western Canadian provinces of British Columbia (BC) and Alberta (AB) as a representative case of interconnected jurisdictions with very different attributes. One, (BC), is low-carbon and flexible due to the use of large reservoir hydro, and the other (AB) is a system dominated by fossil fuel with goals for decarbonisation. The regional characteristics are described in Section 2.3 along with policies defining carbon costs and renewable credits.

2.1. Capacity expansion and dispatch

Long-term capacity expansion and dispatch optimization from the year 2015–2060 is performed under technological, economic, and policy constraints. The optimization model is based on the Open Source Energy Modelling System (OSeMOSYS), an open source energy model previously described in Refs. [21,22]. The model is written using GNU MathProg and solved using the GNU linear programming kit (glpk). A key addition to OSeMOSYS functionality used in this study is explicit modelling of cascaded hydroelectric systems [18]. The model optimizes water use by generators on defined river systems with constraints on minimum and maximum flow rates and reservoir volumes. This level of detail is desirable for jurisdictions dominated by reservoir hydro as it allows the long-term storage potential of these reservoirs to be co-optimized with shorter term dispatch and expansion of non-hydroelectric generators.

In the past, including in energy dispatched by generators and the associated capacity required for peak days and reserve margin would be the key outputs of a planning study. Uncertainty and variability emphasize the need for dispatchability and responsiveness. Hence, in addition to energy dispatch and capacity, this work uses another extension that captures short-term constraints on the electrical system such as minimum generation level, maximum output changes between time steps (ramping), and capacity allocated to regulation. This OSeMOSYS extension is published in Ref. [23] with further validation in Ref. [20]. This allows flexibility commitment to be modelled explicitly. In the present study, we expand on this method by requiring additional flexibility to support VR generation; this is described in detail in the following sections.

2.1.1. Time steps

A model year is divided into 32 time steps where each time step represents a group of hours. A *day* is represented by four groups of hours: (1) night - from 9pm to 4am, (2) morning - from 4am to 9am, (3) mid-day - from 9am to 3pm, and (4) evening - from 3pm to 9pm. In addition, two types of days (*regular* and *high-load*) are defined for each of the four *seasons*: winter, spring, summer, and autumn. Regular and high-load days are defined by daily energy demand where high-load days represent the 13 highest demand days in a season (one per week) and regular-load days represent the remaining days in that season. Seasons and daily time periods are categorized chronologically to track storage use. Four seasons, with two day-types, and each day with four demand periods results in 32 time steps in a year. Annual load profiles and demand growth are exogenously defined based on regional projections from the system balancing authorities.

2.1.2. Services

Four services are defined that must be provided during every time step: *baseload, peaking, ramping* and *regulation*. Two services, *baseload* and *peaking*, are energy services. *Ramping* and *regulation* are flexibility services which ensure sufficient dispatchable generation to match short-term load fluctuations. Flexibility services meet changes in demand that occur on hourly (ramping) and sub-hourly (regulation) time scales. Flexibility requirements are assumed to be the same in high-load and regular days. For each time step, the optimization must meet the requirement for each of these four services in both BC and Alberta.

A sample daily profile with baseload and peaking services is shown in Fig. 1 where the black line shows the aggregated hourly demand in a region. The hourly baseload energy demand is approximated by the dark blue region where the plateaus correspond to the time-steps. The light blue regions represent the peaking energy requirements for each time step in excess of the baseload demand.

The peaking energy demand, E^{PK}, for each time step, i, is the difference between the average energy demand and the highest hourly demand for a time step as defined by Equation (1),

$$E_i^{PK} = \max_{1 \le h \le N_i} (\mathrm{L_{h,i}}) - \frac{\sum_h^N L_{h,i}}{N_i} \;\forall\; \mathrm{i} \in TS \tag{1}$$

where L represents hourly load in MW, N is the number of hours in a time step, subscript h represents time in hours, and TS is the set of unique time steps. In many other energy models, peak capacity requirements are represented by a reserve margin constraint that captures the capacity need, but not the energy component of this peak demand [22,24].

Baseload demand, E^{BL}, is the cumulative energy demand over a time step, less the peaking energy, as defined in Equation (2).

$$E_i^{BL} = \sum_h^{N_i} L_{h,i} - E_i^{PK} \;\forall\; \mathrm{i} \in TS \tag{2}$$

Ramping flexibility meets hourly changes in load as shown in Fig. 2. Requirements for ramping capacity, F^{RP}, for each time step are then determined by the largest one-hour change in load in each time step as defined by Equation (3).

$$F_i^{RP} = \max_{1 \le h \le N_i} ((L_{h,i}) - (L_{h-1,i})) \;\forall\; \mathrm{i} \in TS \tag{3}$$

Ramping requirements must be met by dispatchable generators.

Regulation requirements refer to short-term balancing - in this work, any changes in demand occurring at less than one hour. Regulation requirements are defined by historical regulating reserve dispatch in Alberta, typically set between 1% and 2% of load [25]. The regulation capacity, F^{RG}, for each time step is defined as the highest hourly dispatched reserve during that time step, as defined in Equation (4).

$$F_i^{RG} = \max_{1 \le h \le N_i} (\mathrm{DR_{h,i}}) \;\forall\; i \in TS \tag{4}$$

where DR is the dispatched regulating reserve (*i.e.* generation dedicated to meeting short-term load fluctuations) and N_i is the number of hours in the time step i. The regulation requirement for the sample day is shown in Fig. 3 where the dispatched regulation reserve (black line) is the actual value for the sample day. For future years, the regulation requirement for each time step is assumed to scale linearly with increase in demand (i.e. remaining at 1–2% of demand as for the initial year 2015.)

When generators providing a flexibility service (referred to in this paper as being *committed* to this service) are called upon to meet load changes they produce energy as the generator output ramps to follow demand. As a result, some of the flexibility committed generation capacity will produce energy during the time step. Historically, the average energy output of flexibility-committed generators is 18% of ramping-committed capacity and 47% of regulation-committed capacity, based on the 2015 load profiles of BC and Alberta [26,27].

This energy production from flexibility commitment is accounted for in the model and allocated to meeting the baseload

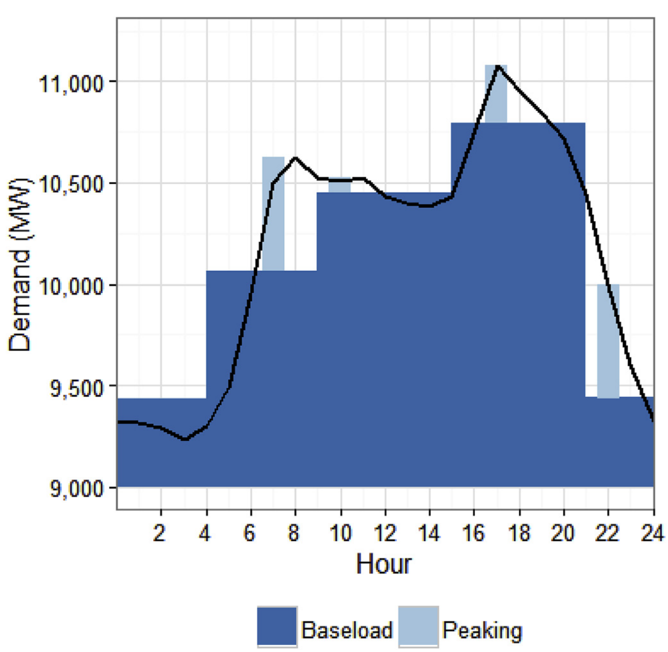

Fig. 1. Sample daily demand profile (solid line). The dark blue areas represent baseload in daily time-steps and light blue areas represent peaking demand within each time-step. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

