Examining the contribution of hydroelectric renewal and greenfield development to grid decarbonization: An enhanced capacity expansion model[1]

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Abstract

While the Canadian electricity system is predominantly hydroelectric, it also includes coal, natural gas, diesel and variable renewable generation. In this paper, we evaluate competing scenarios for grid decarbonization, including carbon prices, advanced retirement of high-emitting generation capacity, and expansion of the inter and intra provincial transmission network. Our mixed integer linear programming capacity expansion model includes hourly wind speed and solar irradiation data for 2278 locations in Canada, hourly demand data for each province, and inter- and intra-provincial transmission capacity constraints. However, this work focuses on the potential of hydroelectric renewals, including capacity expansions, efficiency upgrades and pumped storage additions at existing hydroelectric facilities to deeply decarbonize the electricity system. Our results show that existing coal-fired generation is removed from the Canadian electricity system with a carbon price of $50/t or higher, but even a carbon price of $200/t is insufficient to remove all natural gas generation. With a $200/t carbon price, hydroelectric resources play an important role in the future electricity system, with nearly 1,500 MW of hydroelectric renewals by 2030 and an additional 1,500 MW of greenfield hydroelectric developed prior to 2050.

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1 Introduction

Canada's First Ministers recently committed to a clean electric future of affordable and reliable electricity (Government of Canada, 2018) in support of Canada's pledge to reduce economy-wide greenhouse gas (GHG) emissions by 30% below 2005 levels by 2030 (Government of Canada, 2017). Analyses indicate that deep decarbonization of Canada's economy entails widespread electrification in the transport, industry and building sectors, resulting in large increases in electricity demand, and a vast build-out of variable renewable energy (VRE), especially wind and solar (Bataille, et al., 2015), (Vaillancourt, et al., 2017). This build-out requires low-carbon balancing resources capable of integrating VRE while providing dependable capacity, energy storage, and grid ancillary services. To realize this emissions reduction objective and to evaluate pathways to its achievement, policymakers and planners require information concerning costs, development timeframes, operational reliability, and GHG emissions of competing alternatives, including of new and expanded transmission corridors.

Over the past several decades greenfield hydroelectric development has been the preferred low-carbon electricity balancing resource across Canada (Canada Energy Regulator, 2019). Recent analyses of future deep decarbonization (Bataille, et al., 2015), (The Canadian Academy of Engineering, 2016) also propose a large buildout of greenfield hydroelectric generation. While this is unsurprising considering Canada's many and large rivers, these prior analyses omit consideration of capacity expansions, efficiency upgrades and pumped storage additions at existing facilities, collectively referred to in this report as "hydroelectric renewals". These hydroelectric renewals offer many potential advantages over their greenfield counterparts including lower capital costs, lesser environmental impact, reduced development timelines, and higher likelihood of acceptance by affected local communities. For example, while recent large-scale greenfield hydroelectric projects have required an average of 20 years from conception to operations,[2] potential hydroelectric renewals totaling several thousand megawatts (British Columbia Utilities Commission, 2017), (Alberta Electric System Operator, 2018) have development timelines of less than 10 years (BC Hydro, 2013b). Pumped storage hydroelectric, whether developed as standalone technology or at existing hydroelectric reservoirs, offers similar advantages of reduced environmental footprint and shorter development timelines compared to large-scale greenfield hydroelectric (Knight Piésold Ltd., 2010). As such, hydroelectric renewals and pumped storage hydroelectric could contribute meaningfully to Canada's 2030 emissions reduction targets. The question of how to renew and develop available hydroelectric resources is therefore central to addressing the electricity requirements of low-carbon electrification in Canada.

To explore this question, we develop a capacity expansion model for Canada with the ability to evaluate and compare policy and technology options, including the desirability of investing in hydroelectric renewals versus greenfield hydroelectric, pumped storage versus battery storage, or transmission versus energy storage or new generation. The model develops an improved characterization of hydroelectric facilities in terms of storage duration, fuel constraints and redevelopment, while assembling a detailed database of costs, capacity and operations of potential future hydroelectric renewal and greenfield projects.

The remainder of this report is organized as follows. **Section 2** describes the model design, including its objective and constraints, spatial and temporal resolution, inputs, outputs and methods. Where the model was improved, the "model enhancements" are described and summarized at the end of this section. **Section 3** discusses the model's results, highlighting significant observations in relation to generation, transmission, costs and emissions, including the role of hydroelectric renewals, pumped storage and

[2] Including BC Hydro's Site C Clean Energy Project, Nalcor Energy's Muskrat Falls Project, Manitoba Hydro's Keeyask Project and Hydro Québec's Complexe de la Romaine.

greenfield development in system decarbonization. **Section 4** situates the chosen model, referred to as Canadian Renewable Electricity Storage and Transmission (CREST), in the context of the broader modelling ecosystem, and envisions synergies with other models and modelling efforts.

Readers should note that this report and the modelling work herein represent the first step in a three-year modelling effort. In submitting this report at this early stage in the research, the authors are seeking the input of the EMI network on future improvements and expansions as well as how we might collaboratively fill several data and information gaps.

To this end, **Section 5** summarizes key observations made throughout the report including: energy modeling data gaps and requirements that place limitations on the model ("model limitations"), proposed future model improvements ("model opportunities"), and policy considerations ("policy implications") for further discussion with the EMI network.

2 The Model

2.1 Design

i. Linear to mixed-integer linear program

The precursor to CREST was configured as a linear program model (Dolter & Rivers, 2018), optimizing the development of the national electricity system on the basis of least total cost. As a linear program, the model developed new generation resources on the assumption that the cost curve of the available resources could be approximated as a continuous function. In other words, the model filled gaps between demand and supply by selecting the next lowest cost megawatt from the stack of available generation resources. While this approach is appropriate for modelling modular assets such as wind, solar and battery storage, it is not appropriate for hydroelectric renewals, pumped storage and greenfield hydroelectric, which are discrete and spatially-constrained. As such, CREST is reconfigured as a mixed integer linear program optimization model capable of making integer-type decisions in addition to continuous-type decisions in order to evaluate future development and redevelopment (repowering or recontracting) of hydroelectric resources, which are larger-scale, spatially confined and can only be developed as "all or nothing" resources. Currently, CREST models only hydroelectric and pumped storage generation resources as integer variables, and applying this approach to other non-modular potential new generation resources (e.g. nuclear, geothermal, natural gas combined cycle) would improve the predictive accuracy of the model by treating all large-scale resources as "all or nothing".

Model Enhancement #1: CREST is reconfigured as a mixed integer linear program optimization model.

Model Opportunity #1: Future iterations of CREST could model all potential non-modular generation resources as integer-type decisions (e.g. nuclear, geothermal, natural gas combined cycle) similar to the current approach used for hydroelectric renewals, pumped storage and greenfield hydroelectric.

ii. Model objective and constraints

This section provides an overview of the objective function and constraints used in CREST, while detailed model notation is provided for reference in Appendix A. CREST minimizes the total investment and operating costs of a given electricity system by making investments in generation and transmission technologies and optimizing their hourly dispatch over the course of a year (i.e. 8760 hours). Total annual cost includes annualized capital costs, fuel costs, fixed operations and maintenance costs, variable operations and maintenance costs, and carbon pricing costs.

$$\boldsymbol{Min.total\ cost = capitalcost + \ fuelcost + fixcost\ + \ \ varcost + carbon\ costs.}\ \ (\mathbf{1})$$

Details on the underlying assumptions and inputs for determining the various costs in relation to generation and transmission assets used in the model are provided below (2.2).

CREST makes use of several constraints, pursuant to system, reliability, economic and policy criteria. Key constraints within the basic configuration of the model include (Dolter & Rivers, 2018):

- Electricity supply must be equal to or greater than electricity demand in each hour and within each balancing area;
- Total hourly dispatch from electricity generation assets must be less than or equal to total installed generating capacity;
- Total hourly electricity transmitted between balancing areas must be less than or equal to available transfer capacity between those balancing areas;
- The density of wind installations in each grid cell must be less than 2 MW per km^2 (GE Energy Consulting, 2016); and
- The density of solar installations in each grid cell must be less than 31.3 MW per km^2 (Ong, et al., 2013).

All constraints and related equations are provided in Appendix B. Decision variables in CREST include investment in new electricity generation, pumped storage and transmission capacity, retirement of existing capacity, and hourly dispatch of available technologies to meet hourly electricity demand over the course of a full year.

iii. Spatial and temporal resolution

CREST employs a network of grid cells, referred to as *locations*, for delineating geographic variation in the performance of wind and solar resources. Though spatial data has been obtained for all generation in the model, and all generation can be similarly mapped to these locations, demand data is not yet available at a comparable spatial distribution. Therefore, though the site-specific generation of wind and solar resources is modelled at the locations in order to capture climatic and topographic variations in generation, the overall balance of supply, demand and transmission of electricity is modelled at a lower geographic resolution.

Model Limitation #1: CREST currently models the overall balance of supply, demand and transmission of electricity at a lower-than-desired geographic resolution. Hourly demand data spatially disaggregated at a regional or substation level would permit CREST to make fuller use of its analytical capabilities.

This lower resolution consists of *balancing areas*, which are aggregations of grid locations and form the model's primary geographic unit. Each province corresponds to a single balancing area, with the exception of Ontario, Quebec, and Newfoundland and Labrador where the northern and southern portions of the provinces form independent balancing areas. In the absence of demand data by location, significant improvements in model resolution could be achieved by increasing the number of balancing areas, since regional demand data is available at the zonal level within some balancing areas (IESO, 2019d). This is particularly beneficial within larger provinces where the balancing areas are spatially large, reducing the accuracy of model optimization in locating new generation. This opportunity also relates to model performance respecting the development and costing of transmission assets, and is discussed further below (s.2.2vi).

Model Opportunity #2: Increasing the number of *balancing areas* within CREST would improve model performance in locating and costing new generation and transmission resources.

Temporally, CREST models the variation in electricity supply and demand at hourly intervals. This is in part the consequence of the temporal resolution of the available electricity demand data, but is also at sufficient resolution to capture some of the daily variation in the performance of different generation assets, particularly hydroelectric resources whose performance and system value vary depending on the duration of the available energy storage (s.2.2v). By modelling electricity systems over the course of an entire year (8760 hours), CREST also captures seasonal variations in electricity supply and demand.

Currently, the model allows for the selection of the target year(s) for the analysis, with the years 2030 and 2050 selected for this report, using a baseline year of 2018. A significant improvement in CREST would entail the ability to model time-dependent changes in the electricity system, that is by making the outputs of one analysis period the inputs of the subsequent analysis period. The conversion of CREST in this manner from a static cross-sectional model to a dynamic longitudinal model is under consideration by the authors. A dynamic model would have greater utility for policymakers, allowing assessment of the effects of policy changes over time and not only at particularly points in time. Potential drawbacks of conversion to a dynamic model include substantial increases in computational time.

Model Opportunity #3: Converting CREST from a static cross-sectional model to a dynamic longitudinal model would allow for the assessment of the effects of policy changes over time.

In terms of temporal supply and demand uncertainty at the operational level, CREST presumes that the system operator has perfect advance knowledge of generation availability and outputs, as well as system hourly demand. While this is a limitation to the model, this potentiality is not considered necessary for CREST and is better developed within a production cost modeling framework, as discussed further below in the context of synergies with other models (4.3iii).

2.2 Inputs and methodology

i. Common data sets

CREST makes maximal use of existing provincial and national databases and information sources, including those made public by utilities, system operators, regulators and energy associations. Where data is assembled for unique objectives, such as the modelling of hydroelectric renewals in CREST, that data can be made available to other researchers outside of our team network. Of particular interest to our research is the ongoing project being undertaken by the Canada Energy Regulator to model future hourly electricity demand at the provincial level across Canada (Canada Energy Regulator, 2019).

ii. Electricity demand

Hourly electricity demand data (Table 1), is sourced from provincial electricity utilities and system operators for the year 2018, the baseline year for modeling. Most utilities and system operators make hourly internal demand and total demand data (including imports/exports) publicly available, with some also providing interprovincial and international intertie flows.

As summarized in Table 1, hourly data for 2018 is not available for all provinces and all intertie flows. This necessitated the use of 5-year demand (GWh/year) growth factors on the 2013 hourly data, which was available for all provinces. This approach imposes meaningful limitations on the findings of the current analysis since it presumes (incorrectly) that hourly demand shifts uniformly year-to-year in response to changes in annual total electrical energy demand.

Model Limitation #2: The absence of 2018 hourly load data for some provinces required use of modified 2013 hourly load data, which presumes (incorrectly) that hourly demand shifts uniformly in response to changes in annual total electrical energy demand.

Forecasted annual electricity demand is also sourced from provincial utilities and system operators, most of whom regularly produce long-term annual energy demand (GWh/year) and peak demand (MW) forecasts, before and after the effects of demand-side management (DSM). The forecast period and duration of these forecasts vary between utilities, as summarized in Appendix C – Table 7. CREST modeled growth rates shown in the table for the 2018-2030 period are taken as the average of annual forecast growth rates in utility "mid-load" (i.e. P50[3]) energy demand net of DSM over that period. For the period 2018-2050, the longest available average annual mid-load forecast growth rate is used as the modelled growth rate. Some utilities also produce "low-load" (P90 or P80) and "high-load" (P10 or P20) forecasts reflecting lower or higher anticipated demand growth coupled with better or worse performance of DSM measures, all of which can be modeled in CREST.

Table 1: Availability of electricity data

Province	2018 Hourly Internal Load	2018 Hourly Total Load	2018 Hourly Facility Generation	2018 Hourly Intertie Flows	Annual Energy Demand 2013-2018	Sources
British Columbia						(BC Hydro, 2019)
Alberta						(AESO, 2018)
Saskatchewan						(Saskpower, 2019)
Manitoba						(Manitoba Hydro, 2018)
Ontario						(IESO, 2019b), (IESO, 2019a) (IESO, 2019c)
Québec						(Régie de l'énergie du Québec, 2019)
New Brunswick						(NB Power, 2019)
Prince Edward Island						(NB Power, 2019), (Maritime Electric, 2018)
Nova Scotia						(Nova Scotia Power, 2019)
Newfoundland and Labrador						(Nalcor Energy, 2019)

Province	Hydro Operations	Hydro Reservoirs	Thermal Operations	Thermal Costs	Substations	Transmission
	Head, Discharge, Ramping	Levels, Storage	Start/Shut Heat Rates, Ramp Rates Min/Max Power, Up/Down Times	Start/Shut, Cycling, Ramping	Names, Geospatial, Voltages	Lengths, Ratings, Substations
British Columbia					Geospatial	Ratings
Alberta					Geospatial	Ratings
Saskatchewan					Geospatial	Ratings
Manitoba					Geospatial	Ratings
Ontario					Geospatial	Ratings, Substations
Québec			n/a	n/a	Geospatial	Ratings, Substations
New Brunswick					Geospatial	Ratings
Prince Edward Island	n/a	n/a			Geospatial	Ratings
Nova Scotia					Geospatial	Ratings
Newfoundland and Labrador					Geospatial	Ratings

Data available:	
Data partially available:	Missing data
Data unavailable:	

[3] P50 means 50% probably of being exceeded.

Basing modeled growth rates on averages of forecasts for annual energy demand growth net of demand-side management introduces several limitations. First, annual energy demand does not grow linearly year to year, and interannual variations that may otherwise trigger development of new generation resources may not be fully represented in CREST. This limitation could be addressed through the use of hourly load forecasts, which would better encapsulate seasonal and diurnal fluctuations in demand. We understand such hourly forecasts are currently in preparation by the Canada Energy Regulator for each of the provinces to the year 2030 (Canada Energy Regulator, 2019).

Secondly, annual load growth does not reflect changes in hourly load growth or growth in peak demand. Utility forecast rates for peak demand growth are generally lower than those for annual energy demand, though our review indicates that this varies considerably between utility forecasts. This limitation could also be addressed through the use of hourly load forecasts, since these would include forecasted peak hourly demand.

Model Limitation #3: The use of forecasts of annual energy demand in CREST introduces limitations that could be addressed through the use of hourly energy demand forecasts, which the authors understand are currently under development by the Canada Energy Regulator.

Third, the use of short-duration load forecasts (e.g. the three-year PEI forecast) introduces greater probability for error when projecting that forecast forward many years into the future. This could be addressed by the utilities and system operators producing 20-year forecasts of annual energy and peak demand, including both before and after the effects of DSM, not less frequently than every two years. While there remains uncertainty in any load forecast, that uncertainty can be better quantified using a 20-year forecast and would represent an improvement over short-term three-year forecasts.

Model Limitation #4: The use by CREST of utility and system operator load forecasts introduces errors in estimation that could be addressed by utility and system operators producing 20-year forecasts not less frequently than every two years. These load forecasts should include low, mid and high forecasts that reflect existing decarbonization and electrification policies, as well as “electrification forecasts” that reflect an estimate of low-carbon electrification required to fully achieve greenhouse gas emissions reduction objectives.

The utility mid-load forecasts in Appendix C – Table 7 incorporate the prevailing federal and provincial policies, codes and standards in place at the time of the forecasts. These policies do not generally reflect additional low-carbon electrification that may need to occur in order for the given provincial jurisdiction to contribute to meeting Canada’s pledge to reduce economy-wide GHG emissions by 30% below 2005 levels by 2030. For example, BC Hydro’s load forecast is based on the requirements and associated incentives within the CleanBC Plan (BC Hydro, 2019), though the Plan contains measures designed to achieve only 75% of the province’s committed reductions in GHG emissions by 2030 (Government of British Columbia, 2018). This suggests that the mid-load forecasts underestimate, and in some cases likely significantly underestimate, the increases in electricity demand that would result from low-carbon electrification necessary to achieving Canada’s 2030 GHG emissions reductions objective.

