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Assessment of renewable energy transition pathways for a fossil fuel-dependent electricity-producing jurisdiction

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ABSTRACT

This research assesses the transition of a fossil fuel-based electricity production jurisdiction to a renewable-based electricity jurisdiction through an extensive scenario analysis. This fills a knowledge gap where a wide-range of fossil-to-renewable electricity generation pathways is compared within a single analysis framework. To conduct this study, a novel data-intensive electricity system model was developed with the Long-range Energy Alternatives Planning system and applied to evaluate alternative electricity generation mix scenarios to the year 2050. A case study for Alberta, a fossil fuels-based province in Canada, was conducted. A total of 382 scenarios were analyzed considering different renewable pathways and varying key uncertain future conditions. The greenhouse gas emission abatement and marginal greenhouse gas abatement costs of each scenario were evaluated and compared. Several renewable-based scenarios resulted in significant greenhouse gas abatement at lower costs than the fossil-fuel based business-as-usual scenario. The maximum greenhouse gas abatement possible at a net cost reduction compared to the business-as-usual scenario was found through a specific combination of wind, hydro, and solar power which resulted in over a 90% reduction from 2005 emission levels at −$1.8/t of carbon dioxide equivalent abated. The results of this study provide policy insight for jurisdictions transitioning away from fossil fuel-based electricity to renewables.

Introduction

As of 2019, 41% of global energy-related CO_2 emissions (33 billion tonnes (t) CO_2e) are from the electricity generation sector (IEA, 2020). Estimates show that 70–85% of global electricity in 2050 may need to come from renewable energy technologies and that greenhouse gas (GHG) emissions may need to reach net zero by 2050 to limit the global temperature rise to 1.5 degrees Celsius and avoid further risk to economic growth, the environment, and ecosystems (IPCC, 2018). This is a momentous challenge since about two-thirds of global electricity generation is from fossil fuels, with coal accounting for ~78% of electricity generation GHG emissions (10 billion tCO_2e) and 30% of total CO_2 emissions from energy (IEA, 2019). Moreover, coal is expected to remain a primary source of electricity generation in the future and supply about a quarter of the energy for electricity generation in 2040 (EIA, 2020). Given these outlooks, the urgency to transition the global electricity sector to one that practices sustainable production of electricity, is apparent. This implies using higher amounts of renewable resources rather than fossil fuels, which will lower negative environmental and ecological damage through reduction of pollution, greenhouse gas, and fossil fuel exploitation activities. In order to facilitate this transition, important and far-reaching decisions must be made regarding sustainable electricity development.

Canada is a country that is regulating phase out of its coal-based electricity and targeting to increase the amount of electricity generation by renewables (Government of Canada, 2016, 2018). The federal government has also announced plans to legislate net-zero emissions by 2050 (2019 Liberal Party of Canada, 2019). The Canadian province of Alberta contributes nearly 60% of Canada's electricity sector GHG emissions (Davis, Ahiduzzaman, & Kumar, 2018). Alberta currently generates 90% of its electricity from fossil fuels and acquires only 10% from renewables (AUC, 2018). Thus, a significant transition is required for Alberta to decarbonize its electricity sector, somewhat mirroring the current global predicament. It not clear what clean production pathways or combinations of technologies would be best suited for the transition, given the wide range of low-carbon options, fast changing costs of renewables, and the sensitivity of their cost-effectiveness. In-depth analysis on long-term renewable electricity generation transitions can shed light on this issue considering resource availability, energy prices, economic development, and government policy, and can also help to inform developing countries to transition away for coal.