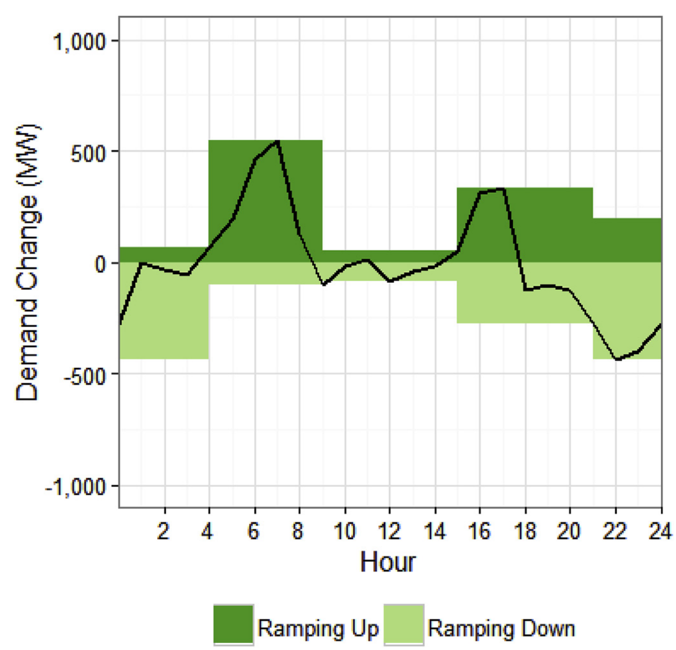

Fig. 2. Hourly changes in demand (black line). Positive changes reflect ramp up requirements while negative changes are ramp down demand. Ramping demands for each time step is determined by the maximum up and down requirements.

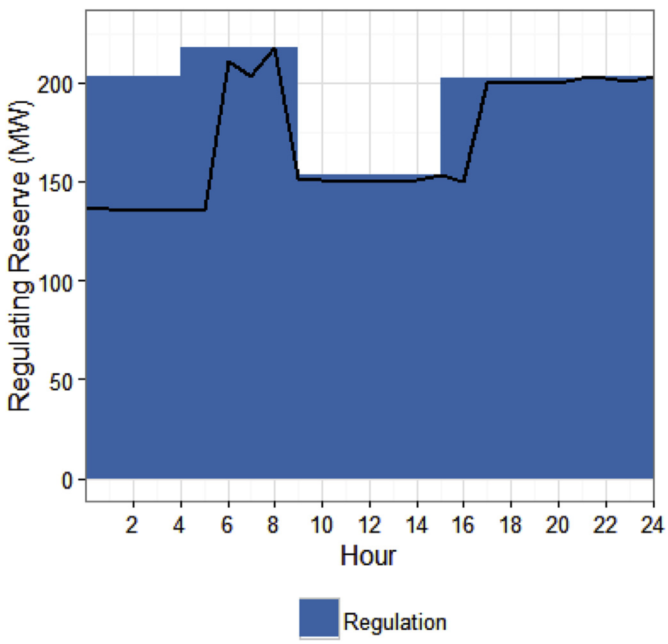

Fig. 3. Regulating reserve for a sample day (black line) and regulation demand for each time slice (dark blue areas.). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

energy demand in an associated time slice. The energy provided by flexibility-committed generators, E^{flex}, is determined by the energy content of hourly load changes as defined by Equation (5).

$$E^{flex} = \sum_{h=2}^{8760} \frac{(L_h - L_{h-1})(1\ hour)}{2} \tag{5}$$

The variability of wind and solar generation requires additional ramping and reserve flexibility above that required by load variability. A recent review examined a range of simulation and statistical studies of the flexibility requirements in high-VR systems [28]. This review found that estimates of flexibility requirements vary among regions, VR energy penetrations, and evaluation methods. Brouwer at al. estimate the required flexible capacity as a fraction of VR capacity, *f*, to be

$$F^{VR} = f \times G^{VR}. \tag{6}$$

where G^{VR} is the capacity of a VR resource and *f*, is 7% for ramping and 1% for regulation.

In this study, total ramping and regulation requirements provided by dispatchable generators are defined by a component related to demand variability, F^{load}, (as described previously in Section 2.1) and a component related to VR penetration. Here, the ramping and regulating capacity needed in each time step to support VR is determined by the average energy produced by VR. In this way, a resource such as solar, which is not generating during the night will not incur additional flexibility costs night time steps. The capacity scaling proposed by Brouwer can be related to energy production using the annual capacity factor, *CF*, of a resource, i.e.

$$E^{VR} = \mathrm{CF} \times G^{VR}. \tag{7}$$

where E^{VR} is annual energy production and CF is the annual capacity factor. Using Equation (7) in Equation (6), flexible capacity is a function of annual energy production and capacity factor,

$$F^{VR} = f/CF \times E^{VR}. \tag{8}$$

This relationship is assumed to hold for each time step where average annual energy production, E^{VR}, is replaced by the average production in a time step, P^{VR}.

Thus, the total capacity requirement for each type of flexibility, *F*, is due to load variations, F^{load}, (defined by Equations (3) and (4)) and average VR energy generation in a time step, *i*.

$$F_i^j = F_i^{j,load} + f_i^j \Big/ CF \times P_i^{VR}. \tag{9}$$

Equation (9) is used to define both ramping and regulation requirement in each time step (superscript *j* represents ramping or regulating). For this study, $f_{i,}$ for ramping and regulation requirements are assumed to be 7% and 1% of VR capacity, respectively, based on the results of [28]. Using these values and the capacity factors in Table 1 yields *f/CF* for ramping of 0.21 for wind and 0.42 for solar; and, for regulation, *f/CF* is 0.03 for wind and 0.06 for solar. The high value for solar is a result of its low annual capacity factor and the constant ratio of flexibility requirement to VR capacity. Each value F_i^j represents a constraint for the optimization model.

2.2. Generation characteristics

Each generation type is constrained in its ability to provide the four services. These constraints include: ramp rates, minimum generation, the ability of a generator to provide peaking service, and availability factor. For dispatchable generators, availability limits the total commitment across all four services in a year including the need to account for typical maintenance. Availability factor for VR supplies is equal to capacity factor. Highly flexible generators, such as natural gas fired units, are assumed to ramp up to 80% of their rated capacity in an hour while traditional baseload generators, such as coal, are assumed to ramp up to 20% of rated capacity. Maximum regulation commitment is constrained to 0.167 (*i.e.* 1/6) of the maximum ramping commitment consistent with the 10 min time frame of regulation used by many balancing authorities [25]. Table 1 summarizes the assumed limits of each generation technology.

2.2.1. Costs

Costs for all generators as well as coal and natural gas prices are taken from the US Energy Information Administration (EIA) 2015 Annual Energy Outlook [29] and presented in Table 2. The capital cost for an expanded BC-Alberta intertie is assumed to be $820/kW based on the cost of recent high-voltage transmission lines in the region [18].