The mid-load forecasts also reflect the proposed DSM efforts on the part of the utilities and system operators. A recognized standard for comparative evaluation of utility DSM performance is the annual incremental energy savings as a percentage of total domestic demand. High performing North American utilities consistently score above 1.5% in DSM savings per year, with some utilities consistently achieving 2.5% in DSM savings per year (Efficiency Canada, 2019) (Manitoba Hydro Public Utilities Board, 2014). Over the duration of the respective forecast periods, for the six utilities for which data were available, these average annual percentages are: 0.33% (BC Hydro), 0.17% (Saskpower), 0.50%

(Manitoba Hydro), 0.25% (Hydro Québec), 0.75% (NB Power), and 0.72% (Nova Scotia Power). These findings are consistent with those of a recently released review of the three-year (2016-2018) electricity DSM performance of the provincial utilities and system operators, which determined that annual average DSM performance ranged from 0.2% (PEI) to 1.41% (Ontario) (Efficiency Canada, 2019). This suggests that the mid-load forecasts overestimate the increases in electricity demand were investment in DSM to be increased to levels consistent with North American utility standards.

iii. Generation technologies, costs and emissions

Installed electricity generation for the baseline year, and future planned generation are identified for each balancing area and province. Data is sourced primarily from utilities and system operators, supplemented with information from independent power producers, government agencies and regulatory filings. Additional generation spatial information is gathered from the World Resource Institute *Global Power Plant Database* (World Resources Institute, 2019). Only facilities with installed capacities larger than 1 MW and interconnected to a provincial transmission grid are included in the analysis.

Our research identified in excess of twenty different types of generation, including thermal, renewable and storage technologies operating within provincial electricity systems. To streamline this initial analysis, the existing forms of generation are categorized into one of the generation technologies listed in Appendix C – Table 8. The use of a limited number of thermal generation types places some limitations on the analysis, particularly in terms of the determination of system costs and the estimation of system-wide greenhouse gas emissions. Additional limitations from this initial analysis result from the exclusion of battery storage, geothermal generation and carbon-capture and sequestration, among other potential economically and technically feasible low-carbon generation sources. Overall system-wide costs might be reduced through inclusion of these other generation sources.

Model Limitation #5: The limited number of thermal generation types represented in CREST results in errors in the estimates of system-wide costs and greenhouse gas emissions.

Model Limitation #6: The exclusion of battery storage, geothermal generation and carbon-capture and sequestration may be precluding opportunities to reduce modeled estimates of future system costs.

Model Opportunity #4: Future iterations of CREST could further disaggregate thermal resources and add additional low-carbon resources (e.g. geothermal) to the potential asset list used in the model.

For each facility, information gathered includes: installed capacity (MW), average annual energy (GWh/year), latitude/longitude, balancing area, grid location (for wind and solar facilities), start year and end year. Start years and end years may be either the scheduled date for commissioning or decommissioning the facility or the schedule commencement or termination date of the facility's power purchase agreement with the utility or system operator. The use of start and end dates allows for the model to consider repowering wind and solar (2.2iv) as well as hydroelectric generation (2.2v), which are anticipated to be recontracted upon contract termination.

The generation available to meet internal provincial demand consists of the installed capacity net of any capacity contracted for import or export with neighbouring jurisdictions, including for export to the United States. Long-term contracts between provincial utilities for the sale and purchase of dependable (non-interruptible) capacity are summarized in Appendix C – Table 9.

Contracts for seasonal capacity, interruptible capacity and energy only are not currently addressed in the model. Future iterations of CREST could consider improvements to the characterization of interprovincial contracts in the context of improved hourly data for current and forecasted demand and for intertie transfers.

Model Opportunity #5: The characterization of interprovincial contracts for energy and capacity within CREST could be improved with the availability of hourly demand and intertie flows between each Province.

On the basis of the installed capacities and scheduled end dates, as well as long-term contracted capacities, extant capacities are determined for the baseline year (2018) and target years (2030 and 2050). Installed capacity by generator type across Canada in 2018 is shown in Figure 1, and for each generator type within each balancing area in Figure 2.

Figure 1: Canadian installed capacity in 2018

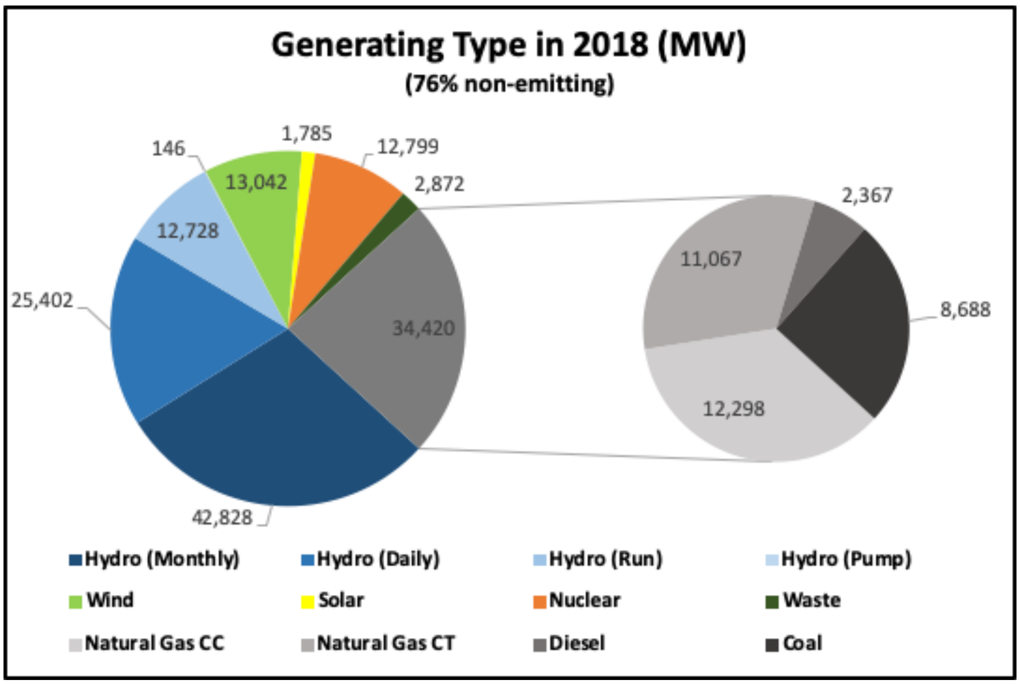
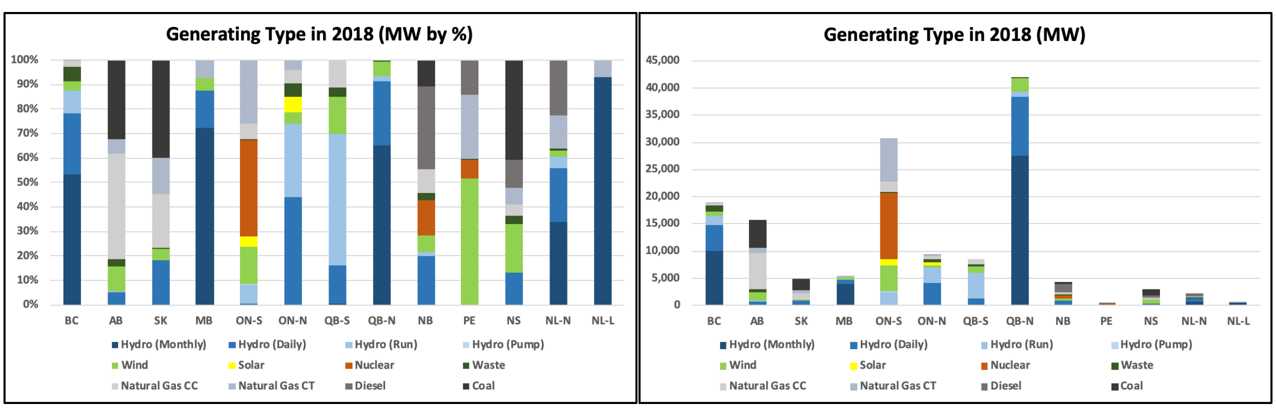


Figure 2: Balancing area installed capacity in 2018



CREST models the ability of different generating types to ramp in response to changes in demand and intermittent supply. Since CREST models capacity requirements by balancing area on an hourly basis, fleet hourly ramping rates, which reflect the collective ramping rate of a group of generators of a similar type, are more appropriate than sub-hourly ramping rates associated with individual facilities or units. The use of sub-hourly ramping rates could overstate the flexibility of the system to integrate VRE and to respond to demand fluctuations. A review of hydroelectric and natural gas fleet ramping rates in the United States found as follows:

> The average one-hour ramp for the hydropower fleet (as a percentage of installed capacity) is greater than for natural gas in all ISO/ RTOs. In addition, hydropower adjusts its output up or down by more than 5% of its installed capacity from one hour to the next more frequently than natural gas, especially in the ISO/RTOs with most PSH capacity. Nevertheless, natural gas follows net load more closely (i.e., its ramps are more highly correlated with net load than those from the hydropower fleet) likely due to the fact that its operations are not subject to the restrictions experienced by hydropower due to non-power purposes of storage reservoirs, minimum flow requirements, or water quality constraints (U.S. Department of Energy - Waterpower Technologies Office, 2018).

This research suggests that, on an hour-to-hour basis, hydroelectric systems may have greater flexibility compared to thermal systems, despite the latter's advantage in the minute-to-minute timeframe. The Waterpower Technologies Office study found that the natural gas fleet ramping rate averaged 5% per hour across balancing areas, while the hydropower fleet ramping rate averaged 10% per hour, with values approaching 15% in those regions with significant pumped storage capacity (U.S. Department of Energy - Waterpower Technologies Office, 2018). We undertook a review of hourly generation for all generation types on the IESO (Ontario) grid over the course of an entire year, and made similar observations for natural gas and hydro, as well as for other generating technologies. That investigation resulted in adjustments to the ramping rates used in CREST, as shown in Appendix C –

Table 10. It is important to note that the observed performance of generating fleets may not reflect their potential performance, which could be more flexible were the marketplace to require (and reward) such flexibility. The values in Appendix C –

Table 10 are considered interim, and additional research is required concerning the appropriate fleet ramping rates for use in CREST.

Model Limitation #7: Additional research is required concerning the appropriate fleet ramping rates for use in CREST.

iv. Wind and solar generation

Existing and planned wind and solar generation are identified for each balancing area, and geo-located within one of a series of 2278 grid locations south of 60° latitude in Canada (each grid cell is one-half degree by two-thirds of a degree). The modelling of wind and solar resources at this resolution allows CREST to incorporate differences in generation per installed megawatt resulting from climatic and topographic variations across the country.

Historical hourly wind and solar generation time series data is calculated using the Global Renewable Energy Atlas & Time-series (GRETA). A free web-based tool, GRETA produces hourly wind and solar photovoltaic (PV) generation time series for any location on the global Modern-Era Retrospective Analysis for Research and Applications (MERRA) wind and solar reanalysis datasets, based on a given technology's power curve (McPherson, et al., 2017). CREST selects the capacity of wind and solar power to develop within each grid location based on the hourly wind and solar photovoltaic (PV) generation time series obtained through the GRETA platform. Modelled hourly wind or solar energy generation is the product of capacity installed within a grid cell and the capacity factor of the technology in that grid cell for that hour.

Wind and solar energy are treated as non-dispatchable resources within CREST, and the model does not account for potential errors in forecasting wind and solar generation. Since CREST does not currently include a requirement for reserve capacity, the model underestimates the dispatchable generation required to balance the variable wind and solar generation. Data concerning reserve requirements is available, and this limitation will be addressed in future iterations of CREST.

Model Opportunity #6: Future iterations of CREST will include consideration of balancing area reserve requirements in order to more accurately reflect system operations as well as capacity expansion in response to the development and operation of variable renewable generation.

Within balancing areas, CREST includes the cost associated with intra-balancing area wind and solar interconnections based on shortest distance to the existing electricity transmission network (Dolter & Rivers, 2018). Considering the recent significant declines in the costs of wind turbines and solar cells (Lazard, 2019), (NREL, 2019), transmission interconnection costs make up an increasing portion of overall resource development costs. Our review below (3.2v) of potential future hydroelectric renewals and greenfield development indicates that the nearest transmission network location is often unsuitable for project interconnection, or can only be made suitable with significant system upgrades. This suggests that the model potentially underestimates the costs of interconnecting wind and solar generation. Future iterations of CREST will verify and update the distance of wind and solar generation to suitable potential transmission interconnections, particularly in grid locations where the model develops significant wind and solar resources, and will also consider inclusion of substation development costs.

Model Opportunity #7: Future iterations of CREST will verify and update the distance of potential wind and solar generation to a suitable potential transmission interconnection, and also consider inclusion of substation development costs.

Levelized costs of energy from wind and solar generation have declined substantially over the past decade (Lazard, 2019), and are anticipated to continue to decline over the next decade (NREL, 2019). CREST makes use of the most up-to-date information available concerning capital, operations and maintenance costs for installation of wind and solar generation across Canada. The model does not yet account for potential declines in the future costs of energy from wind and solar resources, including those resulting from further declines in component or balance of system costs, further reductions in operations and maintenance costs, or future efficiency gains. This capability will be added to future iterations of CREST along with the potential to model variations in anticipated future cost declines.

Model Opportunity #8: Future iterations of CREST will include the potential to model anticipated future cost declines, particularly wind and solar capacity.

Almost all installed wind and solar capacity in Canada is developed by independent power producers and contracted to utilities or system operators through long-term contracts. Typically, these contracts are 20-25 years in length, though with improvements in technology and maintenance procedures recent contracts for both wind and utility-scale solar often extend to 30 years (NREL, 2019). With the earliest installed commercial wind turbines in Canada now approaching the end of their contracted service lives, and with many contracts for wind and solar set to expire in the coming decades, CREST models the recontracting of these facilities as integer (“yes” or “no”) decisions.

Redevelopment of an existing wind project may entail partial repowering, involving upgrades to the rotor diameters and major nacelle components of existing turbines, or full repowering where turbines towers, nacelles and rotors are entirely replaced (EIA, 2017). The cost of energy from repowered wind projects tends to be lower than existing projects as a result of increases in energy production (Villena-Ruiz, et al., 2018) and capacity factors (U.S. Department of Energy, 2018) arising from increased rotor diameters and efficiency improvements, as well as the utilization of existing infrastructure, including roads and substations. There has been limited study of this topic to date in Canada, though a recent review determined that repowering of wind turbines could be accomplished in British Columbia at a levelized energy cost 30% below that of comparable new installations (British Columbia Utilities Commission, 2017).

The earliest utility-scale solar facilities in Canada became operational in 2010, and repowering of these facilities is not anticipated to begin until closer to 2030 when their energy purchase agreements terminate. No reviews or studies of this topic in Canada were located, though it is reasonable to conclude that repowering of solar facilities will also involve cost savings compared to comparable new installations, resulting from utilization of existing road, foundation and transmission infrastructure.

Based on the available information, CREST assumes a 30% reduction in the levelized cost of energy from repowered wind and solar compared to similar greenfield development, reflected in the costs shown in Appendix C – Table 8.

The model presumes no differences in fixed operations and maintenance costs between repowered and greenfield wind and solar projects. These are preliminary assumptions, recognizing the need for more research in this area as wind and solar repowering becomes more common across Canada.

Model Enhancement #2: CREST is configured to allow for potential repowering of contracted wind and solar resources at costs lower than comparable greenfield generation.

Model Limitation #8: We assumed a 30% reduction in the cost of energy from repowered wind and solar resources compared to similar greenfield resources, based on values from the literature. The potential for error in this assumption could be reduced through additional research in this area as wind and solar repowering becomes more common across Canada.

v. Hydroelectric

Characterization

Existing hydroelectric generation in Canada consists of more than 83,000 MW of installed capacity at over 500 locations, producing more energy than any other type of generation in Canada. Due to both seasonal and regional variations in hydroelectric resources nation-wide, attention to both temporal and spatial considerations is required to characterize hydroelectric facility operations.

CREST characterizes hydroelectric generation temporally on the basis of the duration of its generation and storage potential into four categories: run-of-river, daily storage, monthly storage, and pumped storage. Run-of-river hydroelectric is presumed to be non-dispatchable, to have no ability to store water and to produce at an hourly generation that varies according to average monthly historical output. Daily storage hydroelectric is presumed to have live storage[4] potential that allows for flexible dispatch up to 24 hours, with production constrained such that total electricity generated does not exceed the average hourly production multiplied by 24 hours. Monthly storage hydroelectric is presumed to have live storage potential that allows for flexible dispatch on the order of weeks to months, ramping up production on a daily and seasonal basis as well as storing water during periods of low demand. Monthly storage generation is constrained such that total monthly production does not exceed the average hourly production multiplied by the number of hours in the month. We model pumped storage using three main constraints: the first limits the maximum energy that can be stored; the second limits the maximum

[4] *live storage* refers to the volume of water available in the reservoir(s) upstream of the facility that is above the minimum supply level and below the maximum operating level

generation to the available capacity; and the third calculates the stored energy according to the hourly efficiency of pumping in and turbining out within each hour.