Different assessments of GHG mitigation in jurisdictional electricity sectors can be found in the literature. McPherson and Karney developed

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Abbreviations

AESO	Alberta Electric System Operator
AUC	Alberta Utility Commission
CAD	Canadian dollar
CER	Canadian Energy Regulator
CO_2e	Carbon dioxide equivalent
CTG	Coal-to-gas
ECR	Early coal retirement
LEAP	Long-range Energy Alternatives Planning
Mt	Million tonnes (metric)
NGCC	Natural gas combined cycle
NGSC	Natural gas simple cycle
t	Tonne (metric)

a model to analyze diversified power generation mix scenarios in Panama with the aim of reducing GHG emissions (McPherson & Karney, 2014). The study identified four opportunities to reduce both GHG emissions and system generating costs. Chang et al. investigated the impact of various emission constraints on the Shanghai power system supply (Chang, Wu, Pan, Zhu, & Chen, 2017). They were able to estimate cost and technology development implications on the electricity systems under thirteen scenarios including sensitivity analysis. Other literature investigating renewable electricity generation pathways can be found on Brazil (Volpi, Jannuzzi, Dourado, & Gomes, 2006), Mexico (Grande-Acosta & Islas-Samperio, 2017), Pakistan (Amer & Daim, 2011), Tanzania (Felix & Gheewala, 2012), the United Kingdom (Stamford & Azapagic, 2014), and the United States (Ghanadan & Koomey, 2005) to name a few others. There has been limited long-term analysis in the literature on Alberta electricity carbon-reduction. Dolter and Rivers optimized various scenarios of the Canadian electricity system considering different carbon prices (Dolter & Rivers, 2018). The study only considered a single year, 2025, and did not rigorously analyze Alberta results. Lyseng et al. evaluated 13 scenarios using a linear programming optimization model to determine specific carbon price thresholds that would achieve different levels of decarbonization (Lyseng et al., 2016). They did not assess a wide range of technology options irrespective of a carbon price and at the time of the study the projections for wind and solar costs were significantly higher than the presently realized costs and recent cost reduction trends. Keller et al. also used an optimization model and investigated the impacts of converting coal power plants to use biomass feedstock, but this is only a single technology change and thus gives limited insight for sector-wide transitions (Keller et al., 2018). Agrawal et al. investigated GHG abatement, marginal costs, and water consumption of Alberta electricity generation scenarios using an energy accounting model (Agrawal, Ahiduzzaman, & Kumar, 2018). Because the focus of their work was on water-use footprints, their electricity model and scenario analysis were not rigorously developed since all capacity expansions were exogenous assumptions, only 9 scenarios were considered, and they did not consider high levels of renewables.

There has been limited assessment considering wide-ranging technology mixes that are possible to transition an electricity sector from fossil fuels to renewables over the long-term. More specifically, there is a knowledge gap in the electricity transition literature whereby a wide-range of fossil-to-renewable energy scenarios have not been assessed within a single analysis framework so that the options can be effectively compared. We perform this assessment by evaluating 382 long-term scenarios in the Alberta electricity sector considering different technology mixes with high renewable capacity expansions under different sets of future conditions within a single study framework. We compare the options via marginal abatement cost curves to fill these knowledge gaps. Further, an assessment of different technology-mixes meeting Alberta's 30% renewable electricity generation policy target has not been carried out. We extend this analysis by also assessing scenarios that can meet a hypothetical policy of 50% renewable electricity generation by 2050. Additionally, we assess three different carbon price schemes and their impact on the various technology mixes.

This analysis offers new information to support the clean Canadian electricity transition as well as general insights for other jurisdictions transitioning from high to low-carbon electricity systems. The specific objectives of this study are to:

- Develop a long-range data-intensive model for electricity system transition
- Formulate alternative electricity generation mix scenarios to cover the feasible technology options and possible future conditions
- Assess each scenario and compare their GHG abatement and marginal GHG abatement costs to 2050 using the marginal abatement cost curve