Cost reductions over time are included for maturing technologies (*i.e.* CCS, wind, and solar). The model assumes that production from VR can be curtailed at no cost. Ramping operation and maintenance cost (Ramping O&M) is the cost to provide flexibility services and is defined as a function of the capacity committed to flexibility service. The capital, fixed O&M, variable O&M, and ramping O&M cost for each generator type are given in Table 2.

In addition to ramping O&M, generators committed for flexibility services incur costs on the energy produced. As a result, energy provided by ramping and regulating generators is more expensive than for the same generator providing baseload. The total variable O&M cost (excluding fuel cost), $C_s^{T\ O\&M}$, for each generator in each time step is given in Equation (10):

$$C_s^{T\ O\&M} = C_R^{O\&M} + \alpha_s^{VR} C_{BL}^{O\&M} \tag{10}$$

Where $C_R^{O\&M}$ is the ramping O&M cost, $C_{BL}^{O\&M}$ is the variable

Table 1
Limits on the production from each generator type. Annual availability factor is the maximum energy output over the year. Minimum generation is the minimum percentage of installed capacity that must be dispatched if a generator is being used in a time step. Maximum ramping and regulation commitments are the percentages of installed capacity that can be committed to providing ramping and regulation in a time step.

Technology	Annual Availability or Capacity Factor (%)	Minimum Generation (% capacity)	Maximum Ramping Commitment (% capacity)	Maximum Regulation Commitment (% capacity)	Maximum Peaking Commitment (% capacity)
Coal	85	70	20	3	100
Coal with CCS	85	70	20	3	100
SCGT	92	20	80	13	100
CCGT	87	50	80	13	100
CCGT with CCS	87	50	80	13	100
Storage hydro[a]	Varies	10	80	13	100
Hydro[b]	20/47	10/70	80/30	13/6	100
Wind[b]	33/27	0	0	0	0
Solar[b]	17/20	0	0	0	0
Geothermal	92	40	20	3	100
Biomass	83	70	20	3	100

[a] Storage hydro is treated differently than other generators.
[b] Values differ between provinces. The first value is for Alberta, the second for BC.

Table 2
Cost of different generator types. All costs are from the US EIA [29] except for ramping O&M which is from Ref. [30].

Technology	Capital Cost 2015 ($/kW)	Capital Cost 2050 ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (MJ/kWh)	Ramping O&M ($/MWh)
Coal	N/A	N/A	29.62	4.47	8,800	2.45
Coal with CCS	6102	5442	63.11	8.44	10,700	2.45
SCGT	631	631	6.69	10.37	10,800	1.59
CCGT	956	956	14.60	3.27	7,050	0.64
CCGT with CCS	1947	1713	30.20	6.44	7,530	0.64
Hydro	2492	2492	13.42	0	0	0.59
Storage hydro	N/A	N/A	13.42	0	0	0.59
Geothermal	2301	2301	95.00	0	0	3.34
Biomass	3540	3540	100.35	27.9	0	3.34
Solar	1541	1389	23.46	–	–	–
Wind	1861	1770	37.57	0	0	–

O&M cost for baseload production, and subscript s is the service provided (ramping or regulation). α_s^{VR} is the ratio of energy provided by a flexibility-committed generator to the capacity-hours committed; it is 0.18 for ramping and 0.47 for regulation.

2.3. Regional electrical systems

The model optimizes the capacity expansion and dispatch of the integrated BC-AB electricity systems and the intertie connecting them. The regional generation mixtures are initialized for year 2015 based on the existing generators and intertie capacity. A schematic representation of the model is given in Fig. 4 where the technology options for the BC and AB regions are on the left and right respectively. Besides the intertie connecting BC and AB there is also an intertie between BC and the neighboring US market known as MidC.

Two cascaded hydroelectric systems are modelled in the BC region: (1) the Peace River, containing the G.M. Shrum, Peace Canyon and, beginning in 2024, Site C generating stations[1]; and, (2) the upper Columbia River, containing the Mica and Revelstoke generating stations. The combined capacity of these generators is 3.46 GW for the Peace River, increasing to 4.56 GW with the addition of Site C, and 5.17 GW for the Columbia River. As of 2014, the Peace and Columbia systems together serve approximately 50% of the BC energy demand. This share varies from year to year depending on natural inflow, energy demand, and market conditions in neighbouring jurisdictions [31]. The remaining hydroelectric generators in BC, referred to as non-storage hydroelectricity, do not have significant seasonal storage capacity. These generators can provide a limited amount of flexibility but are otherwise non-dispatchable. Reservoirs for these generators are not explicitly modelled. Instead, their output is specified seasonally following historical output patterns in the same manner as used in Ref. [18].

The BC system is connected to the Mid-Columbia (MidC) electricity market through a 3.5 GW interconnection. The MidC market is the principal electricity trading hub for the Pacific Northwest, which includes BC and the states of Washington and Oregon. The MidC market is further connected to other trading hubs around the western US and northern Mexico. The MidC market and adjoining regions are modelled as a trading node where BC can buy and sell energy at a predetermined price. This price is based on historical patterns of the MidC market, as described in Section 2.4.

Table 3 presents the installed capacity of generators by type in British Columbia and Alberta for the initial year 2015. With the exception of storage hydroelectricity and BC-US intertie, new generators of any type can be built.

The natural gas price forecast from the Annual Energy Outlook is used to inform the MidC price forecast. Historic monthly economic heat rates for MidC are determined by comparing average daily MidC prices [32] to AECO C natural gas prices [33]. The relationship between these two prices has been consistent over the past five years, with some year-to-year fluctuation related to hydroelectric

[1] The Site C dam is current under construction with an expected in-service date of 2024.

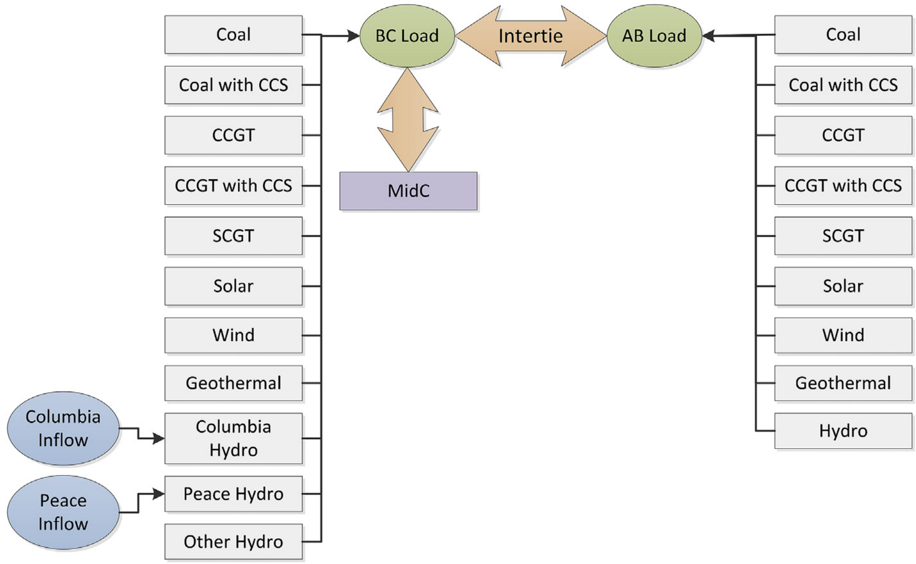

Fig. 4. Schematic drawing of the BC-Alberta electricity system model. CCGT refers to combine cycle gas turbines, SCGT refers to simple cycle gas turbines.