The current iteration of CREST expands upon the previous allocation of hydroelectric resources into these categories based primarily on reservoir size, and also disaggregates the categorization by balancing area. In addition to reservoir size, other factors considered in allocating facilities into hydroelectric categories includes: utility, operator and owner categorization; hourly generation data; the presence, storage, and number of upstream reservoirs or other forms of flow regulation (e.g. weirs); and categorization of upstream and downstream facilities.

Model Enhancement #3: CREST distinguishes the proportion of the installed capacity of run-of-river, daily storage and monthly storage generation within each balancing area.

Model Enhancement #4: CREST improves upon the allocation of existing facilities into hydroelectric storage categories on the basis of several factors in addition to reservoir size.

The utilities and system operators publicly use a binary categorization system for hydroelectric facilities such as “run-of-river” or “reservoir” (Hydro Québec, 2019) and “non-storage” or “storage”, (BC Hydro, 2019). There are limitations to this approach, since “run-of-river” is often used to refer to facilities that have reservoirs and that have considerable daily storage potential. A study of wind integration potential in Nova Scotia found that essentially all the installed hydroelectric generation within that province, much of which is small-scale and often referred to as “run-of-river”, provides or could provide dependable capacity at periods of peak demand (Hatch, 2008).

For all “run of river” and “non-storage” hydroelectric facilities with more than 10 MW of installed capacity, we sought additional evidence to confirm or disconfirm the availability of daily storage potential, reallocating facilities accordingly between categories. Our research revealed that as currently defined “daily storage” includes two distinct types of hydroelectric generation: facilities capable of 10-16 hours of flexible operation as a result of reservoir live storage or by taking advantage of upstream flow regulation, and that also have minimum flow requirements (i.e. operations are never 0 MW/hour other than for maintenance); and those facilities with sufficient live storage and installed capacity to be operated exclusively as peaking resources for up to 4 hours at a time, and do not have hourly downstream flow requirements (IESO, 2019a), (AESO, 2018). CREST does not currently distinguish between these two types of facilities, though their respective hourly operations are quite different.

Model Opportunity #9: Future iterations of CREST will include the consideration of “hourly peaking” hydroelectric facilities as distinct from “daily storage” facilities.

The availability of historical hourly hydroelectric generation data (Table 1) assists in the characterization of hydroelectric facilities in several respects by: revealing those facilities that operate exclusively for daily peaking purposes; indicating minimum and maximum flows through the facilities (particularly where multiple years of data are available); and providing an indication of ramping potential at each facility and across the hydroelectric fleet. For those jurisdictions and for those generating stations for which hourly generation data is available, this data is used to more appropriately categorize hydroelectric facilities. The public availability of historical hourly generation data for hydroelectric facilities across Canada would allow for more precise characterization of hydroelectric resources within CREST.

Model Limitation #9: The public availability of historical hourly generation data for hydroelectric facilities across Canada would allow for more precise characterization of hydroelectric resources within CREST.

A conservative approach is taken to categorizing facilities initially designated by the utilities as “reservoir” or “storage” facilities’ with the default categorization being “daily storage”. Available flow and level data, reservoir and watershed mapping, watershed management plans and prior studies of these hydroelectric facilities were reviewed to confirm or disconfirm this categorization before identifying facilities as “monthly storage”.

The location of a given hydroelectric facility within a cascading system of facilities on the same watershed is also considered in categorizing facilities. Commonly, the hydroelectric potential of a given watershed is developed with an upstream reservoir having a large live storage volume, and one or more downstream reservoirs with lower volumes of live storage, whose generating facilities also benefit from the upstream flow regulation. This general design characterizes developments on many rivers within Canada, including the Peace, Columbia, Nelson, La Grande, Outardes and Churchill, among others. The uppermost hydroelectric facilities on these kinds of systems are generally categorized as “monthly storage” due to their considerable live storage. The categorization of the downstream facilities depends on many factors beyond the scope of this initial research, including: synchronization of facilities, live storage in the downstream facility reservoirs, local inflows above each generating facility, and downstream flow requirements. As a result, some of these downstream facilities are categorized as “daily storage” and others as “monthly storage”.

Model Opportunity #10: Future iterations of CREST will improve upon the characterization of facilities located downstream of existing large upstream reservoirs in terms of facility synchronization, inflow quantification and downstream flow requirements.

Based on our review to date, the initial list of proposed monthly storage facilities is shown in Appendix C – Table 11. In terms of system water balance characterization, CREST does not currently establish minimum and maximum reservoir levels or storage volumes. Additional review of available reservoir data sets and Water Survey of Canada flow and level data may support this degree of characterization in subsequent model iterations. CREST also does not currently disaggregate instream flow requirements by facility, assuming that all hydroelectric facilities have minimum flow requirements of 10% of balancing area installed capacity.

Model Opportunity #11: Pursuant to a review of hourly facility generation data and permitting requirements respecting minimum downstream flows, future iterations of CREST will improve upon the estimates of hourly minimum flow requirements for hydroelectric generation.

<u>New hydroelectric generation</u>

In addition to substantial existing installed hydroelectric generation, Canada has significant technically feasible additional hydroelectric development potential (BC Hydro, 2013b) (Hatch Ltd., 2013) (Hatch Ltd., 2010). The inclusion within CREST of the capability to develop new hydroelectric resources marks a significant enhancement to the model. These potential new hydroelectric facilities include hydroelectric renewals, pumped storage and greenfield projects as summarized in Table 2.

Information concerning potential new hydroelectric generation is gathered primarily from utility and system operator reports, regulatory filings, proponent documentation and government reports. CREST models the costs of potential future generation in terms of annualized project capital costs, fixed and variable annual operations costs, and fuel costs, as indicated in Appendix C – Table 8. In the case of new hydroelectric generation these costs are developed on a facility by facility basis considering publicly available capital costs, operating costs, additional installed capacity, construction duration, and development times.

Table 2: Hydroelectric renewals, pumped storage and greenfield projects modeled in CREST

Balancing Area	Renewal Projects	Additional Installed Capacity (MW)	Development Time (Years)
British Columbia	Alouette Redevelopment	21	6
	Ash River Additional Unit	9	6
	Elko Redevelopment	21	6
	Falls River Redevelopment	24	6
	GMS Units 1-5 Capacity Increase	100	6
	Ladore Additional Unit	9	6
	Lajoie Additional Unit	30	6
	Puntledge Additional Unit	10	6
	Revelstoke 6	488	8
	Seton Unit Upgrade	2	6
	Seven Mile Turbine Upgrades	48	6
	Shushwap Refurbishment	3	6
	Wahleach Additional Units	14	6
Alberta	Brazeau Capacity Addition	170	6
Manitoba	Kelsey Additional Units	178	6
Quebec	Sainte-Margeurite-3 Unit 3	440	8
New Brunswick	Grand Falls_05	100	6
Newfoundland	Bay Despoir_08	154	6
	Cat Arm_03	68	6
Sources:	(AESO, 2017); (British Columbia Utilities Commission, 2017); (Manitoba Hydro, 2007); (Hydro Québec, 2009); (NB Power, 2017); (Newfoundland and Labrador Hydro, 2018)		
Balancing Area	**Pumped Storage Projects**	**Additional Installed Capacity (MW)**	**Development Time (Years)**
British Columbia	37 Pumped Storage Sites	500	8-9
	208 Pumped Storage Sites	1000	8-9
	Mica Pumped Storage	500	8
Alberta	Brazeau Pumped Storage	900	8
	Canyon Creek	75	8
New Brunswick	Grand Falls Pumped Storage	100	6
Ontario (South)	Marmora Pumped Storage	400	8
	Meaford Pumped Storage	1000	8
Sources:	(Knight Piésold Ltd., 2010); (BC Hydro, 2013c); (TransAlta Corporation, 2017); (Turning Point Generation, 2017); (NB Power, 2017); (Northland Power, 2019); (TC Energy, 2019)		
Balancing Area	**Greenfield Projects**	**Additional Installed Capacity (MW)**	**Development Time (Years)**
British Columbia	14 Potential Sites	8,008	8-20
Alberta	Amisk Hydro Development	370	13
	Slave River Hydro Development	1,100	15
Saskatchewan	Tazi Twe	50	6
Manitoba	11 Potential Sites	4,415	15-20
Ontario (North)	37 Potential Sites	5593	11-13
Québec (North)	Magpie Complex	850	15
	Petit Mécantina	1200	15
	Tabaret	130	8
New Brunswick	High Narrows	40	6
Labrador	10 Potential Sites	4238	11-17
Newfoundland	5 Potential Sites	143	5
Sources:	(BC Hydro, 2008); (AHP Development Corporation, 2019); (AESO, 2017); (Tazi Twé Hydroelectric Project, 2014); (Manitoba Hydro, 2013); (Hatch Ltd., 2013); (Hydro Québec, 2009); (Nalcor Energy, 2009); (Newfoundland and Labrador Hydro, 2018); (NLH, 1979a); (NLH, 1979b)		

Since much of the technically feasible undeveloped hydroelectric generation is remote from the existing transmission system, the cost of interconnecting transmission is material to overall development costs. Our review of potential future hydroelectric renewals, pumped storage and greenfield development – particularly where additional installed capacity is substantial – indicates that the nearest transmission network location is often unsuitable for project interconnection due to insufficient voltage and other factors, and can only be made suitable with significant system upgrades.

To address this issue, in estimating the length of interconnecting transmission we use a "distance to market transmission", reflecting the likely length of transmission required for the facility to interconnect at the appropriate voltage to access the market. Where hydroelectric renewals do not involve significant capacity increases, the distance to market transmission is presumed to be zero, since no material transmission upgrades are anticipated, other than potentially substation upgrades.

Considering the limited electricity resources currently developed in the Canadian territories, and to limit computational requirements, only locations south of 60˚ latitude are currently considered. The potential to expand the model's spatial coverage north of 60˚ latitude is under consideration since it would allow for future modelling of additional scenarios including: interconnecting the Yukon, Northwest Territories and Nunavut to support further decarbonization and load balancing within those smaller-scale systems (BBA Inc., 2015), (Yukon Energy, 2017), and evaluating the potential to develop northern hydroelectric resources (Government of the Northwest Territories, 2011).

Model Opportunity #12: Pending availability of suitable hydroelectric and system data, CREST's spatial coverage could be expanded to include coverage north of 60˚ latitude to evaluate the potential for interconnection and development of northern hydroelectric resources.

Recontracting existing hydroelectric generation

A considerable quantity of hydroelectric capacity in Canada is owned and operated by independent power producers under long-term contract to utilities and system operators. These contracts are typically on the order of 40 years, many are renewed upon termination, and CREST models the recontracting of these facilities.

Unlike redevelopment of an existing wind or solar facility, where major replacement of components and equipment is required, hydroelectric repowering typically has much lower refurbishment costs since most of the civil works can be reused (BC Hydro, 2017). The cost of energy from repowered hydroelectric projects tends to be governed by the utility's need for energy and the cost and availability of energy from the market, or from alternative new supply resources. Average annual energy prices in most jurisdictions across North America, and from which most Canadian utilities or system operators would have access, have averaged on the order of \$30 to \$35/MWh in the past several years (Potomac Economics, 2019a), (Potomac Economics, 2019b). Wind generation is the lowest-cost competitive low-carbon alternative to repowering hydroelectric facilities in most regions within Canada, and depending on location produces energy at a cost between \$40/MWh and \$60/MWh (AESO, 2018), (Nova Scotia Power Inc., 2019). Based on the available information, CREST assumes a levelized energy cost of \$40/MWh for recontracted hydroelectric generation, which results in the annualized capital costs and operating costs shown in Appendix C – Table 8.

The model presumes somewhat higher fixed operations and maintenance costs for repowered hydroelectric compared to existing projects, reflecting the lower average installed capacity of repowered facilities and higher fixed operations and maintenance costs per unit of installed capacity. As is the case for wind and solar repowering, these are preliminary estimates recognizing the need for more research as recontracting of hydroelectric facilities becomes more common across Canada in the coming years.

Model Enhancement #5: CREST is configured to allow for potential repowering of contracted hydro resources at costs considerably lower than comparable greenfield generation.

Model Limitation #10: Based on available information, CREST includes recontracted hydroelectric generation at a levelized cost of energy of $40/MWh. Potential for error in this assumption could be reduced through additional research as recontracting of hydroelectric facilities becomes more common across Canada in the coming decades.

vi. Transmission

A key modeling strength of CREST is the comparative evaluation of the desirability of investing in transmission versus energy generation and storage technologies, including pumped storage and reservoir storage, which are substitute options for balancing the intermittency of variable renewables. This is particularly salient in the Canadian context, where hydroelectric systems dominate the electricity supply in four Canadian provinces (BC, Manitoba, Québec, Newfoundland and Labrador) directly adjacent to provinces in which substantial electricity system decarbonization is still required (Alberta, Saskatchewan, New Brunswick and Nova Scotia).

Information concerning the location of existing transmission lines in Canada is drawn from DMTI (2019), and from utility network maps. Since CREST explicitly models the transmission of electricity between balancing areas, the locations and transfer capacities of existing interprovincial interties are obtained from utility and reliability coordinator reports and regulatory filings. These transfer capacities are adjusted to reflect reservations of transmission capacity in relation to long-term contracts for purchase and sale of firm (non-interruptible) capacity between provinces, as summarized in Table 9.

We reviewed the cost information contained in Dolter & Rivers (2018) respecting fixed transmission loss of 2% and variable transmission loss of 0.003% per km for electricity transmitted between balancing areas, as well as intra-balancing area transmission costs of $557/MW/km/year and inter-balancing area costs of $184/MW/km/year (GE Energy Consulting, 2016). Based on our review, these costs adequately reflect average transmission losses and costs across Canada. However, we note substantial variations in losses and costs between and within balancing areas, typically ranging by a factor of three depending on terrain, and 5 to 15 times as costly for submarine transmission, as reflected in Appendix C –

Table 12.

Based on this information, and a review of transmission costs relation to the recently constructed Labrador Island Transmission Link and Maritime Link, to account for the substantially higher cost of submarine transmission we multiply the submarine distance between balancing areas by a factor of six. Adjustments to reflect differences in intra-balancing and inter-balancing costs are planned for subsequent iterations of CREST, in conjunction with the addition of more balancing areas.

2.3 Summary

CREST is a capacity expansion model, and specifically a mixed integer linear program optimization model, that minimizes the total investment and operating costs of a given electricity system by making investments in generation and transmission technologies and optimizing their hourly dispatch over the course of a year.

Developing the model for the current analysis, we made several adjustments to the model inputs, constraints and operations in order to enhance its performance. The following table summarizes these enhancements. Model limitations and model opportunities identified in this section of the report are summarized and discussed in section 5 in the context of policy implications.

Table 3: Summary of model enhancements in the current iteration of CREST

Item Number	Description
Model Enhancement #1:	CREST is reconfigured as a mixed integer linear program optimization model.
Model Enhancement #2:	CREST is configured to allow for potential repowering of contracted wind and solar resources at costs lower than comparable greenfield generation.
Model Enhancement #3:	CREST distinguishes the proportion of the installed capacity of run-of-river, daily storage and monthly storage hydroelectric generation within each balancing area.
Model Enhancement #4:	CREST improves upon the allocation of existing facilities into hydroelectric storage categories on the basis of several factors in addition to reservoir size.
Model Enhancement #5:	CREST is configured to allow for potential repowering of contracted hydro resources at costs considerably lower than comparable greenfield generation.