Method

Study overview

Fig. 1 shows a flow chart of the procedure followed in this study. The initial stage involves developing the Alberta electricity system model using the Long-range Energy Alternatives Planning (LEAP) modelling system (described in the next). The LEAP modelling framework section describes LEAP generally. Developing the Alberta electricity system model (LEAP-AES) first involved defining a framework considering the sources of electricity demand, types of electricity generation technology, import and export capabilities, and upstream processes in Alberta. The LEAP-AES framework section describes the conceptual framework that was implemented in the LEAP model. Data for electricity requirements, electricity system capacities and generation, GHG emissions, and costs were collected and used to form the model. These data, as well as assumptions and the LEAP modelling methods that were used, are described in detail in the Electricity requirements to Electricity supply sections. The Scenario analysis section covers the Scenario formulation and the Cost-benefit analysis method of scenarios. A multitude of future scenarios was developed for the 2019–2050 time period. The premise of scenario development was to differ the types and combinations of technologies used to transition from a fossil-fuel-based electricity sector to a low-carbon electricity sector and to test the robustness through varying the future electricity demands, costs of key technologies and fuels, carbon price policies, and renewable generation policies. Cost-benefit analysis of each alternative scenario was carried out by comparing the GHG abatement and marginal GHG abatement costs to a business-as-usual scenario. The calculation of these indicators is described in the Cost-benefit analysis section.

Development of the Alberta electricity system model

LEAP modelling framework

Integrated assessments that combine one or more elements of energy-environment-economy are a common approach to conduct long-term energy transition studies for jurisdictional electricity sectors and have been recognized for influencing energy and environmental policy development (Berntsen & Trutnevyte, 2017). These approaches can provide estimations of different indicators including costs, GHG emission reduction potential, electricity supply adequacy, resource requirements, and other important details for developing marginal abatement costs and effective energy policy.

The Long-range Energy Alternatives Planning (LEAP) system is a framework for energy-environment investigation in all sectors of an economy. It is an accounting-based analytical tool for energy consumption, production, and resource extraction with built-in optimization

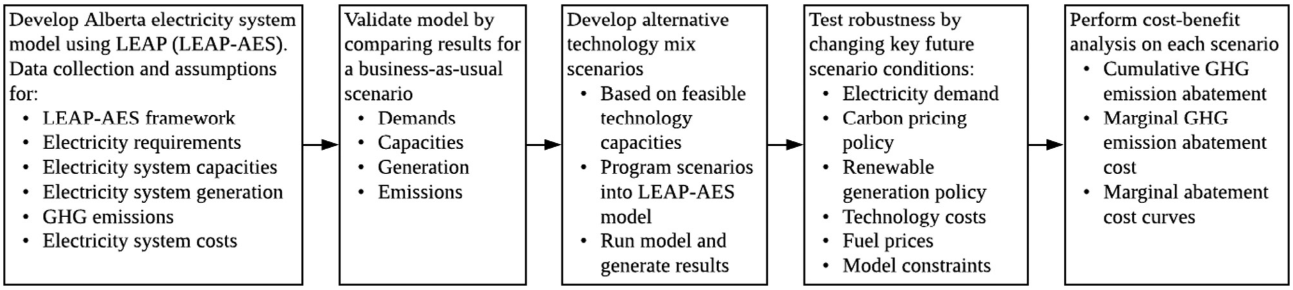

Fig. 1. Overview of study methods.