Table 3
Installed capacity by generator type in British Columbia and Alberta as of 2015.

Technology	British Columbia [GW]	Alberta [GW]
Storage hydro	8.63	0
Non-storage hydro	5.06	0.89
Wind	0.55	1.45
SCGT	0	1.00
CCGT	0	1.70
Cogeneration	0	4.63
Coal	0	6.29
Biomass	0.45	0.40
BC-US Intertie	3.5	0
BC-Alberta Intertie	0.76	

energy availability. It was also found that the MidC economic heat rate increases in July of each year (i.e. after the peak freshet). The model uses an economic heat rate of 8,650 MJ/kWh from January to June and 11,200 MJ/kWh from July to December for MidC electricity. It is assumed that losses on BC-US trade are reflected in the purchase and sale prices and therefor are not included in the model. For BC-Alberta trade, losses of 1.5% are included.

Forecasts for hourly demand are taken from BC Hydro's most recent load forecast [34] and the Alberta Electricity System Operator's long-term outlook [26]. This data is extended to 2060 assuming constant growth rates based on the final ten years of the forecasts. Flexibility service requirements (*i.e.* ramping and regulation) are based on the load profiles of BC and Alberta in 2015. Peaking, ramping, and regulation are assumed to increase at the same rates as energy demand in the two jurisdictions respectively.

Carbon policies implemented in the model represent those currently in effect in BC and Alberta, both of which currently have carbon taxes of $30/tonne. In addition, Alberta is assumed to provide Renewable Energy Credits (RECs) for wind and solar generation with a constant value of $25/MWh. This value is based on a previous study that assessed the subsidy needed to incent widespread renewable energy capacity expansion [35]. Finally, the use of coal for electricity generation in Alberta is forbidden from 2030 onward [36]. Alternate carbon policies and technological development pathways are not explored.

The model presented here is able to represent the effects of increasing VR generation on the electricity system over the long term. These effects will impact both the buildout and operation of the electricity system. In this following section, we describe the effects of flexibility requirements as they pertain to the BC-Alberta electricity system.

3. Results

The combined regions of BC and AB are optimized over the period 2015 to 2060. Results are presented to show the cost-optimal transition from today's electricity system to a future low-carbon system, driven by current carbon policies. Installed capacities by generation type are shown in Section 3.1. The energy production and flexibility commitments by generator type are shown in Section 3.2. The commitment of the intertie and BC's storage hydroelectric generators is shown in Section 3.3.

3.1. Installed capacity

The generation mix in BC, shown in Fig. 5(a), does not change significantly over the model period. The two major additions are Site C, which is included in storage hydro, and the intertie expansion. Later in the model period, there are small additions of geothermal and combined cycle gas turbine capacity.

Alberta's generation mix, shown in Fig. 5(b), has a major expansion of wind capacity over the model period, reaching 48.1 GW by 2060. Despite this growth in VR generation, Alberta's fossil fuel generation capacity decreases only slightly. Coal is eliminated by 2030, as mandated by the provincial government (Province of Alberta 2016). Cogeneration is slowly phased out and is eliminated by 2050. Coal and cogeneration are replaced by combined cycle gas turbines and a smaller amount of simple cycle gas turbines. Although natural gas fired generators have high operating costs, this is offset by their flexibility and low capital cost.

Intertie capacity between the two provinces increases from 0.75 GW in 2015 to 7.93 GW in 2060. Intertie capacity, as a fraction of annual average load, reaches 30% in 2046 and remains constant thereafter. This expansion is driven by the cost reductions enabled by trading services between the provinces.

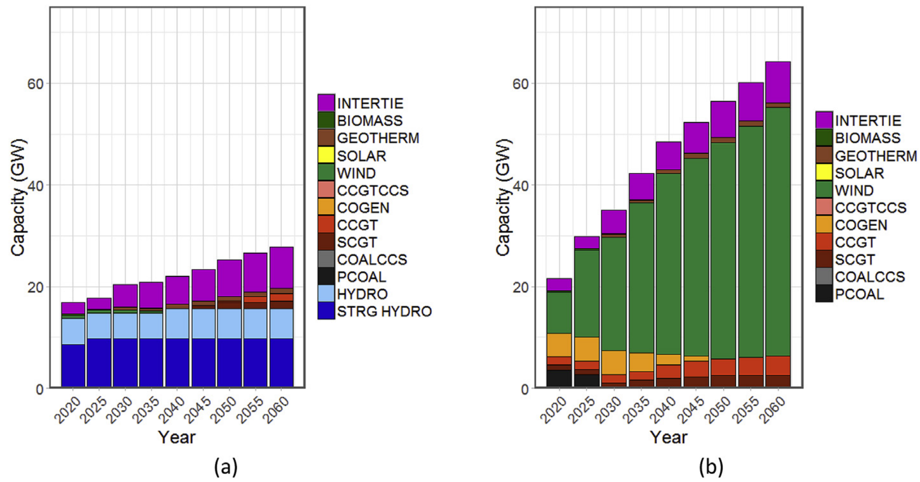

Fig. 5. Installed capacity by type in (a) British Columbia and (b) Alberta from 2020 to 2060.

3.2. Production by source

Fig. 6 shows energy production and unit commitment by generation type to provide each of the four service requirements from 2020 to 2060 for BC and Alberta. Note that the y-axes in Fig. 6 are different in the energy service graphs (*a* to *d*) than in the flexibility service graphs (*e* to *h*). Energy service graphs show the energy generated in TWh. Flexibility service graphs show the capacity committed to providing these services in units of TW-h. The difference between these two units is subtle: energy refers to the actual energy generated, while commitment refers to the amount and duration of the commitment, not necessarily to actual production from a generator.

Baseload in BC, shown in Fig. 6(a), is met primarily by hydroelectricity throughout the model period with the introduction of small amounts of geothermal generation at the end of this period. In Alberta, shown in Fig. 6(b), there is a switch from the current energy mix, led by large amounts of coal generation, to one dominated by wind with a smaller amount of cogeneration. Energy is traded between BC and Alberta at different times of the year, as indicated by baseload imports in both provinces. BC remains close to net-trade neutral over the model period, with a slight trend towards net exports. Alberta begins as a net importer and transitions to net exports, beginning in 2050.

Peaking service in BC, shown in Fig. 6(c), is met by storage hydro with some contribution from gas turbines and imports after 2040. Peaking service in Alberta, shown in Fig. 6(d), is primarily met by both combined- and simple-cycle gas turbines. Both provinces also trade peaking generation at different times, with the most notable occurrence being Alberta's import period from 2025 to 2040.

Ramping commitment in BC, shown in Fig. 6(e), exceeds domestic needs with surplus commitment transmitted to Alberta. A fraction of these imports is used to meet the ramping requirement from load, while the remainder is consumed supporting wind variability. In 2060, 77% of ramping commitment supports variable renewables. This requires an extra 42 TW-h of ramping commitment, corresponding to 4.6 TWh of baseload energy.