3 Results

3.1 Scope

CREST evaluates competing scenarios for decarbonization of the electricity grid considering different technological and policy options, including the imposition of carbon prices, as summarized in Appendix C – Table 13. Here, we present, explore and discuss the results of our initial analysis in terms of the changes to the Canadian electricity system in the target years 2030 and 2050 in response to a carbon pricing signal. Our results focus on the following technological, environmental, and economic outputs:

- Changes to installed generation capacity in Canadian and in each balancing area
- Generation capacity retirements and installations
- New transmission infrastructure
- System-wide carbon (CO_2e) emissions
- System-wide annual system costs

3.2 Presentation and interpretation

i. Installed capacity

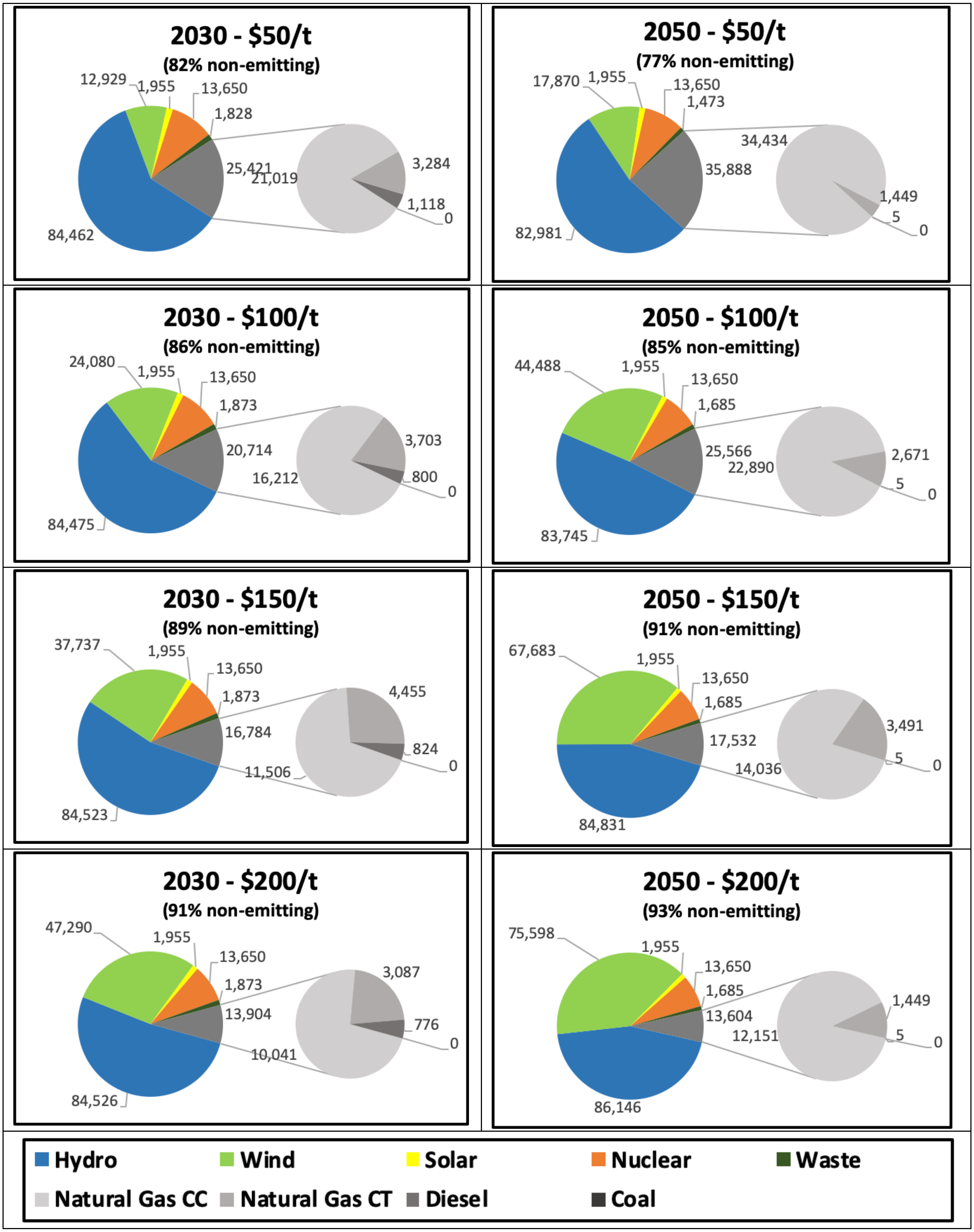
The modeled results for Canada's installed capacity considering four carbon price signals (50 $/tonne, 100 $/tonne, 150 $/tonne, 200 $/tonne) are illustrated in Figure 3 for both 2030 and 2050. These results illustrate several key trends:

Non-emitting grid: In response to a rising carbon price, the Canadian electricity grid becomes increasingly non-emitting. From Figure 1, the existing proportion of 24% installed emitting capacity is reduced under all pricing scenarios, except a $50/t carbon price in 2050, suggesting that the carbon price will need to increase beyond current policy to prevent backsliding towards greater installed emitting generation within the Canadian electricity system. A carbon price of at least $150/t is required to achieve the First Ministers' commitment to a clean electric future where 90% of Canada's electricity comes from non-emitting sources by 2030 (Government of Canada, 2018).

Policy Implication #1: The carbon price will need to increase beyond current policy to prevent backsliding towards greater installed emitting generation within the Canadian electricity system.

Policy Implication #2: A carbon price of at least $150/t is required to achieve the First Ministers' commitment to a clean electric future where 90% of Canada's electricity comes from non-emitting sources by 2030.

Figure 3: Canadian installed capacity in 2030 and 2050 in response to carbon tax (MW)



Coal: At a carbon price of $50/t or higher, all coal is removed from the Canadian electricity grid by 2030. It is important to note that the model does not currently account for costs that may result from stranding investments where resources are retired before the end of their economic lives. Inclusion of stranded asset costs would likely alter the most cost-effective retirement dates for coal, and potentially also natural gas and diesel.

Model Opportunity #13: Future iterations of CREST could include the costs of stranded assets that are potentially incurred upon early retirement of generating facilities.

Natural gas: The total installed capacity of natural gas combined cycle and combustion turbines is reduced when carbon prices exceed $100/t. However, significant quantities remain in place even under a $200/t carbon price. Natural gas is currently very low cost and has a lower emissions intensity compared to other fossil fuel generation (refer to Appendix C – Table 8). This finding is consistent with that of Dolter & Rivers (2018), which found that a cost approaching $500/t is required to remove all fossil fuel generation from the Canadian electricity system.

Diesel: For the 2050 target year, diesel generation is essentially retired from the grid under all carbon price scenarios. The situation is more nuanced for the 2030 target year, where diesel generation is halved in the $50/t scenario with only modest further reductions at high carbon prices. The diesel category includes oil and diesel generation located exclusively in the Atlantic provinces, and results suggest that this resource will continue to play a balancing role for the coming decade.

Waste: This category consists largely of contracted biomass facilities as well as some municipal solid waste and biogas facilities. Though utilities do not typically presume 100% recontracting of biomass generation (BC Hydro, 2013a), information was unavailable regarding which facilities might or might not be recontracted, and so the current model assumption is that all facilities will continue operating indefinitely. The model also currently assumes a lifecycle emissions intensity of 0 CO_2e/t for this generator type, which is inconsistent with recent findings (Beagle & Belmont, 2019), and reviews (Muench & Guenther, 2013). Though the total installed capacity of biomass, biogas and municipal solid waste resources is relatively modest, the characterization of this resource can be improved as part of future model development.

Model Opportunity #14: Future iterations of CREST will improve upon the characterization of biomass generation recontracting and CO_2e emissions intensity.

Nuclear: Nuclear refurbishment costs are not imposed in the model inputs, since the decisions to refurbish have already been taken in Ontario and New Brunswick. Given their low emissions, existing nuclear facilities continue to operate into the respective target years of 2030 and 2050. The high cost of nuclear generation inhibits the development of any new nuclear facilities. The potential need for new nuclear generation could arise at higher demand levels commensurate with increased low-carbon electrification. Policy direction regarding additional nuclear generation needs to consider scenarios for future demand under low-carbon electrification as well as the availability of lower-cost alternatives.

Policy Implication #3: Policy direction regarding additional nuclear generation needs to consider scenarios for future demand under low-carbon electrification as well as the availability of lower-cost alternatives.

Solar: All existing solar generation is recontracted, suggesting that the estimated cost to recontract solar is competitive with new wind resources. The current cost of new solar generation prohibits the development of any new resources in Canada, though costs continue to decline and further substantial declines are widely anticipated (Lazard, 2019), (NREL, 2019). Recent competitive procurements for renewable resources in Canada awarded contracts to lower-cost wind resources (AESO, 2018), or held separate procurements for solar (Saskpower, 2019), acknowledging the cost of energy advantage wind retains over solar. Most recent analyses anticipate this advantage will continue to narrow in the coming decade with a crossover occurring around 2030 depending on relative costs of wind and solar generation specific to location.

Wind: As a result of its low capital cost, the high quality wind resource, and proximity to load, particularly locations near or within balancing areas with high-emitting generation (i.e. Alberta, Saskatchewan, New Brunswick and Nova Scotia), wind is the preferred low-carbon energy resource. Under a $50/t carbon price, total installed wind capacity in Canada declines modestly in 2030: not all contracted wind is immediately recontracted due to low forecasted load growth in some provinces (e.g. Ontario). Wind installed capacity increases dramatically in high carbon price scenarios, rising in the $200/t scenario from 13 GW in 2018 to over 47 GW in 2030 and to over 75 GW in 2050.

Hydroelectric: Hydroelectric installed capacity decreases marginally under all carbon tax scenarios in both 2030 and 2050. Hydroelectric assets may or may not be recontracted, allowing for some generation reductions upon contract termination. The decommissioning of hydro is driven by two factors: (1) its assumed levelized cost is $40/MWh, which is comparable to that of wind; (2) and the agglomeration of recontracted hydro by balancing area makes it “lumpier”, which deters recontracting all available hydro. Future iterations of CREST will address this limitation by treating all potential recontracted hydroelectric facilities as individual projects. The lack of new hydroelectric installed capacity may reflect the remoteness of new hydro locations, which are costly to access due to the need for new-build long-distance high-voltage transmission. Further, most new hydroelectric potential resides within jurisdictions that are already largely decarbonized.

Model Limitation #11: The agglomeration of recontracted hydro by balancing area may inhibit hydroelectric recontracting. Future iterations of CREST will address this limitation by treating all potential recontracted hydroelectric facilities as individual projects.

ii. Capacity retirements and additions

The changes in installed capacity that occur as a result of carbon pricing are illustrated in terms of retirements in Figure 4 and additions in Figure 5. The effect of these changes on the generation mix is shown in Figure 6. These results illustrate several key trends in relation to growth and retirement of specific generation types:

Accelerating coal retirements: Under a policy where carbon prices rise quickly to $50/tonne by 2030, more than 6,000 MW of coal is retired, including all coal scheduled to retire after 2030. Carbon pricing plays a role in advancing coal retirements.

Policy Implication #4: Under a policy where carbon prices rise quickly to $50/tonne by 2030, more than 6,000 MW of coal is retired, including all coal scheduled to retire after 2030. Carbon pricing plays a role in advancing coal retirements.

Figure 4: Thermal generation retirements in 2030 and 2050 (MW)

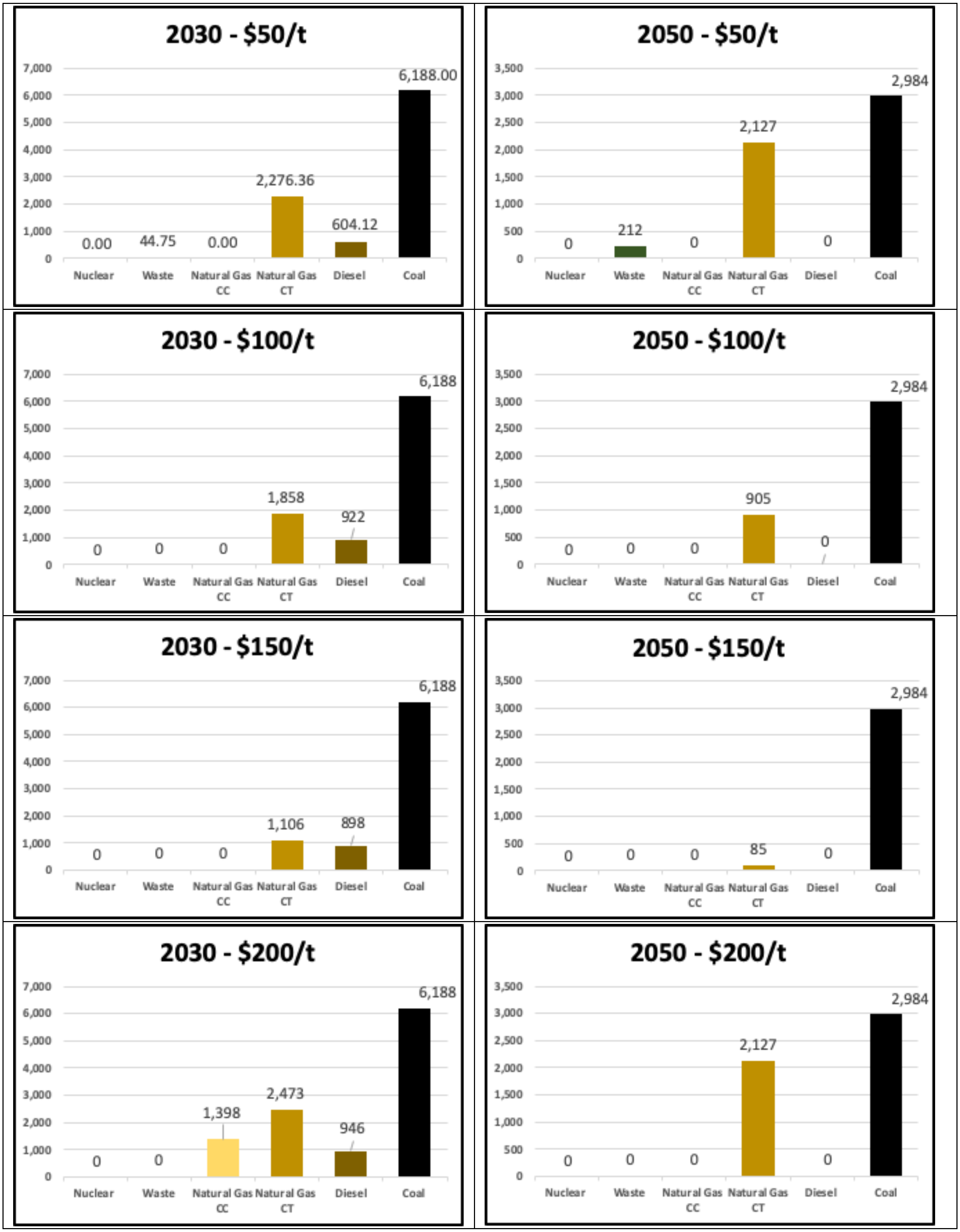


Figure 5: Generation additions in 2030 and 2050 (MW)

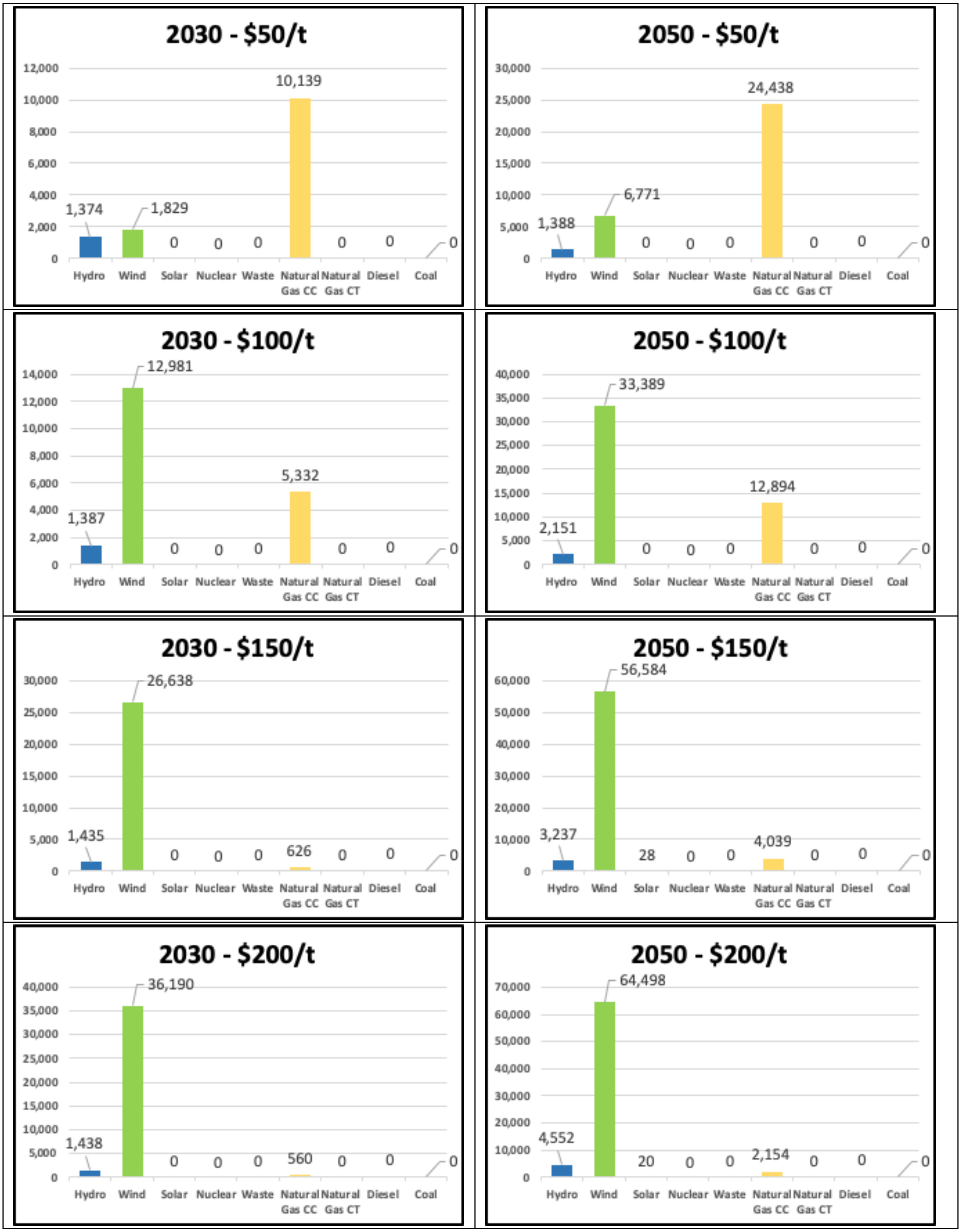
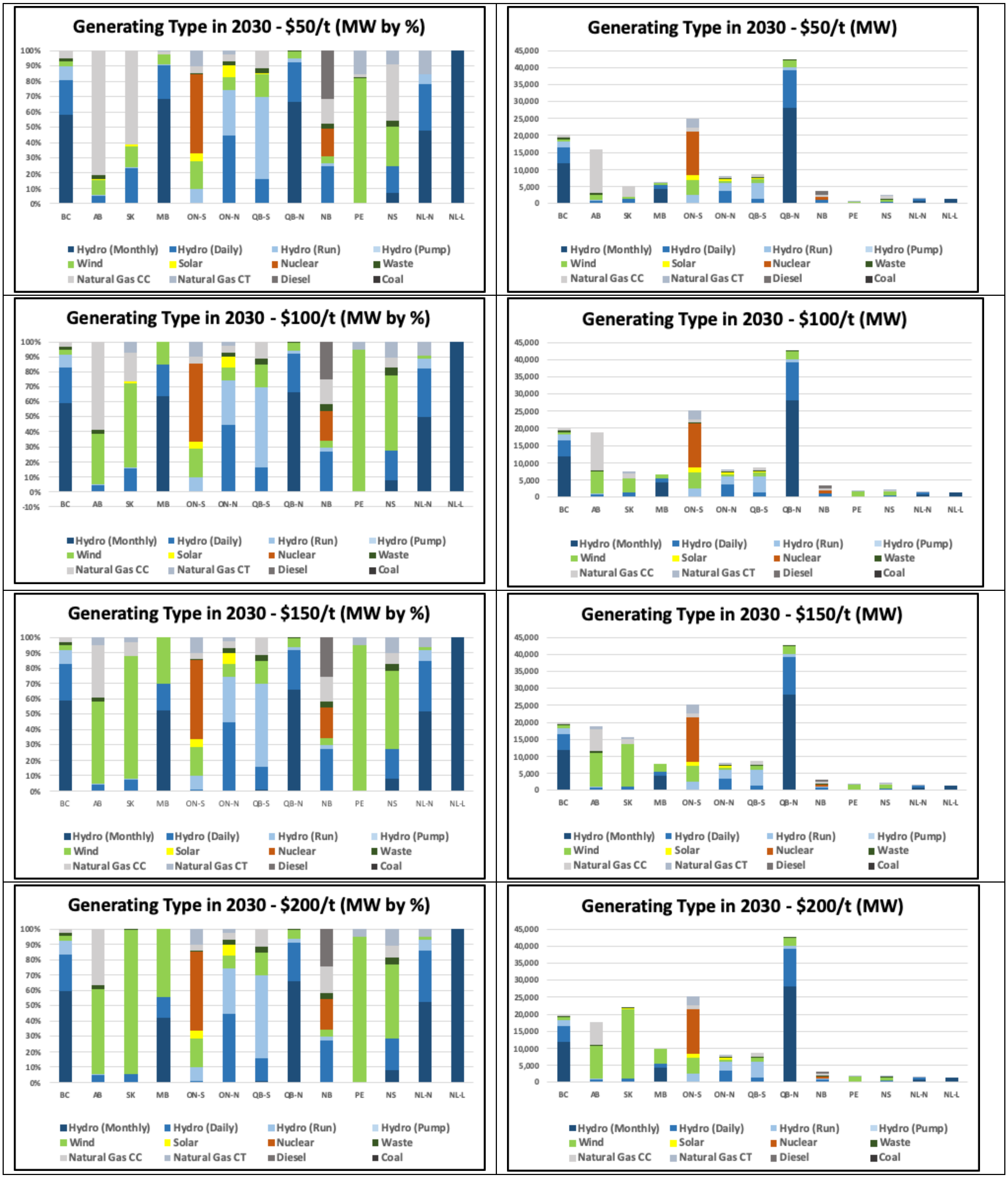