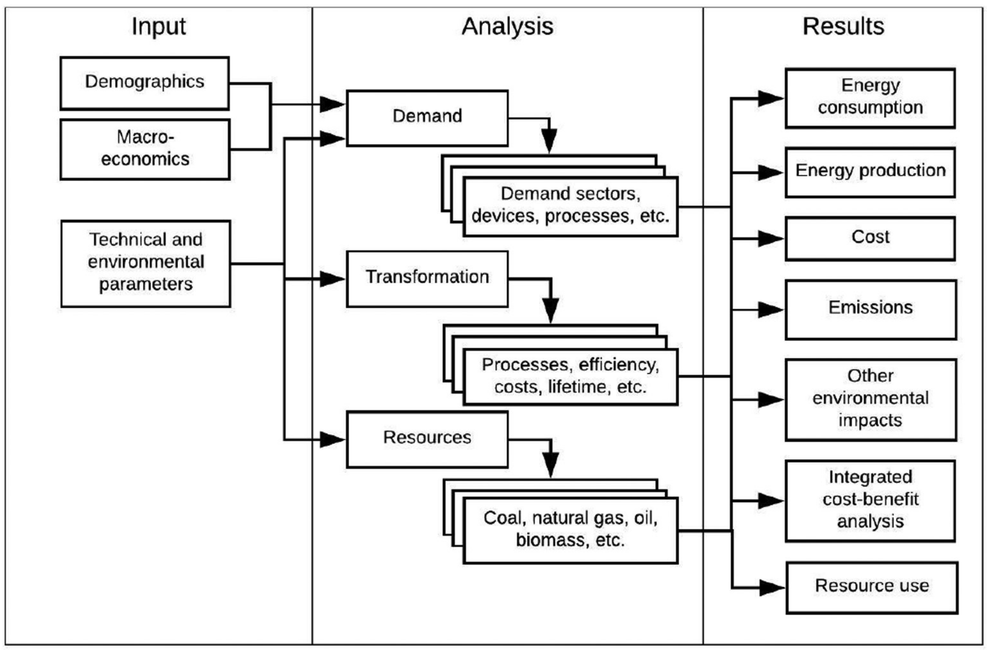

Fig. 2. Basic LEAP model framework.
(Diagram adapted from C. Heaps and the Stockholm Environment Institute)
(Heaps, 2019; Stockholm Environment Institute, 2016).

features for electricity generation (Heaps, 2019). The LEAP framework (shown in Fig. 2) allows the modeller to establish demand, transformation, resource, and environmental characteristics for developing location- and sector-specific energy models. Calculations begin with the demand module, where fuel requirements are determined. The transformation module responds to produce the required fuels by converting resources with the modelled processes. In this study, the integrated Open Source Energy Modeling System (OSeMOSYS) within the LEAP transformation module was used to calculate electricity technology capacities and dispatch of electricity. The Alberta electricity demand, transformation, and resource characteristics were modelled using this framework and are described in detail in the subsequent sections.

LEAP-AES framework

Fig. 3 illustrates the LEAP-AES system with a simple conceptual framework diagram. The model covers the time range 2005–2050; 2005–2018 is used for validation and 2019–2050 is the scenario analysis period. The arrow directions show the flow of energy, but the calculations occur in the opposite direction starting from the end-user demand (bottom up). Model calculations occur annually and begin with electricity requirements from the demand sectors, labelled as Step 1. Electricity requirements include grid demand and industry demand satisfied by on-site facilities. The electricity demand and peak load requirements prompt the electricity supply system to respond. During Step 2, specified import targets are subtracted from the electricity demand and specified export targets are added to the electricity demand, according to specified import/export targets. The net electricity requirement is then passed to Step 3.

During Step 3, the required electricity system total capacity is determined and the corresponding technology-specific capacity expansion and generation are determined. The technologies to undergo capacity expansion and dispatch are determined through a combination of exogenous inputs and endogenous calculations, depending on the scenario. Plant dispatch is governed by the technical and economic characteristics of each technology, the system energy load shape, and the dispatch rules of the system. On-site plants dispatch electricity to fulfil on-site requirements and export electricity to the provincial grid. Producer consumption occurs alongside electricity generation to fulfil plant electricity requirements.

Feedstock fuels (Step 4) are produced to satisfy electricity generation processes. Step 4 was included to provide upstream emissions. During Step 5, the generated electricity from Step 3 is transmitted to fulfil the export requirements and demand sectors. Transmission losses also occur during this step. Grid transmission and distribution losses are assumed to occur at 3.6% of electricity generated based on historical data (AESO, 2019a).