Regulation commitment has a similar but less drastic growth. BC provides this service with storage hydro while Alberta primarily uses CCGT and cogeneration with small contributions from coal and in-province hydroelectricity. Unlike the other services, regulation is not significantly traded between the provinces. This implies that the economic and opportunity costs of trading regulation service are greater than those of trading peaking and ramping. Alberta's 8.6 TW-h of regulation commitment corresponds to 4.1 TWh of baseload energy. In total, 6% of Alberta's baseload energy in 2060 is provided by flexibility-committed units.

In the near-term, the modelled results for baseload and peaking agree closely with historical data from BC and Alberta [25]. Less data is available for ramping, which is not a traded energy service, and regulation, for which AESO publishes annual data. For regulation — the model commits gas-fired generators as opposed to the actual hydroelectric commitment [25]. This difference is because Alberta's hydroelectric facilities are not modelled as storage hydro facilities. This means that providing flexibility service would lower the amount of energy these units could produce annually. Instead, the model commits more expensive natural gas generation, which has excess capacity.

3.3. Intertie commitment pattern

Commitment of the intertie varies significantly among seasons. Fig. 7 shows the average commitment of the BC-Alberta intertie by service type from BC to Alberta and from Alberta to BC in each season. Note that this plot shows intertie commitment, not energy.

BC exports, shown in Fig. 7(a), consist of ramping commitment during the fall, winter, and spring and a mix of baseload and ramping during the summer. In return, Alberta exports baseload energy to BC during the spring, fall, and winter. Net intertie commitment remains heavily skewed towards BC exports over the model period. However, because only a fraction of this commitment is used for energy, Alberta exports more baseload energy than it imports beginning in 2050.

This intertie use pattern is a result of the changing annual net load. We define net load for a region as the demand less must-take supplies. For BC, net load is domestic baseload requirement less production from non-storage hydroelectricity; for AB net load is the domestic baseload requirement less production from cogeneration and VR (in this case, wind.) Minimum, average, and maximum seasonal net loads are shown in Fig. 8 (a) for BC (b) for AB.

Alberta net load becomes negative during the fall, winter, and spring seasons beginning in 2030 and remains negative for the rest of the model period. This change is caused by winter peaking of wind generation and low electricity demand in the spring and fall. BC imports excess energy from Alberta where wind capacity factors are high, and does not experience negative net loads. BC's lowest net load occurs in the summer when hydroelectric generation is at its peak and load is at its minimum.

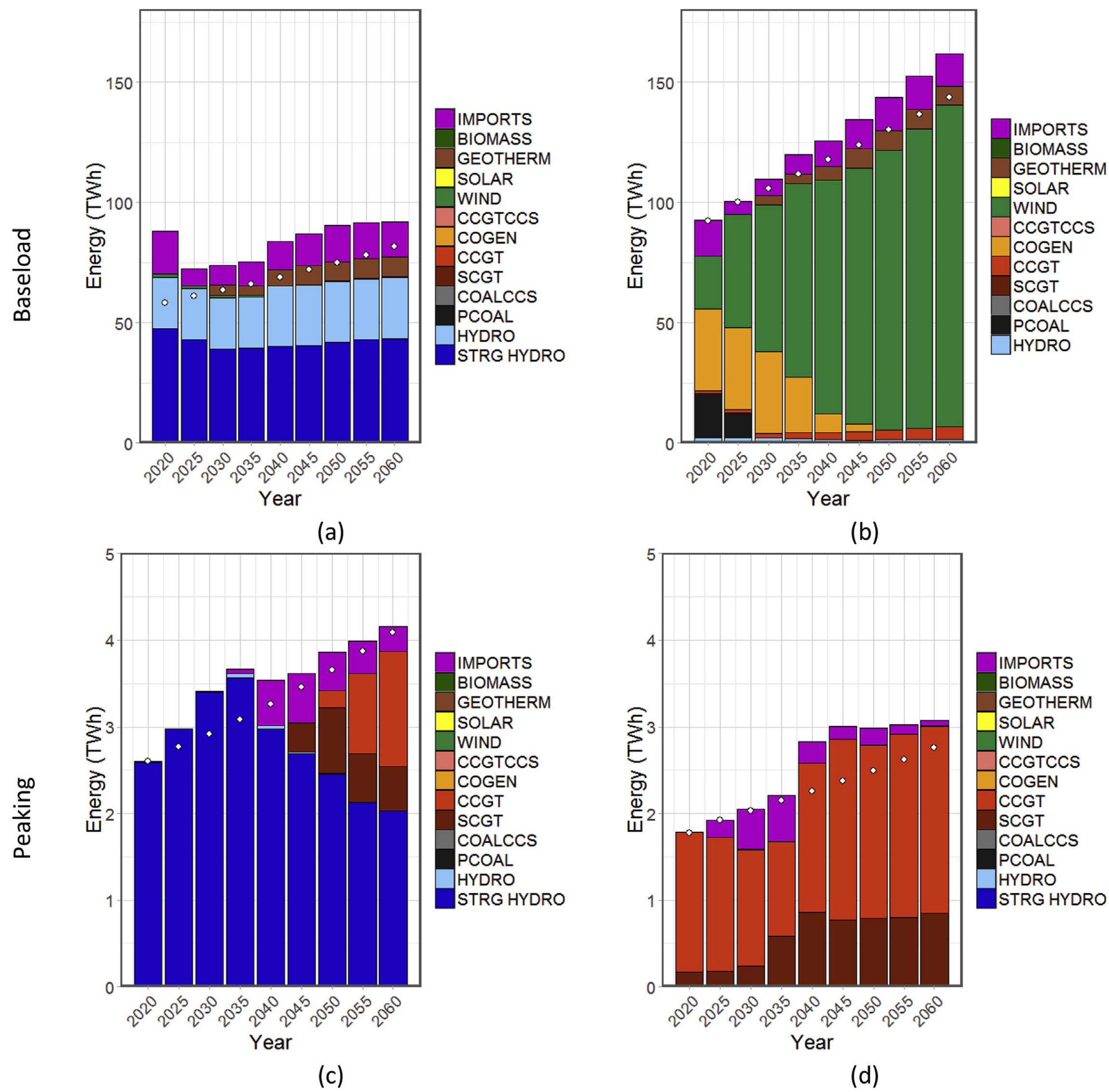

Fig. 6. Energy production and flexibility commitment by generator for each demand in BC (left) and Alberta (right). Dots indicate service requirements based on load not including flexibility requirements from VR generation. Generators are stacked following the order in the legend.

The intertie commitment pattern is driven by these seasonal net load patterns. Initially, BC exports both energy and ramping to meet Alberta's needs. As Alberta expands wind generation, the flow of energy reverses with BC importing energy from Alberta during times of low or negative net load. In return, BC exports ramping capacity to Alberta to meet ramping requirement from load and VR production. BC also exports baseload to Alberta during the summer, when BC's net load is at its lowest and Alberta's is at its highest.

4. Discussion

4.1. Renewable penetration

The results of this study indicate that high penetrations of renewable generation are attainable with current technology and current carbon policies through regional integration. For the model scenario, with a combined region, the market share of wind generation for energy production (both baseload and peaking) reaches 56% in 2060, with 31% of energy provided by hydroelectricity and 7% by geothermal.

This expansion of renewable generation results in a decrease in emissions from 49.3 Mt/yr in 2015 to 5.0 Mt/yr in 2060. While this reduction is significant, it does not meet the reductions outlined in Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, which targets emissions from electricity generation between 0 and 6 Mt/yr nationally by 2050 [37]. This finding suggests that further policy and/or technological changes are necessary to reach a zero-carbon electricity sector.