Figure 6: Balancing area installed capacity in 2030



Natural gas as a balancing resource: Figure 5 illustrates the changing role of natural gas under a more aggressive carbon pricing policy. In both 2030 and 2050, with a $50/t carbon price, natural gas is deployed to meet increasing demand and replace coal retirements. At a $100/t carbon price, more wind is developed, less natural gas combined cycle is developed and less natural gas peaking capacity is retired (Figure 4), as the latter becomes the favoured resource for balancing large wind deployments. At a $150/t carbon price, almost no new combined cycle natural gas is built in 2030. In 2050, a carbon tax of $150/t reduces the installed capacity of new natural gas to 4,000 MW, compared to 24,000 MW in the $50/t scenario, a substantial reduction. Finally, with a $200/t carbon price, some existing combined cycle gas is retired along with larger quantities of natural gas peakers. These results have significant implications for policy makers: at the higher carbon prices necessary to achieve deep decarbonization, significant quantities of natural gas must be retired, and very little new natural gas capacity can be developed.

Policy Implication #5: At the higher carbon prices necessary to achieve deep decarbonization, significant quantities of natural gas must be retired, and very little new natural gas capacity can be developed.

Hydro as a balancing resource: Complimentary to the declining role of natural gas, hydroelectric capacity increases with the carbon price in 2050, partially assuming the role of natural gas as the balancing resource for wind. For that year, the hydroelectric additions are approximately three times larger in the $200/t scenario (4,500 MW) than in the 50/t scenario (1,400 MW), due to both hydroelectric recontracting and new build. This phenomenon is not seen in the 2030 scenario, due to the long lead times for greenfield hydroelectric.

Wind as a low-cost resource, strategically located: As shown in Figure 6, large quantities of wind in the southern prairies (especially Saskatchewan) and Prince Edward Island are developed by 2030. As the carbon price increases to $200/t, installed wind capacity in Saskatchewan rises to 20 GW in 2030 and 29 GW in 2050. Such large quantities of new wind capacity may not be sustainable in terms of industry development potential, land-use limitations or local social acceptability (Palmer-Wilson, et al., 2019). For example, Saskpower is currently developing 200 MW of new wind capacity every two years to 2030 (Saskpower, 2017), whereas these results contemplate up to 2,000 MW annually in the near term (to 2030) and 1,000 MW annually in the long term (2030-2050). For context, the State of Iowa, with a suitable land area for wind development less than half that of Saskatchewan, installed about 5 GW of wind since 2010 while Texas, with a similar land area for development, installed 25 GW of wind since 2000 (EIA, 2019e). The modeled wind build-out in Saskatchewan, though large, is not without precedent.

iii. The role of hydroelectric renewals, pumped storage and greenfield hydroelectric

We postulated that hydroelectric renewals and pumped storage hydroelectric could contribute meaningfully to Canada's 2030 emissions reduction targets, as a result of their shorter development times when compared to large-scale greenfield hydroelectric development. We identified 19 potential hydroelectric renewal sites and more than 250 pumped storage sites, most of which are in British Columbia. Table 4 summarizes the hydroelectric renewals and whether they are developed by 2030 under each carbon price scenario. In general, the large renewal sites are developed by 2030 under all carbon price scenarios, while some small-scale renewal sites are developed in the higher carbon price scenarios. The overall contribution of hydroelectric renewals approaches 1,500 MW.

Table 4: Hydroelectric renewals modeled in CREST – developments by 2030

Balancing Area	Project	Additional Capacity (MW)	Developed by 2030 ($50/t)	Developed by 2030 ($100/t)	Developed by 2030 ($150/t)	Developed by 2030 ($200/t)
British Columbia	Alouette Redevelopment	21				
	Ash River Additional Unit	9				
	Elko Redevelopment	21				
	Falls River Redevelopment	24				
	GMS Units 1-5 Capacity Increase	100	100	100	100	100
	Ladore Additional Unit	9				
	Lajoie Additional Unit	30		30	30	30
	Puntledge Additional Unit	10				
	Revelstoke 6	488	488	488	488	488
	Seton Unit Upgrade	2				
	Seven Mile Turbine Upgrades	48			48	48
	Shushwap Refurbishment	3				3
	Wahleach Additional Units	14	14	14	14	14
Alberta	Brazeau Capacity Addition	170				
Manitoba	Kelsey Additional Units	178	178	178	178	178
Quebec	Sainte-Margeurite-3 Unit 3	440	440	440	440	440
New Brunswick	Grand Falls_05	100				
Newfoundland	Bay Despoir_08	154	154	154	154	154
Newfoundland	Cat Arm_03	68				
	TOTALS		**1374**	**1387**	**1435**	**1438**
Sources:	(AESO, 2017); (British Columbia Utilities Commission, 2017); (Manitoba Hydro, 2007); (Hydro Québec, 2009); (NB Power, 2017); (Newfoundland and Labrador Hydro, 2018)					

Recently developed large-scale hydroelectric projects have incurred substantial cost overruns (British Columbia Utilities Commission, 2017), (Boston Consulting Group, Manitoba Hydro, 2016), (Muskrat Falls Corporation, Labrador Transmission Corporation, 2018), imposed significant environmental effects (Joint Review Panel, 2011), (Joint Review Panel, 2014), and required on the order of 20 years from conception to commissioning. The potential to develop hydroelectric renewals offers a policy alternative for reducing GHG emissions on the Canadian electricity grid with reduced environmental effects, competitive costs and shorter development timeframes compared to greenfield hydroelectric development.

Policy Implication #6: The potential to develop hydroelectric renewals offers a policy alternative for reducing GHG emissions grid with reduced environmental effects, competitive costs and shorter development timeframes compared to greenfield hydroelectric development.

Despite over 250 possible sites, including within four different provinces, no pumped storage capacity is developed by 2030 or 2050. Of the 85 possible greenfield hydroelectric projects, only a single facility is developed by 2050 in the $200/t carbon price: the Conawapa Project on the Nelson River in Manitoba. This project was reviewed five years ago by the Manitoba Public Utilities Board, which determined that electricity demand in Manitoba did not merit moving forward with the project in the foreseeable future (Manitoba Hydro Public Utilities Board, 2014). High pumped storage and hydroelectric greenfield capital costs, remoteness (leading to costly transmission development), as well as the assumption of mid-load growth in demand influence these results.

Costs for hydroelectric renewals, pumped storage and greenfield hydroelectric for this analysis are derived from utility reports and regulatory filings, initially developed to a Class 3 (-20% to +30%), Class

4 (-30% to +50%) or Class 5 (-50% to +100%) estimate, as defined by the Association for the Advancement of Cost Engineering (AACE International, 2019). These costs are adjusted to current (2018) dollars and adjusted as appropriate for interest during construction, project development costs, and capital overhead based on the financial parameters indicated in Appendix C – Table 8.

Use of different assumptions and financial parameters would lead to different results. Future iterations of CREST will consider sensitivity analyses on the costs of hydroelectric and other generation and transmission resources to determine the robustness of the findings under differing cost assumptions.

Model Opportunity #15: Future iterations of CREST will consider sensitivity analyses on the costs of hydroelectric and other generation and transmission resources to determine the robustness of the findings under differing cost assumptions.

iv. Transmission

The transmission additions for 2030 and 2050 are shown in Figure 7. These results illustrate several key findings:

Transmission services wind: Much of the new-build wind capacity is situated in southern Saskatchewan and Prince Edward Island, which necessitates considerable transmission expansion to access balancing resources, as well as markets for surplus energy.

Saskatchewan to Alberta: The provincial boundary between Alberta and Saskatchewan defines the boundary between the Western Interconnection and Eastern Interconnection. These two systems are asynchronous, and an HVDC intertie is not considered here. While our preliminary results suggest transmission additions of more than 7 GW by 2030 and 11 GW by 2050, we do not believe this to be technically or socially feasible. Once the model limitations identified within this report are addressed, we believe this result will change.

Alberta to British Columbia: The additional transmission capacity between Alberta and British Columbia likely results from the large volume of low-cost intermittent wind energy introduced into Alberta by the introduced Saskatchewan to Alberta interconnection addition. This finding may also change once the model limitations identified within this report are addressed.

Manitoba to Saskatchewan: Manitoba has considerable hydroelectric balancing resources as well as high-quality wind resources, both of which are developed for export to Saskatchewan where they displace existing thermal generation. This result is consistent with recent explorations by Manitoba Hydro and Saskpower to increase the intertie capacity between their systems by 1000 MW by 2030 (Manitoba Hydro, Saskpower, 2019). Correlations between these initial results and utility plans demonstrate the potential for the model to be further developed as a tool for simulating capacity expansion opportunities under active consideration.

Policy Implication #7: Correlations between these initial results and utility plans demonstrates the potential for the model to be further developed as a tool to simulate capacity expansion opportunities under active consideration.

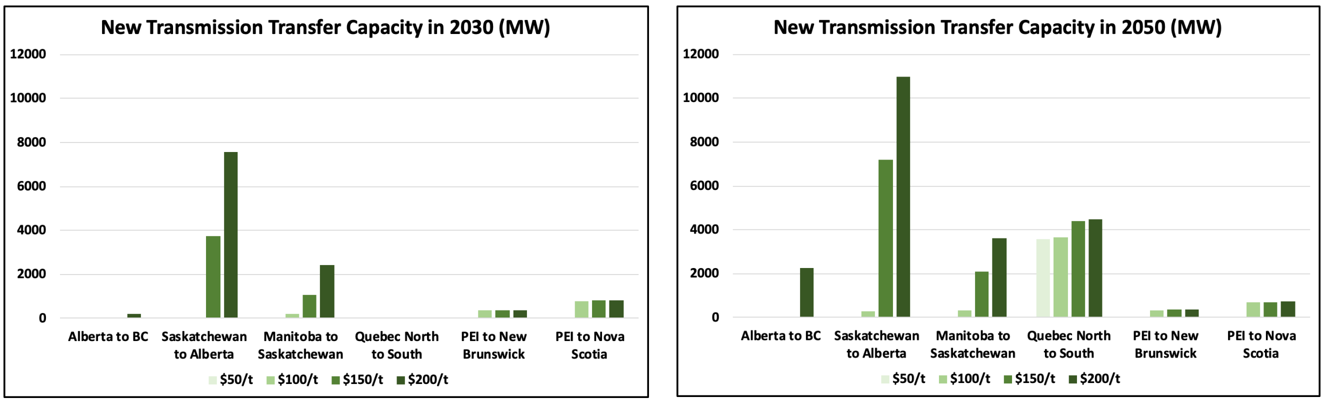
Quebec North to Quebec South: Additional wind and hydroelectric resources are developed in northern Quebec under most carbon price scenarios. Nonetheless, the 4,000 MW of additional transfer capacity suggested in our results is likely not justified, and will be reviewed in conjunction with reconsidering Québec's balancing area boundaries in subsequent model iterations.

PEI transmission: PEI has a very high-quality wind resource that has resulted in a total installed wind capacity in excess of 200 MW to date, with additions in the pipeline. Our results suggest an additional

1,800 MW of wind capacity, and such an extensive build-out may not be technically feasible or socially acceptable, as it would represent a very high turbine density. Future model iterations will revisit the maximum wind development densities contemplated in the model, and consider also the development of regional maximum wind densities based on land use, setbacks and provincial policy.

Model Opportunity #16: CREST can be upgraded to consider additional renewable resource limitations, such as regional maximum wind densities based on land use, setbacks and provincial policy.

Figure 7: Transmission additions



v. Greenhouse gas emissions

Figure 8 shows results for the greenhouse gas emissions for differing carbon price scenarios in both 2030 and 2050. The charts illustrate electricity system emissions by Province as a proportion of total Canadian emissions (shown on each chart in the upper right corner in MT/year). These results illustrate the following:

Decarbonization: Consistent with the declining proportion of emitting generation (Figure 1), Figure 8 illustrates the corresponding decline in emissions. Under a $50/t carbon price, emissions decline to 50 Mt/year in 2030 from their 2018 level of approximately 70 Mt/year (Natural Resources Canada, 2019a). Under a $200/t carbon price, emissions decline to 9.3 Mt/year in 2030. A similar pattern exists for 2050.

Increased carbon prices required to lower emissions: Under a $50/t carbon price, emissions increase from current levels (70 Mt/year) to more than 85 MT/year by 2050, indicating that a stronger policy signal is needed to lower system-wide emissions.

Policy Implication #8: Under a $50/t carbon price, electricity system emissions increase from current levels (70 Mt/year) to more than 85 MT/year by 2050, indicating that a stronger policy signal is needed to lower system-wide emissions.

Alberta emissions dominate Canada's emissions: Emissions from the Alberta electricity system dominate current and future Canada-wide emissions from the electricity sector, under all carbon pricing scenarios, as a result of the coal and natural gas resources that dominate this system; current system-wide emissions are approximately 50 MT/year (Canada Energy Regulator, 2019). A carbon price above $200/t is required to reduce Alberta emissions by 90% below current levels by 2030 in accordance with the First Ministers' commitment to a Clean Electric Future (Government of Canada, 2018).

Figure 8: Greenhouse Gas Emissions

Emissions increase in some provinces under some scenarios: As a result of the low cost of electricity generated from natural gas, emissions increase slightly by 2030 under a $50/t carbon price in some provinces. For example, British Columbia's emissions increase from ~ 0.5 MT/year currently to more than 8 MT/year in 2050 under a $50/t carbon price. This implies that BC already has a fairly high carbon price implicit in its policies and regulations, including the *Clean Energy Act*. Future iterations of CREST will incorporate existing provincial government policies respecting greenhouse gas emissions from the electricity sector.