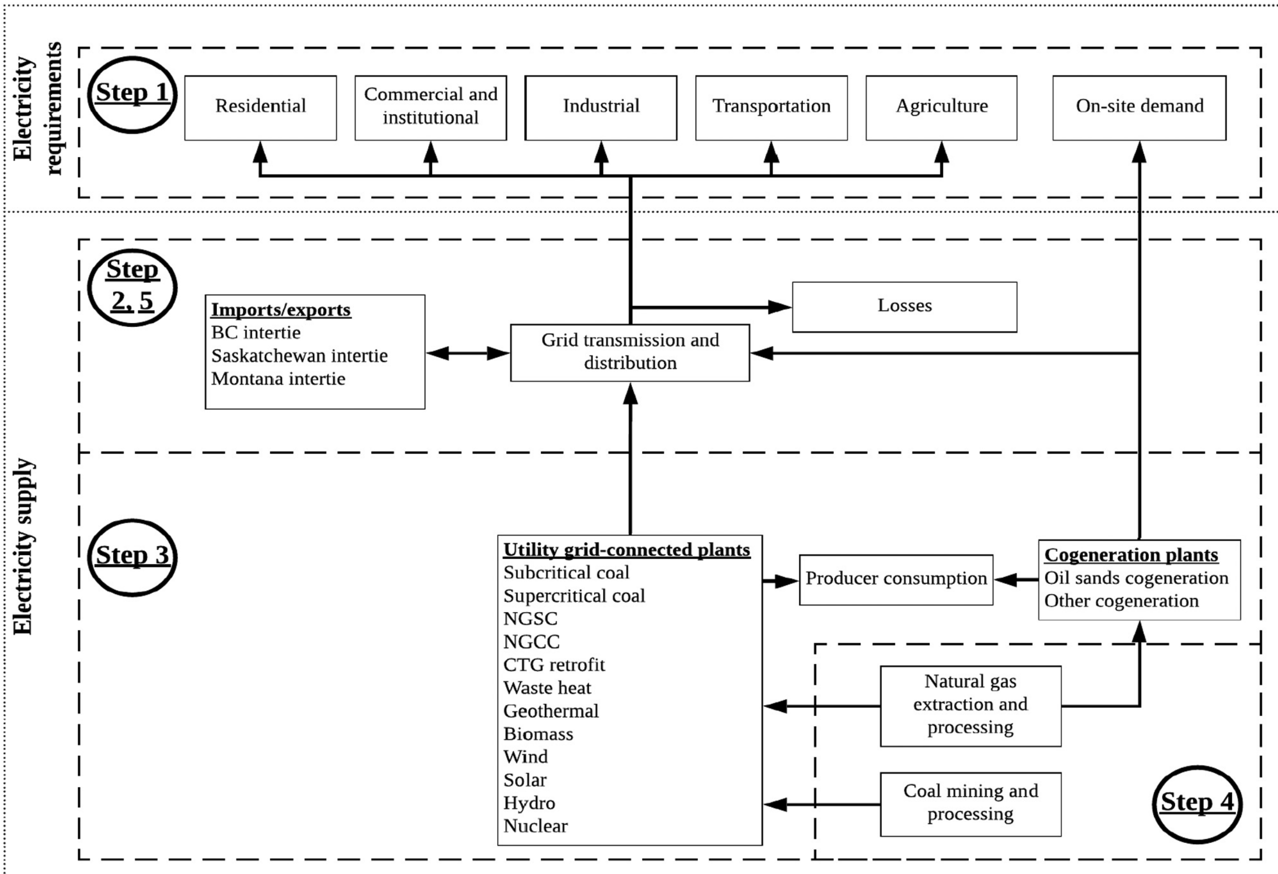

Fig. 3. LEAP-AES electricity model conceptual diagram.

Electricity requirements

Bottom-up demand projections for Alberta were developed in earlier work by one of the authors and take into account updated (as of 2019) economic, energy efficiency, and industry production expectations during the 2019–2050 study period. Since projecting electricity demand is not the focus of this work, the reader is referred to the earlier work for a detailed account of the methods used (Davis et al., 2018; Katta et al., 2019; Kumar Katta, Davis, & Kumar, 2020). Macroeconomic indicators were updated for this study; the values are shown in Table 1. The electricity requirements vary between peak and non-peak times and this variation is approximated by using Alberta-specific system energy load shapes that specify electricity load in hourly time steps, averaged into 8 seasonal day and night time slices. The system energy load shape was based on 2016 hourly load data (the most recent dataset available) (AESO, 2016). The corresponding annual electricity requirements and peak power requirements are also given in Table 1.