This buildout of VR capacity requires system flexibility. In this case, flexibility is provided by existing storage hydroelectricity in BC and an expansion of the BC-Alberta intertie. In 2060, storage hydroelectricity provides 79% of ramping commitment and 41% of regulation commitment in the two provinces combined. Storage hydroelectricity is particularly well suited to this role because its energy production is typically limited by water availability rather than installed capacity. This means that the reduced energy production caused by providing flexibility rather than baseload can be offset by higher production at other times. By contrast, a thermal

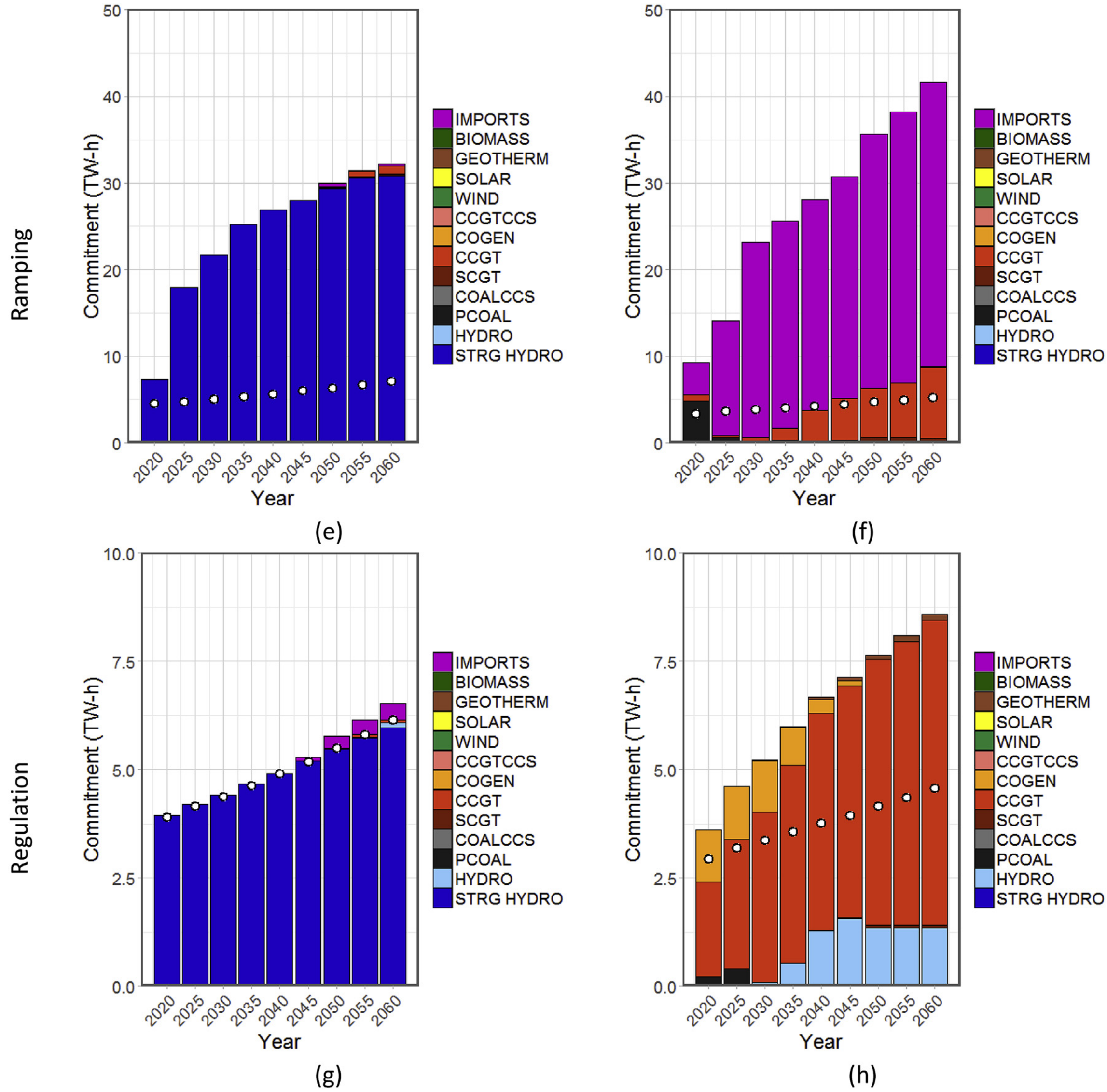

Fig. 6. (*continued*).

generator has a higher opportunity cost when providing flexibility, as it necessarily lowers the generator's annual energy output.

The large-scale buildout of renewable generation causes a shift in the makeup of system costs as outlined in Table 4. In 2015, capital costs are zero because the cost of existing generators are sunk. In 2020, non-variable (*i.e.* capital and fixed) costs account for over half the total system cost. This is predominantly driven by the large buildout of wind in Alberta. By 2060 fixed O&M and capital costs combine for 81% of all system costs. This suggests that, although the higher variability in generation will increase maintenance costs, as discussed by Ueckerdt et al. [2], most of the cost of decarbonizing the electricity system will be in building and maintaining clean energy sources. The shift from variable to fixed costs could necessitate shift away from energy-only markets to encourage investment in flexible generators, as discussed in Refs. [38–40] (see Table 5).

4.2. Net load changes

The high penetration of wind generation in Alberta lowers net load significantly over the model period. Beginning in 2030, Alberta experiences time steps with negative net load, as previously shown in Fig. 8. During these times, Alberta exports its excess baseload energy to BC, displacing baseload generation from storage hydroelectric generators.

Although, by 2060, wind provides 58% of combined baseload energy in BC and Alberta, and non-storage hydroelectricity provides another 11%, there is no time step in which production from these non-dispatchable generators exceeds the combined baseload requirement of both provinces. This is due to the complementary seasonal profiles of these two resources: hydroelectricity peaks in the summer and wind peaks in the winter. If these two resources were to peak simultaneously their combined output would exceed the load in the two provinces, necessitating curtailment.

The annual pattern of net load in BC and Alberta, shown in Fig. 8, follows the same patterns as hydroelectric and wind production. BC's net load is lowest in the summer (JJA) driven by concurrent high hydroelectric production and low load. Alberta's net load is lowest in the winter (DJF) when its wind capacity is producing at its peak. These seasonal differences provide value to the intertie between the provinces.