Model Opportunity #17: Future iterations of CREST will incorporate existing provincial government policies that place limits on emissions from generation or prescribe renewable generation targets.

vi. Electricity system Costs

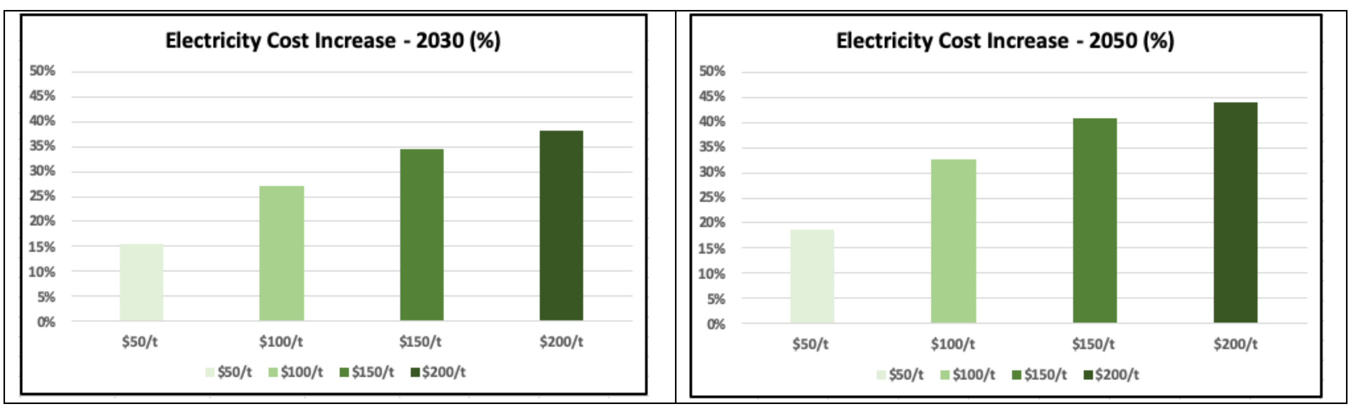
Figure 9 shows the system-wide changes in electricity cost for each carbon price scenario using no carbon price as the baseline. Key observations of these modeled findings include:

Costs increase with carbon price: System-wide electricity costs increase under higher carbon prices, highlighting the higher costs of low-emitting electricity generation as compared to existing fossil fuel generation (particularly natural gas). Compared to the no carbon price baseline, in 2030 costs are 15% higher in the \$50/t scenario and 40% in the \$200/t scenario. For the 2050 target year, costs are 18% higher in the \$50/t scenario and 44% in the \$200/t scenario, indicating that delayed action results in more emissions and higher overall annual costs to eventually reduce those emissions.

Cost increases decrease with carbon price: As shown in Figure 9 for 2030, electricity system-wide costs increase by 15% at \$50/t over costs with no carbon prices. At \$100/t they increase by an additional 12%, at \$150/t by an additional 7%, and at \$200/t by an additional 4%. Similarly, from Figure 8 for 2030, electricity system-wide emissions decrease by 34 MT at \$100/t compare to \$50/t. At \$150/t they decrease by an additional 28 MT, and at \$200/t by an additional 12 MT. The "heavy lifting" in terms of GHG emission reductions and electricity system cost increases takes place at carbon prices below \$150/t, a potentially important finding for policy makers.

Policy Implication #9: The "heavy lifting" in terms of GHG emission reductions and electricity system cost increases take place at carbon prices below \$150/t, a potentially important finding for policy makers.

Figure 9: System-wide costs



4 The modeling ecosystem

4.1 Capacity expansion models

Capacity expansion models (CEM) determine the optimal type, size, timing and location of electrical generation and transmission infrastructure to satisfy system load and reliability criteria, while minimizing total system costs over a defined time horizon. The model results can be used to inform not only utility capacity expansion investments but also costs and opportunities associated with policy aimed at grid decarbonization, low-carbon electrification and other environmental objectives. Our research question, to understand the role of hydroelectric development in grid decarbonization, is particularly well-suited to the application of a capacity-expansion model.

Several previous analyses have employed economic and energy models to assess the future of the Canadian electricity system, considering certain sets of assumptions regarding available technologies, government policies, human behavior and the future structure and growth of the economy.

i. Regional Energy Deployment System

Regional Energy Deployment System (ReEDS) is a CEM designed by the U.S. National Renewable Energy Laboratory (NREL) to assess long-term implications of policy signals on the energy sector. ReEDS specifically addresses issues related to renewable energy technologies, including the accessibility and cost of transmission, regional quality of renewable resources, load and generation profiles, variability of wind and solar output, and the influence of utilities (Short, et al., 2011), (Martinez, et al., 2013). Future fuel prices, hydroelectric generation deployment and policies aimed at renewable energy development each have a significant impact on least cost decision-making within ReEDS (Zinaman, et al., 2015).

Several analyses have used the ReEDS model. One of the earlier and comprehensive analyses (Zinaman, et al., 2015) utilizes ReEDS to analyze the capacity expansion future of the combined US-Canada integrated electricity system. The reference scenario findings in this study show a gradual retirement of coal and nuclear capacity and a significant increase in wind capacity in both countries. Beiter et al. (2017) employ ReEDS to illuminate the evolution of the power system under two scenarios, one in which cross-border transmission capacity is restricted to current levels, and a second scenario in which new transmission is unrestricted. Each of these two scenarios is also considered context of two policy scenarios, namely the application or non-application of a carbon cap and trade system on the power sector that requires a 92% reduction in the combined U.S. and Canadian power sector greenhouse gas emissions by 2050 relative to 2005 emission levels. The results indicate that when new cross-border transmission is prohibited, the United States requires additional capacity (primarily natural gas and renewable energy) to meet domestic needs, while requirements for Canadian installed capacity are reduced, since less capacity is required for electricity exports to the United States. In both policy scenarios, cross-border transmission capacity is projected to double by 2050 (Beiter, et al., 2017).

ii. Other models and applications

SWITCH is a mixed integer linear programming electricity system planning model that minimizes the cost of meeting electricity demand in a target year subject to reliability requirements, operational constraints, and resource-availability constraints while considering existing and possible future climate policies. SWITCH models investment in conventional and renewable generation technologies, storage and transmission lines for meeting hourly electricity requirements over the period 2014 to 2030 across 50 balancing areas within the Western Electricity Coordinating Council. Subject to transmission and generation constraints, the model investigates decarbonization options under various generator technology costs, fuel prices, and carbon policies (Nelson, et al., 2012).

OSeMOSYS is an open source linear program modelling tool for long-term integrated assessment and energy planning that minimizes capital costs, operations costs and carbon prices over the duration of the modeling period. The model does not consider power transmission or electricity storage. Palmer-Wilson et al. (2019) amended OSeMOSYS to consider land use constraints, and to optimize generation capacity in Alberta between 2015 and 2060 under various land impact scenarios. Findings indicate that decarbonizing a fossil fuel based power system using wind and solar generation can lead to a ten-fold expansion of the electricity system land area footprint with implications for competing land uses (Palmer-Wilson, et al., 2019). This competition may result in social conflict concerning land use prioritization, global versus local environmental protection, and preservation of landscape character (Palmer-Wilson, et al., 2019).

The North American TIMES Energy Model (NATEM) is a dynamic linear programing model that maximizes net total consumer and producer surplus. Vaillancourt et al. (2017) use NATEM to explore Canadian energy sector decarbonization pathways by minimizing the cost of emissions reduction between 2015 and 2050. This study explores emission reduction scenarios considering alternative technology futures, including technologies not yet fully commercially developed. To assess the impact of new technologies on GHG reductions, the model assesses two scenarios: one scenario where only commercially proven technologies are included and a second scenario where multiple disruptive technologies are also included in the model database. The results indicate that achieving GHG emissions reduction targets requires three transformations: electrification of end-uses, decarbonization of electricity supply, and energy efficiency improvements (Vaillancourt, et al., 2017).

Qudrat-Ullah (2013) develops and applies a dynamic simulation model to identify a sustainable and balanced electricity capacity expansion scenario in Canada. This model considers inter-temporal interactions between electricity demand, total electricity system investments, production capacity, generation cost, electricity pricing, and environmental sensitivities. The approach used is sectoral in nature, seeking to explicitly model and explain the interactions between electricity supply and demand, research and development and market price-setting sectors that influence electricity capacity expansion in Canada. The findings demonstrate that reaching a sustainable and balanced electricity system requires substantial new investments in electricity generation capacity, electricity efficiency and research and development (Qudrat-Ullah, 2013).

Dolter & Rivers (2018) develop a linear programing optimization model to minimize the cost of Canadian electricity system operation and investment in new generation and transmission, subject to policies for substantial system decarbonization. A static model, the program considers investments within a target future year. Operationally, the model divides the ten provinces within the country into 13 balancing areas that are connected through transmission interties, and further divides these balancing areas into a series of more than 2200 grid cells for modelling the spatial and climatic variation of wind and solar generation. The model's constraints include an hourly balance of supply and demand, limiting transmission intertie flows to their available capacity, applying ramping limits on hourly changes in power production, imposing maximum densities for wind and solar installations within grid cells, and prescribing minimum and maximum annual generation capacity factors. The model considers different pathways to decarbonization including development and integration of VRE capacity, increases in the inter and intra provincial transmission network capacity, development of energy storage and imposition of carbon prices to induce earlier retirement of high emitting generation. The model output identifies pathways for substantially decarbonizing the Canada electricity system at minimum cost. A key insight of the paper is the importance of evaluating trade-offs between hydroelectric, energy storage, and transmission developments for integrating VRE.

The findings of the application of CEMs in Canada illustrate the importance of the uniquely integrated performance of hydroelectric, thermal, transmission and wind resources within the Canadian electricity system. Understanding and appropriately characterizing the individual and collective operations of these resources is key to modeling system performance and to properly informing policymaking.

iii. Limitations of hydroelectric resources in CEMs

Despite the potential for CEMs to contribute to our understanding of low-cost grid decarbonization, the literature consistently identifies limitations in the representation of hydroelectric resources in these models, including: insufficient site-specific hydroelectric data concerning operations and costs (Dolter & Rivers, 2018), (Short, et al., 2011); uncertainties concerning hydrologic inflows and, therefore, seasonal energy constraints and capacity availability (Gil, et al., 2015), (Hemmati, et al., 2013); and computational complexities resulting from nonlinearities (Ramírez-Sagner & Muñoz, 2019) and planning under uncertainty (Gil, et al., 2015). The persistence of these limitations is in part due to the limited application of CEMs within electricity systems, like Canada's, which are dominated by hydroelectric resources. Prior application of CEMs in the Canadian context have included the operations of existing hydroelectric resources while omitting the potential for new hydroelectric development (Dolter & Rivers, 2018), or included the potential for new development without considering the potential for hydroelectric renewals. Indeed, the Trottier Energy Futures Project identified additional hydroelectric capacity and development of pumped storage at existing hydroelectric sites as key gaps in that study (The Canadian Academy of Engineering, 2016).

Given the limited application to date of CEMs within hydroelectric-dominated systems, there is a significant opportunity for improvement, in order to more accurately explore Canada's commitment to reducing economy-wide greenhouse gas emissions over the coming decade.

4.2 Related Studies

i. The Pan-Canadian Wind Integration Study

The Pan-Canadian Wind Integration Study (PCWIS) sought to determine the various impacts of integrating large quantities of wind energy in the Canadian electricity system (GE Energy Consulting, 2016). Key aims of the study included to improve the understanding of operational challenges, production costs and opportunities associated with high wind penetration. Key findings of the study included that it is technically feasible for wind energy to make up 35% of Canadian electricity generation, a substantial increase over current installed capacity of ~9% (Figure 1). This is achieved by expanding installed wind capacity to ~65 GW with concentrations of 15 GW or more in each of Ontario, Quebec, and Alberta (GE Energy Consulting, 2016). Figure 5 in the current study suggests a similar quantity of installed wind capacity of up to 65 GW by 2050, located primarily in the southern prairies, especially Saskatchewan. PCWIS also highlighted a value in the flexibility provided by existing hydroelectric resource utilization, and that the technical, operational and policy limitations to increasing that flexibility needs to be investigated in greater detail. In terms of transmission, PCWIS found that significant additions were required to accommodate increased wind penetration. Specifically, the 20% wind penetration scenario requires 4.6 GW of additional inter-area transfer capacity while the 35% scenario requires about 10 GW of new transfer capacity. In our $200/t scenario in 2050, we find that for 37% wind penetration, over 22 GW of inter-area transfer capacity are required (Figure 7).

ii. RECSI

The Regional Electricity Cooperation and Strategic Infrastructure (RECSI) study was undertaken by Natural Resources Canada (NRCan) to assist the Atlantic and Western provinces in assessing options for furthering electricity sector GHG emissions reductions (Hatch, 2018), (GE Energy Consulting, 2018).

RECSI modeled the cost and GHG emission impacts of various resource options, including early coal retirement or continued operation under emissions limits in Atlantic Canada, and development of specific generation and transmission projects in Western Canada.

The Atlantic RECSI undertakes a production cost analysis using PLEXOS®, a system operations and planning model in common use by Atlantic Canada utilities. The Western RECSI employed GE Concorda Suite Multi-Area Production Simulation (GE MAPS), a security constrained unit commitment and economic dispatch model, meaning that generation dispatch considers transmission and other system constraints.

Relevant findings of the Atlantic RECSI include the following:

- The Atlantic regional electric system changes to meet new coal-fired regulations, with units either retired or operated at lower capacity factors.
- There are limited options to replace the retirement of coal-fired units. Potential options such as the Gull Island hydro project in Labrador and the expansion of Point Lepreau nuclear station are significant and complex projects with long development lead times.
- The implementation of coal regulations will determine the size and timing of new large electricity generation developed to serve regional load.
- Regional electricity transmission reinforcement could enable the introduction of more sources of renewable energy. (Natural Resources Canada, 2018a)

Key relevant findings of the Western RECSI include the following:

- There are several potential future transmission projects in western Canada that reduce GHG emissions and lead to overall electricity production cost savings, including a new Manitoba-Saskatchewan intertie.
- Interprovincial action can achieve deep GHG emissions reductions.
- Electrification of natural gas liquefaction and upstream natural gas production represent particularly compelling GHG reduction opportunities.
- Alberta and Saskatchewan have a number of options to pursue to reduce their respective electricity sector GHG emissions, including additional new hydroelectric development, carbon-capture and sequestration, and further transmission intertie development (Natural Resources Canada, 2018b).

4.3 Canadian Renewable Electricity Storage and Transmission Model

i. Description

First published in an article in *Energy Policy* in 2018, CREST is one of the few applications of a CEM to the electricity system in Canada that also seeks to evaluate least-cost pathways for decarbonizing Canada's electricity system (Dolter & Rivers, 2018). Appealing attributes of this model include optimization of both generation and transmission expansion, analysis on hourly timesteps over an entire year, use of high geographical resolution for the integration of wind and solar resources, and evaluation of the effects of carbon pricing on grid evolution and costs.

Our revised version of CREST operates similarly to its predecessor in that it evaluates competing scenarios for decarbonization, including imposition of carbon prices, advanced retirement of higher-emitting generation (e.g. coal, natural gas, diesel), and expansion of the inter and intra provincial transmission network. Among other revisions, we expand the input dataset for CREST by assembling detailed cost and operational data concerning potential hydroelectric renewals, pumped storage and greenfield hydroelectric developments across Canada. We use this information to inform the redesign of CREST to accommodate consideration of the development of new hydroelectric resources as well as the redevelopment of existing hydroelectric resources as key elements in system capacity expansion under a future of deep decarbonization. By addressing several limitations to hydroelectric representation in CEMs, the current analysis more thoroughly explores Canada's decarbonization opportunities.

ii. Comparisons to other models and studies with similar objectives

Similar to other CEMs used to evaluate capacity expansion in Canada (Zinaman, et al., 2015), (Nelson, et al., 2012), (Vaillancourt, et al., 2017), CREST seeks to assess the long-term implications of policy aimed at GHG emissions reduction. Like these other models, CREST analyzes the electricity sector in the context of increasing deployment of VRE technologies, transmission expansion and the role of balancing resources and energy storage. As with the NATEMS model used by Vaillancourt et al. (2017), CREST is capable of assessing the performance of the full spectrum of generating technologies operating on the Canadian grid, including thermal, VRE, storage and hydroelectric. Like the PCWIS, CREST seeks to model and understand the potential for integrating large quantities of VRE within the Canadian electricity system. Similar to the RECSI, CREST seeks to understand the merits of particular hydroelectric development opportunities.