Table 1
Key activity variables for Alberta electricity demand.

	2015	2020	2030	2040	2050
Population (million)	4.2	4.5	5.3	5.9	6.5
GDP (billion $2007 Canadian dollars [CAD])	314	338	415	491	573
Households (thousands)	1,534	1,670	1,985	2,261	2,542
Commercial floor space (million m^2)	110	120	146	176	208
Bitumen and SCO production (thousand barrels per day)	3,374	4,580	5,372	5,743	5,949
Total (GWh)	78	87	97	103	107
Peak load (GW)	9.7	10.8	12	12.7	13.1

Electricity supply

Electricity system capacities. Historical electricity capacities for all technologies were used in the model from 2005 to 2018 (AUC, 2018). For scenario years 2019–2050, the system capacity is determined by LEAP from Eq. (1). Firm capacity refers to capacity that can reliably produce electricity as determined by a capacity credit variable. A capacity credit value of 100% means the capacity is reliable and is fully attributed to the firm capacity. Capacity credit values for each electricity generation process are given in Table 2. Capacity credit values for wind were specifically set to correspond to the share of wind generation in the total system generation. For the business-as-usual scenario, this value was set to 22% (corresponding to ~5% wind generation) and for alternative scenarios the value was set to 7.1% (corresponding to >35% wind generation) (GE Energy Consulting, 2016). A 15% planning reserve margin was assumed for the study period.

$$\begin{aligned} \textit{Firm system capacity} &= \textit{Peak load}*(\textit{Planning reserve margin}+1) \\ &= \textstyle\sum_x^n \textit{Capacity}_{Tech\_x} * \textit{Capacity Credit}_{Tech\_x} \end{aligned} \tag{1}$$

To fulfil the firm capacity during scenario years, the residual firm capacities from the previous year and the exogenously specified firm capacities are first allocated. Exogenously specified capacities across all scenarios exist for existing capacities as of 2019 and follow a retirement schedule given in the Appendix. With residual firm capacities from the previous year and the exogenously specified firm capacities allocated, capacity additions for renewable and nuclear technologies occur endogenously through OSeMOSYS to meet the system requirements according to scenario specifications in the Scenario formulation section. Capacity addition constraints are given in Table 2. The maximum

Table 2
Electricity supply process inputs.

Process	Process efficiency (%)	Maximum availability (%)	Capacity credit	Overnight capital cost ($2017 CAD/kW)	Plant size (MW)	Maximum annual addition (MW)	Fixed O&M ($2017 CAD/kW per year)	Variable O&M ($2017 CAD/MWh)	Lifetime (years)
Subcritical coal	32	72	100	n/a	n/a	n/a	35	7	n/a
Supercritical coal	40	72	100	n/a	n/a	n/a	36	7	n/a
Cogeneration	60–65	70	100	1290	85	400	15	4	30
NGCC	52–60	82	100	1259	479	479	50	3	20
NGSC (Aeroderivative)	35.2	84	100	1359	93	279	53	1	20
NGSC (Frame)	33.9	84	100	616	243	243	26	5	20
CTG retrofit	32	72	100	225	368–406	368–406	22	4	15
Hydro	n/a	56	75	4106	100	2000	18	4	40
Wind	n/a	33–42	22–7	1928–1000	100	600	37–30	0	25
Utility scale solar PV	n/a	16–20	0	1650–800	15	600	25–23	0	25
Existing biomass	n/a	56	100	n/a	n/a	n/a	n/a	n/a	n/a
Biomass forest-residue	32	70	0	2383	200	400	67	58	30
Biomass straw	32	70	0	2573	200	400	74	53	30
Waste heat	n/a	41	100	n/a	n/a	n/a	n/a	n/a	n/a
Nuclear	32	90	100	7959	2234	2234	135.2	12.4	60
Geothermal	n/a	90	100	6929	50	100	120	0	30
BC intertie restoration	n/a	71	100	1271	400	400	239	50	50
BC Site C	n/a	52	100	9772	1100	1100	30	7.5	70