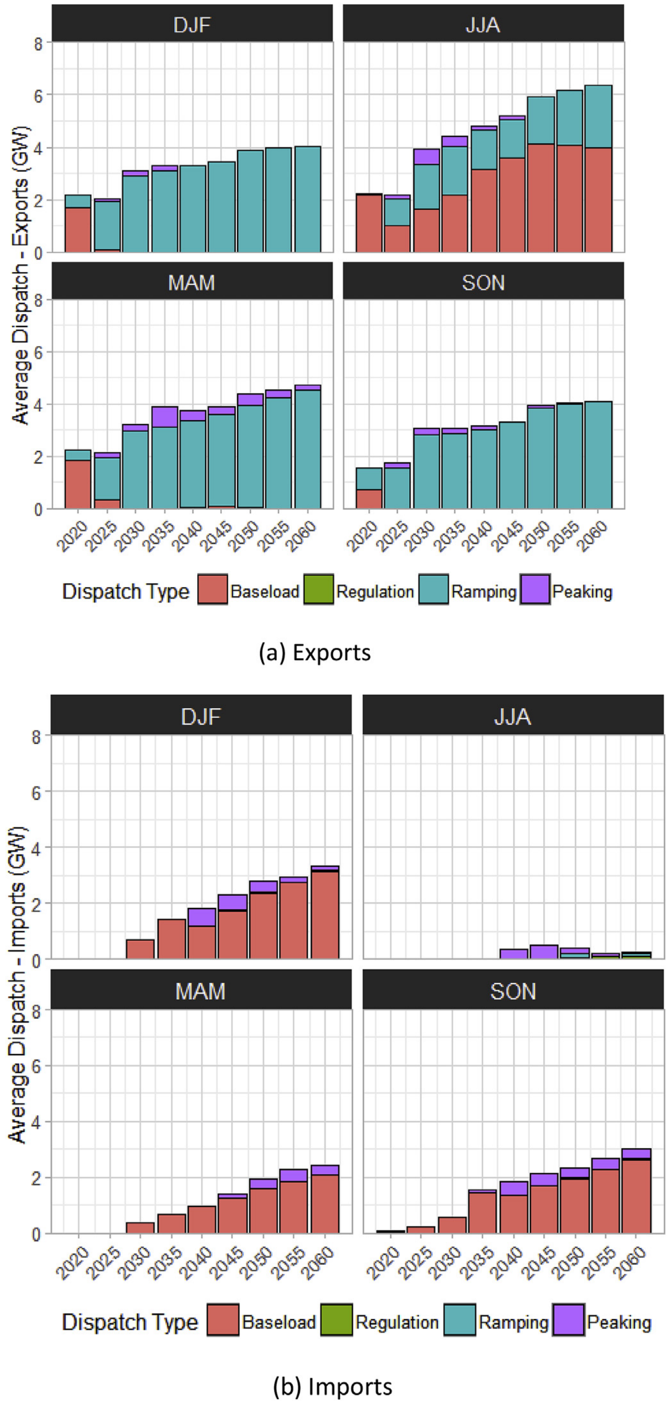

Fig. 7. Commitment pattern of intertie flows from (a) BC to Alberta and (b) Alberta to BC. Commitment is shown for winter (DJF), spring (MAM), summer (JJA) and fall (SON).

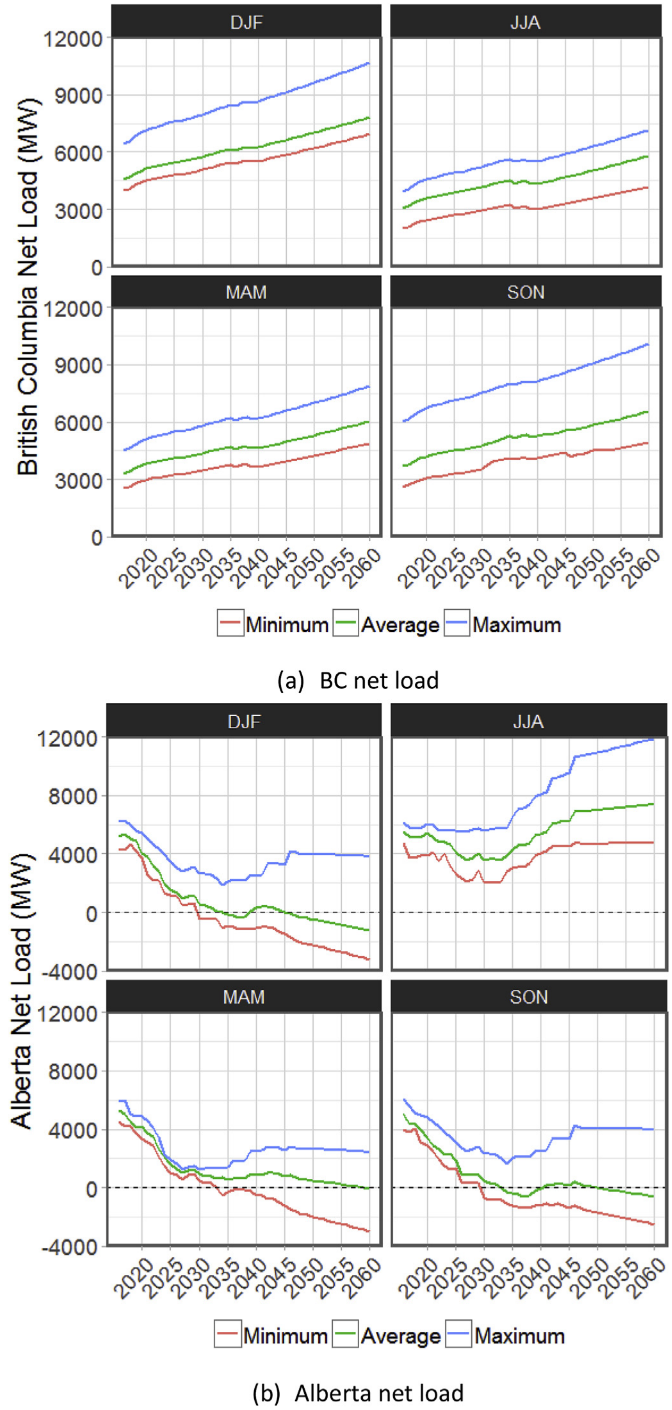

Fig. 8. Seasonal net load patterns in (a) BC and (b) Alberta. Lines indicate the minimum, average, and maximum net load. Net load is shown for winter (DJF), spring (MAM), summer (JJA) and fall (SON).

4.3. Comparison to previous studies

This study expands on previous work that has studied the decarbonisation of Alberta's electricity system alone [41] or alongside British Columbia [18]. Both of these previous works found that low carbon baseload generation, represented by coal with carbon capture and storage, is ultimately selected to provide large amounts of energy. By contrast, in the present study we find that this baseload component can be provided by wind at lower cost, even after accounting for flexibility requirements.

Table 4
Cost breakdown of electricity generation in 2015 and 2060. Capital costs are amortized over the life of the generator.

Year	Cost Component (% of Annual System Cost)				
	Fuel	Variable O&M	Carbon Tax	Fixed O&M	Capital
2015	54%	28%	3%	14%	0%
2025	23%	12%	11%	20%	35%
2060	11%	7%	2%	25%	56%

Table 5
Installed capacity by generator type in British Columbia and Alberta as of 2060.

Technology	British Columbia [GW]	Alberta [GW]
Storage hydro	8.63	0
Non-storage hydro	5.06	0.89
Wind	0.55	48.80
SCGT	1.40	2.48
CCGT	1.55	3.94
Geothermal	1.0	1.0
Cogeneration	0	0
Coal	0	0
Biomass	0	0
BC-US Intertie	3.5	0
BC-Alberta Intertie	8.05	

4.4. Implications for other jurisdictions

While this study focuses on the BC-Alberta power system, the methods and findings has implications for other jurisdictions as well. One such implication is that, in systems with very high VR penetrations, dispatchable generation must exist not only meet a fixed reserve margin but also to provide sufficient flexibility. Flexibility requirements can be readily met by natural gas or hydroelectric generators, but less so by traditional baseload generators like coal and nuclear plants. In this study, cogeneration, which is more efficient but less flexible than CCGT, is phased out in favour of more flexible but costly generation. This is in contrast to recent energy-and-capacity-only studies that find low-carbon baseload generators (*e.g.* nuclear or coal with carbon capture) are prevalent in decarbonized energy systems [18,42–45].