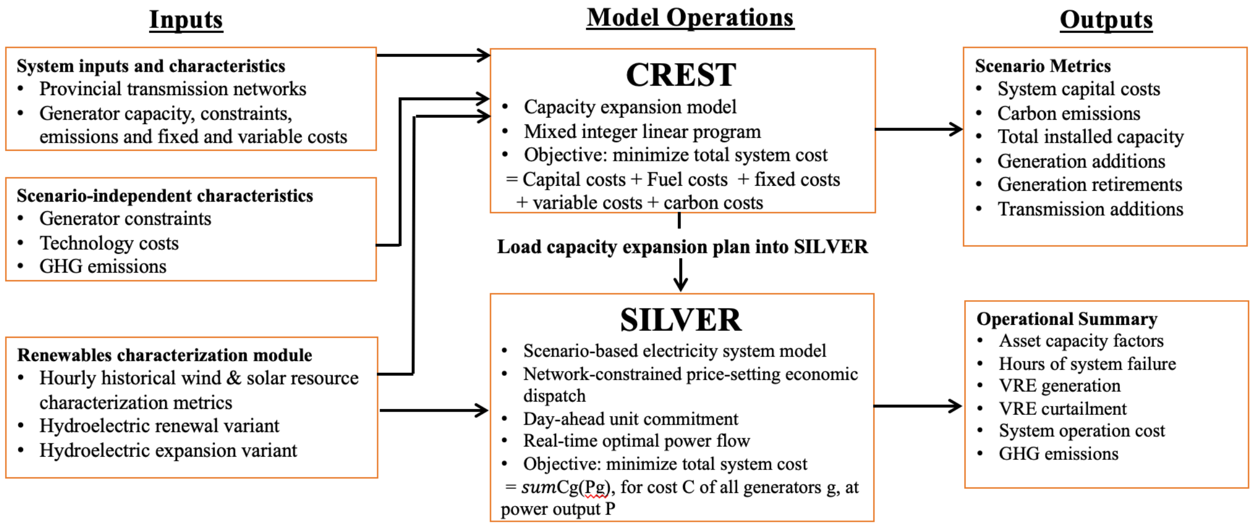
CREST differs from other CEMs by employing a level of spatial disaggregation consisting of balancing areas further divided into a comprehensive spatial grid network. This approach is novel in the Canadian context, and allows for improved characterization of wind and solar generation. CREST was also revised to operate as a mixed integer linear program model, meaning that it is capable of binary ("yes" or "no") as well as continuous ("how much") decisions respecting the addition of generation resources. This is particularly relevant to the consideration of hydroelectric resources, recontracting of existing generating facilities, and the addition or termination of large-scale site-specific generating resources.

iii. Synergies: model coupling

Our research group, Sustainable Energy Systems and Integration and Transitions (SESIT), is currently exploring both soft linking as well as more sophisticated integration of CREST with the production cost model Strategic Integration of Large-capacity Variable Energy Resources (SILVER) (McPherson & Karney, 2017). The output of CREST, specifically the resulting generation and transmission capacity plan, forms the input to SILVER. The eventual integration of these two models will improve characterization of operational realities, which is particularly relevant in the context of increasing deployment of VRE, integration of energy storage and altering the operations of existing hydroelectric development to maximize system value and minimize costs. Further linkages to integrated assessment models would allow exploration of planning and policy options across national and international energy systems.

CREST, particularly when coupled with SILVER, enables policy analysts to evaluate options for grid expansion and differing operations of grid components to achieve decarbonization, electrification and renewables integration at the lowest possible cost. The following figure illustrates the system and renewable resource inputs, the model sequence, key scenario metrics of CREST, and model outputs of SILVER.

Figure 10: CREST-SILVER flow diagram



5 Summary: limitations, opportunities and policy implications

i. Summary

In this report, we present the results of an analysis concerning the evolution of the Canadian electricity system in response to an increasingly strong policy signal in the form of a rising price on greenhouse gas emissions. We find that at a carbon price of \$50/t or higher, all existing coal-fired generation is removed from the Canadian electricity system, while a carbon price of \$200/t is insufficient to remove all natural gas generation. As the lowest-cost source of renewable energy in Canada, installed wind generating capacity increases dramatically with rising carbon prices from the current (2018) installed capacity of 15 GW. At \$200/t in 2030, installed wind capacity rises to 36 GW while at \$200/t in 2050 installed capacity increases to 65 GW as the overall system expands due to electricity demand growth. We find that this quantity of VRE is balanced at low carbon prices primarily by additional natural gas capacity, and at higher carbon prices by increasing installed hydroelectric generation. By 2030, nearly 1,500 MW of hydroelectric renewals are developed in response to rising carbon prices, with an additional 1,500 MW of greenfield hydroelectric developed prior to 2050, under the \$200/t carbon price scenario. Our model proposes new transmission transfer capacity mainly to service regions where significant wind resources are developed.

Our analysis indicates that electricity system GHG emissions decline markedly from current levels of 70 Mt/year (Natural Resources Canada, 2019a) in response to increasing carbon prices, and at \$200/t fall to 9 MT/year and 11 MT/year in the 2030 and 2050 target years, respectively. For the 2030 target year, electricity system costs increase by more than 15% in response to a \$50/t carbon price, by 25% in response to a \$100/t carbon price and by nearly 40% at \$200/t. These results provide insights into the potential impacts associated with Canada's climate policy objectives, as well as into the technology options available for achieving those objectives.

ii. Model limitations

Table 5 summarizes the enhancements to CREST identified in this report. The persistence of these kinds of limitations is in part due to the limited application of CEMs to date within electricity systems like Canada's, which are dominated by hydroelectric resources. Our objective is to address these limitations to improve upon future model characterization and performance.

Table 5: Summary of model limitations in the current iteration of CREST

Item Number	Description
Model Limitation #1:	CREST currently models the overall balance of supply, demand and transmission of electricity at a lower-than-desired geographic resolution. Hourly demand data spatially disaggregated at a regional or substation level would permit CREST to make fuller use of its analytical capabilities.
Model Limitation #2:	The absence of 2018 hourly load data for some provinces required use of modified 2013 hourly load data, which presumes (incorrectly) that hourly demand shifts uniformly in response to changes in annual total electrical energy demand.
Model Limitation #3:	The use of forecasts of annual energy demand in CREST introduces limitations that could be addressed through the use of hourly energy demand forecasts, which the authors understand are currently under development by the Canada Energy Regulator.
Model Limitation #4:	The use by CREST of utility and system operator load forecasts introduces errors in estimation that could be addressed by utility and system operators producing 20-year forecasts not less frequently than every two years. These load forecasts should include low, mid and high forecasts that reflect existing decarbonization and electrification policies, as well as "electrification forecasts" that reflect an estimate of low-carbon electrification required to fully achieve carbon reduction emission objectives.
Model Limitation #5:	The limited number of thermal generation types represented in CREST results in errors in the estimates of system-wide costs and greenhouse gas emissions.
Model Limitation #6:	The exclusion of battery storage, geothermal generation and carbon-capture and sequestration may be precluding opportunities to reduce future system costs.
Model Limitation #7:	Additional research is required concerning the appropriate fleet ramping rates for use in CREST.
Model Limitation #8:	We assumed a 30% reduction in the cost of energy from repowered wind and solar resources compared to similar greenfield resources, based on values from the literature. The potential for error in this assumption could be reduced through additional research in this area as wind and solar repowering becomes more common across Canada.
Model Limitation #9:	The public availability of historical hourly generation data for hydroelectric facilities across Canada would allow for more precise characterization of hydroelectric resources within CREST.
Model Limitation #10:	Based on available information, CREST includes recontracted hydroelectric generation at a levelized cost of energy of $40/MWh. Potential for error in this assumption could be reduced through additional research in this area as recontracting of hydroelectric facilities becomes more common across Canada.
Model Limitation #11:	The agglomeration of recontracted hydro by balancing area may inhibit hydroelectric recontracting. Future iterations of CREST will address this limitation by treating all potential recontracted hydroelectric facilities as individual projects.

iii. Opportunities for future model improvements

As noted at the outset, this report represents the first step in a three-year modelling effort. In submitting this report at this early stage in the research, we are seeking the input of the EMI network on future improvements and expansions as well as how we might collaboratively fill several data gaps. In addition to the limitations we have identified thus far, we also present opportunities for future model improvement that are currently under consideration.

Table 6: Summary of future model opportunities

Item Number	Description
Model Opportunity #1:	Future iterations of CREST could model all potential non-modular generation resources as integer-type decisions (e.g. nuclear, geothermal, natural gas combined cycle) similar to the approach currently used for hydroelectric renewals, pumped storage and greenfield hydroelectric.
Model Opportunity #2:	Increasing the number of balancing areas within CREST would improve model performance in locating and costing new generation and transmission resources.
Model Opportunity #3:	Converting CREST from a static cross-sectional model to a dynamic longitudinal model would allow for the assessment of the effects of policy changes over time.
Model Opportunity #4:	Future iterations of CREST will further disaggregate thermal resources and add additional low-carbon resources (e.g. geothermal) to the potential asset list used in the model.
Model Opportunity #5:	The characterization of interprovincial contracts for energy and capacity within CREST could be improved with the availability of hourly demand and intertie flows between each Province.
Model Opportunity #6:	Future iterations of CREST could include consideration of balancing area reserve requirements in order to more accurately reflect system operations as well as capacity expansion in response to the development and operation of variable renewable generation.
Model Opportunity #7:	Future iterations of CREST will verify and update the distance of potential wind and solar generation to a suitable potential transmission interconnection, and also consider inclusion of substation development costs.
Model Opportunity #8:	Future iterations of CREST will include the potential to model anticipated future cost declines, particularly wind and solar capacity.
Model Opportunity #9:	Future iterations of CREST will include the consideration of “hourly peaking” hydroelectric facilities as distinct from “daily storage” facilities.
Model Opportunity #10:	Future iterations of CREST will improve upon the characterization of facilities located downstream of existing large upstream reservoirs in terms of facility synchronization, inflow quantification and downstream flow requirements.
Model Opportunity #11:	Pursuant to a review of hourly facility generation data and permitting requirements respecting minimum downstream flows, future iterations of CREST will improve upon the estimates of hourly minimum flow requirements for hydroelectric generation.
Model Opportunity #12:	Pending availability of suitable hydroelectric and system data, CREST’s spatial coverage could be expanded to include coverage north of 60˚ latitude to evaluate the potential for interconnection and development of northern hydroelectric resources.
Model Opportunity #13:	Subsequent iterations of CREST could include stranded asset costs potentially incurred upon early retirement of thermal generating facilities.
Model Opportunity #14:	Future iterations of CREST will improve upon the characterization of biomass generation recontracting and CO_2e emissions intensity.
Model Opportunity #15:	Future iterations of CREST will consider sensitivity analyses on the costs of hydroelectric and other generation and transmission resources to determine the robustness of the findings under differing cost assumptions.
Model Opportunity #16:	CREST can be upgraded to consider additional renewable resource limitations, such as regional maximum wind densities based on land use, setbacks and provincial policy.
Model Opportunity #17:	Future iterations of CREST will incorporate existing provincial government policies that place limits on emissions from generation or prescribe renewable generation targets.

iv. Policy implications

The findings of this analysis have several implications for electricity policy in Canada, and we look forward to discussing these implications with the research network.

Item Number	Description
Policy Implication #1:	The carbon price will need to increase beyond current policy to prevent backsliding towards greater installed emitting generation within the Canadian electricity system.
Policy Implication #2:	A carbon price of at least $150/t is required to achieve the First Ministers' commitment to a clean electric future where 90% of Canada's electricity comes from non-emitting sources by 2030.
Policy Implication #3:	Policy direction regarding additional nuclear generation needs to consider scenarios for future demand under low-carbon electrification as well as the availability of lower-cost alternatives.
Policy Implication #4:	Under a policy where carbon prices rise quickly to $50/tonne by 2030, more than 6,000 MW of coal is retired, including all coal currently scheduled to retire after 2030. Carbon pricing plays a role in advancing coal retirements.
Policy Implication #5:	At the higher carbon prices necessary to achieve deep decarbonization, significant quantities of natural gas must be retired, and very little new natural gas capacity can be developed.
Policy Implication #6:	The potential to develop hydroelectric renewals offers a policy alternative for reducing GHG emissions with reduced environmental effects, competitive costs and shorter development timeframes compared to greenfield hydroelectric development.
Policy Implication #7:	Correlations between these initial results and utility plans demonstrates the potential for the model to be further developed as a tool to simulate capacity expansion opportunities under active consideration.
Policy Implication #8:	Under a $50/t carbon price, electricity system emissions increase from current levels (70 Mt/year) to more than 85 MT/year by 2050, indicating that a stronger policy signal is needed to lower system-wide emissions.
Policy Implication #9:	The "heavy lifting" in terms of GHG emission reductions and electricity system cost increases takes place at carbon prices below $150/t, a potentially important finding for policy makers.

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APPENDICES

A. Model Notation

Notation for sets, parameters and variables that are being used in this model:

Symbol	Definition
h	Hours in the year (1:8760)
d	Days in the year (1:365)
m	Months in the year (1:12)
P	All generation types
tp(p)	Thermal electric generating plant types
rp(p)	Renewable generating plant types (wind, solar)
hp(p)	Hydroelectric generating plant types (run-of-river, daily hydro, monthly hydro, pumped storage hydro)
hrp	Set of hydro renewal project
hrcp	Set of all hydro re-contract projects
hy	Set of all hydro types
ap,apa	All provinces (10 provinces, excluding territories)
aba,abba	All balancing areas
l	Grid locations
totalcost	Total cost of supplying electricity for one year
fuelcost	Annual total fuel cost for thermal electricity generation plants
capitalcost	Annual capital cost for all new generation plants
recon_cost	Renewable rebuilding cost
varcost	Variable operations and maintenance cost for all electricity generation plants
fixcost	Fixed operations and maintenance cost for all electricity generation plants

carbon(*ap,aba*)	Annual carbon dioxide emissions for balancing area *aba* and province *ap* expressed in megatonnes (Mt) carbon dioxide equivalent (CO_2e)
fuelprice(*tp*)	Price of fuel in dollars per GJ for plant type *tp*
fuel_CO_2(*tp*)	Carbon dioxide content of fuel in kilograms (kg) CO_2e/Gigajoule (GJ)
$\eta(tp)$	Efficiency of thermal plant *tp* (electrical output per unit of thermal input)
capital_cost(*p*)	Annualized capital cost for electricity plant type *p*
variable_o_m(*p*)	Variable operations and maintenance cost per megawatt-hour (MWh) electricity generated for plant type *p*
fixed_o_m(*p*)	Annual fixed operations and maintenance cost per megawatt (MW) installed capacity per year for plant type *p*
store_cost	Annualized capital cost for new pumped hydroelectric storage capacity
trans_cost	Annualized capital cost for constructing new high voltage transmission capacity, in dollars per MW-kilometer (km)
intra_ba_transcost	Annualized capital cost for constructing transmission to connect new wind and solar facility with existing transmission grid, in dollars per MW-km of capacity
distance(*aba,ap,abba,apa*)	Distance in km between centroid of balancing area *aba* in province *ap* to balancing area *abba* in province *apa*
distance_to_grid(*l*)	Distance in km between centroid of MERRA grid cell and nearest transmission line
trans_loss(*aba,ap,abba,apa*)	Share of electricity lost in transmitting from balancing area *aba* in province *ap* to balancing area *appa* in province *apa*
capacity_factor(*h,l,rp*)	Capacity factor for a renewable plant of type *rp* built at location *l* in hour *h*
extant_renew_capacity(*l,rp*)	Extant renewable electricity generating capacity in location *l* by plant type *rp*
ba_pump_hydro_capacity (*aba,ap*)	Extant pumped hydro storage capacity in balancing area *aba* and province *ap*

demand_us(*h,aba,ap*)	Demand for electricity exports to the United States by hour *h* in each balancing area *aba* and province *ap*
demand(*h,aba,ap*)	Electricity demand by hour *h* in each balancing area *aba* and province *ap*
supply(*h,aba,ap,tp*)	Supply of electricity (MWh) in hour *h* in balancing area *aba* in province *ap* by plant type *tp*
windout(*h,aba,ap,wind*)	Wind electricity (MWh) generated in hour *h* in balancing area aba and province ap
pumpenergy(*h,aba,ap*)	Stored potential energy in pumped hydroelectric storage facilities in hour *h* in balancing area *aba* in province *ap*
pumpout(*h,aba,ap*)	Stored potential energy released and used to meet demand in hour *h* balancing area *aba* and province *ap*
pumpin(*h,aba,ap*)	Electricity used to increase stored potential energy of pumped hydroelectric storage in hour *h* balancing area *aba* and province *ap*
daystoragehydroout(*h,aba,ap*)	Hydroelectric output in hour *h*, balancing area *aba* and province *ap* from facilities that are capable of storing potential energy over the course of 24 hours
monthstoragehydroout(*h,aba,ap*)	Hydroelectric output in hour *h*, balancing area *aba* and province *ap* from facilities that are capable of storing potential energy over the course of a month
transmission(*h,aba,ap,abba,apa*)	Transmission of electricity from balancing area *aba* in province *ap* to balancing area *abba* in province *apa*
gen_capacity(*aba,ap,tp*)	New electricity generating capacity in balancing area *aba* in province *ap* by plant type *tp*
renew_gen_capacity(*l,rp*)	New electricity generating capacity in location *l* by plant type *rp*
capacity_trans(aba,ap,abba,app)	New installed transmission capacity
retirements(*aba,ap,p)*	Extant electricity generation retired in balancing area *aba* in province *ap* by plant type *p*
capacity_transmission (*aba,ap,abba,apa*)	Transmission capacity in MW from exporting balancing area *aba* in province *ap* to importing balancing area *abba* in province *apa*

B. Model Equations

- Objective function of the model:

$$Min. total\ cost = capitalcost + \ fuelcost + fixcost \ + \ \ varcost + carbon\ costs. \quad (1)$$