capacity of oil sands cogeneration was assumed to grow at the same pace as projected bitumen production with an elasticity of 0.76. Elasticity was determined from 2005 to 2017 total bitumen and SCO production and total oil sands cogeneration capacity. Other cogeneration capacity was maintained at 2018 levels as growth is expected to be limited (AESO, 2019b). Other capacity addition constraints include plant size constraints, which corresponds to the assumed capital costs, and maximum annual additions, which are assumed based on historical ranges achieved in Canada. Additional scenario-specific constraints such as maximum and minimum capacities are described in the Scenario formulation section.

Electricity system generation. Electricity generation dispatch meets demand through a lowest cost offer sequence. This is simulated in LEAP-AES through a yearly system energy load shape and a least-cost dispatch sequence using LEAP's OSeMOSYS to determine the generation from each technology. Least-cost to higher-cost technologies are dispatched up to their maximum availability on a sequential continuum to fulfil electricity requirements. The average maximum availability values for each technology, assumed based on Canada's historical and expected future ranges (AESO, 2019b, 2019c; AUC, 2018; CER, 2019), are given in Table 2. Ranges represent expected improvements realized by 2050. The maximum availability for wind was modelled with a supply curve based on historical wind generation data from the Alberta Electric System Operator (AESO) (AESO, 2018). Utility-scale solar photovoltaic (PV) was also modelled with a supply curve by assuming output only during daytime hours.

Electricity system GHG emissions. Fossil fuel combustion from electricity generation and fuel production and processing emissions are determined by applying emission factors within the LEAP model. A CO_2e emission factor for coal-based power production was derived from Alberta facility-specific emissions (Government of Canada, 2018) and electricity generation data (AUC, 2018). Coal-based electricity generation emissions averaged 996 t/GWh between 2005 and 2016; this figure is used for the years 2017–2030. Natural gas-based electricity generation emissions are calculated by applying LEAP's Technology and Environmental Database (TED) Tier 1 IPCC emission factors to the amount of natural gas combustion. The associated global warming potentials are derived from the IPCC 5th Assessment (IPCC, 2013). Feedstock fuel requirements were determined by the amount of electricity generation and the process efficiency variable, given in Table 2. Process efficiencies were assumed based on ranges published in (AESO, 2019b; EIA, 2017; IEA, 2017; JEM Energy, 2004; The Brattle Group, 2018) and calibrated with historical fuel input data to account for producer consumption by each technology (Statistics Canada, 2018); ranges represent 2019–2050 values. The process efficiency of cogeneration considers the electricity output, portion of input fuel used to produce electricity, and fuel savings due to cogeneration of electricity and steam compared to using a stand-alone boiler for steam generation (EPA, 2017). Emissions from biomass combustion were assumed to be carbon neutral.

Electricity system costs. Assumed costs for coal and cogeneration (AESO, 2012; The Brattle Group, 2011), natural gas combined cycle (NGCC) and natural gas simple cycle (NGSC) (The Brattle Group, 2018), coal-to-gas (CTG) retrofits (AESO, 2017), hydro (The Brattle Group, 2011), biomass (Kumar, Cameron, & Flynn, 2003; Thakur, 2010), nuclear (EIA, 2019a, 2019b; NREL, 2010), and geothermal (EIA, 2019b; Geoscience BC, 2016) are shown in Table 2.