While zero carbon energy is economical under today's carbon policies and technologies, a lack of zero carbon flexible capacity prevents full decarbonisation of electricity generation. In 2060, peaking, ramping, and regulation commitment are equal to 18%, 32%, and 7%, respectively, of average baseload production. However, in energy terms these services account for only 3%, 3%, and 4% of production. Carbon free technologies that are economical under low capacity factor operation and that can manage frequent, steep ramps in output are necessary to fully decarbonize electricity generation. These technologies may include hydroelectricity, as shown in this study; energy storage, as explored in Refs. [7,10,46,47]; by adopting zero-carbon fuel sources for fast-ramping generators [48]; through the use of demand response [49,50], or by equipping conventional generators with carbon capture [51].

In this study, the intertie between BC and Alberta is used primarily to transmit ramping commitment, as shown in Fig. 7. This trade of ramping commitment is enabled by BC's large hydroelectric storage capacity. Another use of the intertie, which is applicable to jurisdictions without storage hydroelectricity, is to transmit surplus VR energy between the provinces. This interconnection enables the development VR sources with complementary seasonal profiles as there is a wider pool of resources from which to choose. This resource diversity reduces net load variations, particularly at long time scales, as explored in Refs. [3,5]. For BC and Alberta these resources are hydroelectricity and wind. Other regions may have similar resource complementarity such as complementary wind profiles or solar and wind production.

Despite its decreasing cost, solar generation is not installed during the model period. This is, in part, a result of solar's high daily output range. Solar generation changes from full capacity to zero output over the day while wind generation is more evenly spread over the day. Solar generation thus requires more capacity in backup generation than the same amount of wind generation. While previous studies have found that hydroelectricity can provide this backup capability, the results of this study suggest that the flexibility of existing hydroelectric generators is better used to provide flexibility for wind rather than solar. This may change in regions with better solar or worse wind resources where the lower cost of energy offsets the higher backup capacity requirement. More significant reductions in solar capital cost may change the specific mixture evolution; however, it is unlikely to impact the main findings regarding the need for flexibility.

4.5. Model limitations

In the later stages of the model period, Alberta frequently exports baseload energy to BC at the same time as BC is exporting ramping flexibility to Alberta. In the model, this requires intertie capacity equal to the sum of these components. As a consequence, the actual required intertie capacity and, by extension, the intertie cost would be less than is indicated in the model because the same intertie capacity would provide both services. However, the capital cost of the intertie is a small fraction of total model costs (<1%), so this effect likely does not significantly affect the results.

As modelled, wind generation in Alberta is less expensive than wind generation in BC. This is a reflection of the operation of current wind generators; generators in Alberta typically have a higher capacity factor than those in BC. However, given the large buildout of wind in the model results, it is likely that some of the wind generation installed in Alberta would be more economically placed in BC. Moving a portion of this generation into BC would reduce the disparity in net load and flexibility requirements between provinces, although total requirements would remain unchanged. This would result in reduced need for intertie capacity. Addressing this question would require a spatially resolved supply stack for wind, a topic of future work.

This study is based on a single forecast for the price of fuels and technologies over the model period. Changes to these forecasts could impact the outcomes of the optimization. For example, if the price of solar panels falls more than expected, solar may begin to displace or supplement wind generation. Widespread adoption of solar PV in the US could also change the price of electricity at the MidC market. These changes could impact the ultimate generation mix of the electricity system.

In the model the flexibility requirement for VR production is defined as a constant fraction of VR energy. As more VR generation is adopted, geographic diversity may result in a flatter generation profile, thereby lowering flexibility requirements, as shown in Refs. [52,53]. However, because the flexibility requirement of VR generators depends heavily on the VR production profile in a region, this ratio is very location-specific and could be higher than estimated in studies from other regions. Increasing this requirement would increase the capacity required to provide these services, and therefor increase the role of natural gas generators. Similarly, a lower requirement would reduce the amount of natural gas generation required.

The time steps used in the model lose some of the short time scale variations in load and generation. One important implication of this is that overgeneration is often smoothed away. For example, even if VR generation exceeds load for many of the 274 h that make up an average time step, the model does not curtail VR generation unless the average VR generation is greater than the average load. Accurately modelling curtailment is an important addition to be added in future studies.

The model used here does not include discrete effects that may impact the operation of the electricity system. For example, generator and transmission outages could impact the ability to manage power fluctuations. This is of heightened importance when there is a reliance on interprovincial trade to maintain load balance. Addition studies are needed to determine the best way to structure the system in terms of specific resource additions to maintain a reliable system.

Despite these limitations, the model used in this study provides an improved representation of the long-term expansion and operation of an electricity system compared to energy-and-capacity-only studies. The four services approach used here provides more resolution of the electricity system than treating electricity as a single service. A key implication of this improved representation is that the complementarity of hydroelectric and VR production, which has been previously shown in short-term studies only [6], is sufficient to incent transmission expansion to link these resources. Additionally, the four-service model used here captures the value of flexibility. As a result, instead of low-carbon baseload generators being a major driver of decarbonisation, as presented in Refs. [18,42–45], the results of this study indicate that a combination of VR and flexible generation is optimal.

5. Conclusion

This study investigates the cost-optimal transition of a thermal-dominated electricity system to a renewable-dominated system through carbon policies and increased interregional transmission. Recent studies have shown that interregional transmission can be used to mitigate some of the negative effects of VR generation, particularly net load variability. Using a long-term optimization model we show the potential for transmission between BC and Alberta to enable high levels of wind generation under current carbon policies.

The model used in this study includes flexibility requirements in addition to the traditional energy and capacity constraints found in many energy systems models. This inclusion allows the benefits of fast ramping generation, and the limits of VR generation, to impact investment and dispatch decisions. As the system switches to a VR-dominated generation mix these factors have increasingly large effects. In the long-term, the need for flexibility results in more efficient but less flexible generators being replaced by those that are less efficient but more flexible.

Although the results show deep decarbonization occurring over the model period, the system never reaches a zero-carbon level. This is a result of the need for flexible generation to offset the variability in VR production. While hydroelectricity provides some of this flexibility, there is insufficient hydroelectric capacity to meet the needs of a high-VR system. Existing hydroelectric generators are supplemented by a combination of SCGTs and CCGTs providing peaking, ramping, and regulation services. In order to completely decarbonize the electricity sector, technologies to provide flexibility services and the policy and market environment to support these technologies are necessary.

The expanded intertie allows flexible generators in one province to provide flexibility services in both provinces. This allows lower cost flexible generators, such as hydroelectricity, in one region to offset the need for more expensive flexibility in the neighbouring region. At the same time, the intertie allows renewable resources with complementary profiles, such as summer-peaking hydroelectricity and winter-peaking wind generation, to be traded between regions, allowing higher penetrations of renewables than would otherwise be possible. These two value components, flexibility and resource complementarity, mean that interregional transmission can, in some cases, provide more services at lower cost than local options such as fast-ramping generators and resource diversification.

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