In which:

$$capitalcost = \sum_{aba,ap,tp} gen\_capacity_{aba,ap,tp} \times capital\_cost_{tp}$$
$$+ \sum_{l,rp} renew\_gen\_capacity_{l,rp} \times capital\_cost_{l,rp}$$
$$+ \sum_{l,rp} renew\_recon\_capacity_{l,rp} \times recon\_cost_{l,rp}$$
$$+ \sum_{hrp} hydro\_renewal\_binary_{hrp} \times capital\_cost_{hrp}$$
$$+ \sum_{hrcp} hydro\_recon\_binary_{hrcp} \times capital\_cost_{hrcp}$$
$$+ \sum_{aba,ap,abba,apa} distance_{aba,ap,abba,apa} \times capacity\_transmission_{aba,ap,abba,apa}$$
$$\times trans\_cost. \quad (2)$$

$$fuelcost = \sum_{h,aba,ap,tp} supply_{h,aba,ap,tp}$$
$$\times \left(\left(fuelprice_{tp} + \left(ctax \times fuel\_CO2_{tp} \right) \right) \times 3.6 \times \frac{1}{\eta_{tp}} \right). \quad (3)$$

$$fixcost = \sum_{aba,ap,tp} \Big(\big(extant\_capacity_{aba,ap,tp} - retirements_{aba,ap,tp} + gen\_capacity_{aba,ap,tp}$$
$$+ \big) \times fixed\_o\_m_{tp} \Big)$$
$$+ \sum_{l,rp} (extan\_renew\_capacity_{l,rp} + renew\_gen\_capacity_{l,rp}$$
$$+ renew\_recon\_capacity_{l,rp}) \times fixed\_o\_m_{rp}$$
$$+ \sum_{aba,ap,hy} extant\_capacity_{aba,ap,hy} \times fixed\_o\_m_{hy}$$
$$+ \sum_{hrp} hydro\_renewal\_capacity_{hrp} \times hydro\_renewal\_binary_{hrp} \times fixed\_o\_m_{hrp}$$
$$+ \sum_{hrcp} hydro\_recon\_capacity_{hrcp} \times hydro\_recon\_binary_{hrcp}$$
$$\times fixed\_o\_m_{hrcp} \quad (4)$$

$$varcost = \sum_{h,aba,ap,tp} supply_{h,aba,ap,tp} \times variable\_o\_m_{tp} + \sum_{h,l,rp} supply_{h,l,rp} \times variable\_o\_m_{rp} + \sum_{h,aba,ap,hy} supply_{h,hy} \times variable\_o\_m_{hy} \quad (5)$$

Constraints:

1- Supply and demand equality constrain:

$$\sum_{p} supply_{h,aba,ap,p} \geq demand_{h,aba,ap} + demand\_us_{h,aba,ap} + \sum_{abba,apa} transmission_{h,aba,ap,abba,apa} - (1 - trans_{loss}{}_{abba,app,aba,ap}) \times \sum_{abba,apa} transmission_{h,abba,app,aba,ap} \quad \forall h, aba, ap. \quad (6)$$

2- The constraint that limit generation in each hour to the installed capacity for all type of generation:

$$\sum_{aba,ap,tp} supply_{h,aba,ap,tp} \leq extant_{capacity}{}_{aba,ap,tp} + gen_{capacity}{}_{aba,ap,tp} - retirements_{aba,ap,tp} \quad (7)$$

3- Limit maximum retirement to the total installed capacity in each balancing area and for all type of thermal plants

$$\sum_{aba,ap,tp} retirements_{aba,ap,tp} \leq extant\_capacity_{aba,ap,tp} \quad (8)$$

4- limit transmission of power between to balancing area to the installed capacity

$$transmission_{h,aba,ap,abba,apa} \leq extant\_trans\_capacity_{aba,ap,abba,apa} + capacity\_trans_{aba,ap,abba,apa} \; \forall h, aba, ap, abba, apa. \quad (9)$$

5- Limit output of renewable power plants to the total installed capacity:

$$\boldsymbol{renew}\_out_{h,l,rp} \leq capacity\_factor_{h,l,rp} \times \left(renew\_gen\_capacity_{l,rp} + extant\_renew\_capacity_{l,rp}\right) \; \forall h, l, rp \quad (10)$$

6- Maximum and minimum capacity factor for thermal plants:

$$Capacity\_factor_{aba,ap,tp} \ \leq \ Maximum\_Capacity\_factor_{tp} \quad (11)$$

$$Capacity\_factor_{aba,ap,tp} \ \geq \ Minimum\_Capacity\_factor_{tp} \quad (12)$$

7- Pump storages constraints:

7.1- limit potential energy that can be stored in a pumped hydro reservoir:

$$\begin{aligned} pumpenergy_{aba,ap} & \\ & \leq (ba\_pump\_hydro\_capacity_{aba,apa} \\ & + \sum\nolimits_{hrp} hydro\_renew\_capacity_{hrp} \times hydro\_renew\_binary_{hrp} \ \ if \ \ hrp \\ & \in hr\_pump\&hr\_loc \in aba, ap) \ \times \ pump\_hours \quad (13) \end{aligned}$$

7.2- the amount of energy stored in the pumped hydro reservoir at any given hour:

$$\begin{aligned} pumpenergy_{h+1,ap,aba} & \\ & = pumpenergy_{h,ap,aba} - \ pumpout_{h,ap,aba} \\ & + \ pumpin_{h,ap,aba} \ \times \ \eta_{pump} \ \forall h, ap, ab, \qquad (14) \end{aligned}$$

7.3- Limit the rate at which potential energy can be added to the pumped hydro facility, and limit the amount of electricity that can be generated at any given time:

$$\begin{aligned} pumpin_{h,ap,aba} \ \times \ \eta_{pump} & \\ & \leq \ ba\_pump\_hydro\_capacity_{aba,apa} \\ & + \sum\nolimits_{hrp} hydro\_renew\_capacity_{hrp} \times hydro\_renew\_binary_{hrp} \ \ if \ \ hrp \\ & \in hr\_pump\&hr\_loc \in aba, ap \quad \forall h, ap, aba \quad (15) \end{aligned}$$

$$\begin{aligned} pumpout_{h,ap,aba} & \\ & \leq \ ba_{pump_{hydro_{capacity}}}{}_{aba,apa} \\ & + \sum\nolimits_{hrp} hydro_{renew_{capacity}}{}_{hrp} \times hydro_{renew_{binary}}{}_{hrp} \ \ if \ \ hrp \in hr\_pump\&hr\_loc \\ & \in aba, ap \ f \quad \forall h, ap, aba. \quad (16) \end{aligned}$$

8- Daily and monthly hydroelectric constraints:

8.1- Limit output energy to the maximum available energy

$$\sum_{h \in d} day\_hydro\_out_{h,ap,aba} \ \leq \ day\_hydro\_historic_{d,ap,aba} \ \ \forall d, ap, aba \ \ (17)$$

$$\sum_{h \in d} day\_renewal\_out_{h,hrp} \leq day\_renewal\_historic_{d,hrp} \quad \forall d, hrp \in hr\_day \;\; (18)$$

$$\sum_{h \in m} month\_hydro\_out_{h,ap,aba} \leq month\_hydro\_historic_{m,ap,aba} \quad \forall m, ap, aba. \;\; (19)$$

$$\sum_{h \in m} month\_renewal\_out_{h,hrp} \leq month\_renewal\_historic_{m,hrp} \quad \forall m, hrp \in hr\_month \;\; (20)$$

8.2- The following constraint impose minimum flow:

$$day\_hydro\_out_{h,ap,aba} \geq day\_\min\_flow_{ap,aba} \;\; \forall h, ap, aba \;\; (21)$$

$$day\_renewal\_out_{h,hrp} \geq day\_\min\_flow_{hrp} \;\; \forall h, hrp \in hr\_day \;\; (22)$$

$$month\_hydro\_out_{h,ap,aba} \geq month\_\min\_flow_{ap,aba} \;\; \forall h, ap, aba. \;\; (23)$$

$$month\_renewal\_out_{h,hrp} \geq month\_\min\_flow_{hrp} \;\; \forall h, hrp \in hr\_month \;\; (24)$$

8.3- Capacity constraint, ensure that the amount of electricity generated at any point in time does not exceed the installed capacity of the generator:

$$day\_hydro\_out_{h,ap,aba} \leq day\_hydro\_capacity_{ap,aba} \;\; \forall h, ap, aba \;\; (25)$$

$$day\_renewal\_out_{h,hrp} \leq day\_renewal\_capacity_{hrp} \times hydro\_renewal\_binary_{hrp} \;\; \forall h, hrp \in hr\_day \;\; (26)$$

$$month\_hydro\_out_{h,ap,aba} \leq month\_hydro\_capacity_{ap,aba} \;\; \forall h, ap, aba. \;\; (27)$$

$$month\_renewal\_out_{h,hrp} \leq month\_renewal\_capacity_{hrp} \times hydro\_renewal\_binary_{hrp} \;\; \forall h, hrp \in hr\_month \;\; (28)$$

9- Ramping constraints on thermal generation units:

$$\begin{aligned} supply_{h+1,aba,ap,tp} & \\ &\leq supply_{h,ap,aba,tp} \\ &+ \left(extant\_capacity_{aba,ap,tp} - retirements_{aba,ap,tp} + gen\_capacity_{aba,ap,tp}\right) \\ &\times ramp\,rate_{tp} \quad \forall h, ap, aba, tp \quad (29) \end{aligned}$$

$$supply_{h+1,aba,ap,tp} \geq supply_{h,ap,aba,tp} - \left(extant\_capacity_{aba,ap,tp} - retirements_{aba,ap,tp} + gen\_capacity_{aba,ap,tp}\right) \times ramp\,rate_{tp} \quad \forall h, ap, aba, tp. \quad (30)$$

10- Density constraint, limit the amount of wind and solar power capacity that can be installed in any grid cell.

$$renew\_\,gen\_capacity_{l,rp} \leq \max\,\_renew\_capacity_{l,rp} \quad \forall l, rp. \quad (31)$$

C. Tables and Figures

Table 7: Load forecasts and annual energy demand modeled growth rates

Province	Forecast Period	Forecast Duration	Modeled Growth Rate 2018-2030	Modeled Growth Rate 2018-2050	Source
		(years)	(%)	(%)	
British Columbia	2017-2036 2020-2039	20 years 20 years	1.10	0.99	(BC Hydro, 2016) (BC Hydro, 2019)
Alberta	2019-2039	20 years	1.23	1.07	(AESO, 2019)
Saskatchewan	2017-2036	20 years	1.14	1.17	(Saskpower, 2018)
Manitoba	2018-2037	20 years	0.44	0.78	(Manitoba Hydro, 2018)
Ontario	2016-2035	20 years	-0.02	0.21	(IESO, 2016)
Québec	2019-2029	10 years	0.56	0.56	(Hydro Québec Distribution, 2019)
New Brunswick	2018-2027	10 years	0.12	0.12	(NB Power, 2018)
Prince Edward Island	2018-2021	3 years	1.46	1.23	(Maritime Electric, 2018)
Nova Scotia	2018-2028	10 years	-0.28	-0.28	(Nova Scotia Power, 2018)
Newfoundland and Labrador	2019-2030	12 years	0.19	0.19	(Nalcor Energy, 2019)

Table 8: Generation types used in CREST

CREST Generation Type	Included technologies	Typical Capacity	Economic Life	Annualized Capital Cost	Annual Fixed O&M	Annual Variable O&M	Fuel Costs	Construction Time	GHG Intensity	Thermal Efficiency
		(MW)	(years)	($/MW-y)	($/MW-y)	($/MWh)	($/GJ)	(years)	(kg CO_2e/GJ)	(%)
Coal	Coal steam turbine	1,200.00	40	499,000	75,340	10.59	2.64	4	90	
Gas	Natural gas combined cycle Natural gas cogeneration	1,100.00	30	106,450	13,900	2.78	4.53	3	51	0.509
Peaker	Natural gas combustion turbines Diesel combustion turbines Gas combustion turbines	237.00	30	145,950	9,460	14.88	4.53	2	51	0.280
Nuclear	Nuclear	2,234.00	40	883,900	139,470	3.20	0.93	6	0	0.327
Diesel	Diesel steam turbines Oil steam turbines	85.00	30	176,830	9,600	8.14	16.57	2	72	0.39
Waste	Biogas Biomass cogeneration Biomass steam turbine Municipal solid waste	50.00	30	516,850	154,430	7.70	2.85	4	0	0.39
Wind	On-shore wind	100.00	30	199,080	59,400	0.00	0.00	2	0	n/a
	Recontracted on-shore wind	100.00	30	121,550	59,400	0.00	0.00	1	0	n/a
Solar	Land-based solar photovoltaic	23.00	30	142,670	18,900	0.00	0.00	2	0	n/a
	Recontracted wind	23.00	30	94,200	18,900	0.00	0.00	1	0	n/a
Hydro	Existing hydro	100.00	40-70	n/a	38,440	7.26	0.00	n/a	0	n/a
	Recontracted hydro	65.00	40	58,870	54,930	7.84	0.00	1	0	n/a
	New hydro	by facility	by facility	by facility	by facility	by facility	0.00	by facility	0	n/a
Sources:	(EIA, 2015); (EIA, 2019a); (NREL, 2019); (BC Hydro, 2013b); (EIA, 2019b); (EIA, 2019c); (EIA, 2019d); authors' calculations								(Dolter & Rivers, 2018)	
Notes:	1. Exchange rate: 1 USD = 1.35 CAD 2. Capital overhead rate: 1.77% ((BC Hydro, 2016) 3. Interest during construction: 5.00% 4. Weighted average cost of capital: 7:00%									

Table 9: Long-term electricity contracts included in CREST

Parties	Description	Term
Manitoba Hydro, Saskpower	25 MW – export from Manitoba to Saskatchewan	2015-2022
Manitoba Hydro, Saskpower	100 MW – export from Manitoba to Saskatchewan	2020-2040
Manitoba Hydro, Saskpower	215 MW – export from Manitoba to Saskatchewan	2015-2022
Manitoba Hydro, Basin Electric Power Cooperative	80 MW – export from Manitoba to USA	2023-2028
Manitoba Hydro, Minnesota Power	250 MW – export from Manitoba to USA	2020-2035
Manitoba Hydro, Wisconsin Public Service	100 MW – export from Manitoba to USA	2021-2027
Manitoba Hydro, Xcel Energy	125 MW – export from Manitoba to USA	2021-2025
Manitoba Hydro, Xcel Energy	375 MW – export from Manitoba to USA	2015-2025
CF(L)Co., Hydro Québec	4900 MW – export from Labrador to Quebec	1971-2041
Nalcor, Emera (Nova Scotia Power Inc.)	153 MW – export from Newfoundland to Nova Scotia	2020-2055
Hydro Québec, Cornwall Electric	145 MW – export from Québec to Ontario	2009-2029
Hydro Québec, Vermont Joint Owners	225 MW – export from Québec to USA	2013-2038
NB Power, Maritime Electric	30 MW – export from New Brunswick to PEI	1983-2024
Sources: (Manitoba Hydro, 2019); (Hydro Québec, 2019); (Power Advisory LLC, 2015); (Dunsky Energy Consulting, 2019)		

Table 10: Generator type fleet ramping rates used in CREST (% per hour)

Generator Type	Previous iteration	Current iteration
Natural Gas Combined Cycle	0.25	0.1
Natural Gas Simple Cycle	1.00	0.1
Nuclear	0.01	0.05
Coal	0.1	0.05
Diesel	0.25	0.1
Waste	0.01	0.05

Table 11: Initial list of designated monthly storage hydroelectric watersheds and facilities

Balancing Area	Watershed	Facilities
British Columbia	Peace River	G.M. Shrum, Peace Canyon, Site C
	Columbia River	Mica, Revelstoke
Manitoba	Nelson River	Jenpeg, Kelsey, Kettle, Limestone, Longspruce
Québec	La Grande	Brisay, Laforge-1, La Grande-4, La Grande 3, La Grande 2-A, Robert Bourassa
	Manicouagan	Manic-5, Manic-5-PA
	Bersimis	Bersimis-1
	Outardes	Outardes-4
	Eastmain	Eastmain-1, Eastmain 1-A
	Outaouais	Rapide-7
	St. Maurice	Rapide Blanc
	Romaine	Romaine-4, Romaine-3, Romaine-2
	Hart-Jaune	Hart-Jaune
	Gatineau	Mercier
	Sainte-Margeurite	Sainte-Margeurite-3
	Toulnustouc	Toulnustouc
Labrador	Churchill	Churchill Falls, Muskrat Falls
Newfoundland	Salmon	Granite Canal, Upper Salmon, Bay D'Espoir

Table 12: Variations in transmission costs by terrain and voltage

New Power Line Voltage (kV)	Cost ($/km), $2011			
	Average Overhead Line Slope (0-15 per cent)	Average Overhead Line Slope (16-30 per cent)	Average Overhead Line Slope (>30 per cent)	Submarine Cable
25	84,800	169,600	254,400	500,000
69	106,000	212,000	318,000	1,000,000
138	159,000	318,000	477,000	3,600,000
230	265,000	530,000	795,000	5,300,000
500	530,000	1,060,000	1,590,000	7,100,000
Source:	(BC Hydro, 2013a)			

Table 13: Initial scenarios modeled in CREST

Target Year	Carbon Price	Sampling Ratio	Run Days	Recontracting Included
2030	$0/t	1/5	365	Yes
2030	$50/t	1/5	365	Yes
2030	$100/t	1/5	365	Yes
2030	$150/t	1/5	365	Yes
2030	$200/t	1/5	365	Yes
2050	$0/t	1/5	365	Yes
2050	$50/t	1/5	365	Yes
2050	$100/t	1/5	365	Yes
2050	$150/t	1/5	365	Yes
2050	$200/t	1/5	365	Yes
2030	$0/t	1/5	365	No
2030	$50/t	1/5	365	No
2030	$100/t	1/5	365	No
2030	$150/t	1/5	365	No
2030	$200/t	1/5	365	No
2050	$0/t	1/5	365	No
2050	$50/t	1/5	365	No
2050	$100/t	1/5	365	No
2050	$150/t	1/5	365	No
2050	$200/t	1/5	365	No