The geothermal capital cost is the weighted average of costs from sites studied in (Geoscience BC, 2016). Assumed costs and baseline cost reductions for wind and solar are founded on projected growth of investment, technology learning rates, and technology improvements (Alberta Electric System Operator, 2019; AWS Truepower, 2018; CER, 2019). Two hydroelectricity supply options from the neighboring province of British Columbia (BC) were also included. The BC Site C dam (BC Hydro, 2017) is a 1100 MW hydropower project currently under construction and the BC intertie restoration increases the capacity of the existing intertie (AESO, 2015; CERI, 2016). The variable O&M for the intertie is assumed to equal the average electricity pool price (AESO, 2019c). Variable O&M includes fuel costs for biomass and nuclear. Natural gas fuel price projections (Table 3) were taken from the Canadian Energy Regulator (CER) (CER, 2019) up to 2040 and linearly extrapolated to 2050 based on the 2035–2040 growth. The coal price is for mine-to-mouth costs of coal production (The Brattle Group, 2011). All capital costs include a standard plant transmission and interconnection costs. Carbon pricing follows a “good-as-best-gas” system (Government of Alberta, 2019). Under this regulation, the carbon price is charged to facilities exceeding the benchmark carbon intensity. The carbon price at the time of this writing is $30/t$CO_2$e. The federal government has announced it will implement a backstop reaching $50/t$CO_2$e by 2022; however, it is currently unclear if this will replace the current Alberta price so $30/t is taken as the baseline condition and changes

Table 3
Fuel costs (real \$2017 CAD/GJ).

Year	2015	2020	2030	2040	2050
Natural gas	2.4	1.4	3.2	3.8	4.4
Coal	1.1	1.1	1.1	n/a	n/a

to the carbon price is included in the alternative scenario conditions analysis. Details on carbon pricing can be found in Table 4.

$$\textit{Fraction of Tech\_x emissions subject to carbon pricing} = 1 - \frac{benchmark_{n,Tech\_x}\left[\frac{CO_2e}{MWh}\right]*generation_{n,Tech\_x}[MWh]}{emissions_{n,Tech\_x}\,[CO_2e]} \quad (2)$$

Scenario analysis

The scenario analysis involved formulating scenarios, implementing the scenarios in the LEAP model, and conducting a cost-benefit analysis on the results. A business-as-usual (BAU) scenario and 21 alternative technology expansion scenarios (described in the Technology expansion assumptions section) were developed and each were run through a baseline set conditions (data inputs described in the Development of the Alberta electricity system model section) and alternative conditions covering different future energy demands, energy and carbon prices, technology costs, renewable generation targets, and deployment speeds (described in the Alternative scenario conditions section) giving 382 total scenarios. The method used to conduct the cost-benefit analysis is covered in the Cost-benefit analysis section.

Scenario formulation

Technology expansion assumptions. The technology expansion assumptions allow for the growth of specific renewable electricity generation technologies depending on the scenario. Table 5 provides the key assumptions for each scenario and mentions how they differ from baselines described in the Development of the Alberta electricity system model section. For each alternative scenario, NGSC, NGCC, and wind technologies have no maximum capacity constraints. The high end of estimates for wind capacity potential in Alberta range from ~58–150 GW (Barrington-Leigh & Ouliaris, 2017; SOLAS Energy Consulting Inc., 2013; The Pembina Institute, 2009) and it is not expected that that would be reached in any future scenario given the electricity demand projections. Unless otherwise stated, new technology capacity additions begin in 2019. Scenarios were screened for feasibility in terms of renewable resource potential and practicality/likelihood of capacity expansion in Alberta. For all scenarios, it was assumed that transmission infrastructure keeps pace with requirements.

Alternative scenario conditions. It has been postulated that marginal abatement costs may become less accurate for longer-term assessments due to uncertainty of future technology and policy developments (Isacs et al., 2016). Given the long-term nature of the present study and the uncertainty of key future conditions in the modelling (energy demands, energy and carbon prices, technology costs, renewable generation targets, and deployment speeds), the scenarios described in Table 5 were modified using alternative scenario conditions (instead of baseline conditions presented in the Development of the Alberta electricity system model section) and also assessed. The alternative scenario conditions are summed up in Table 6. A lower and higher projection of electricity demand was evaluated by varying its growth by ±20% by 2050, closely in line with the high and low-growth scenario results from the AESO (AESO, 2019b). Future capital cost reductions of wind and utility solar PV were varied from 0% cost reductions to 30% and 50% below the baseline cost reductions by 2050, respectively. Average hydro and geothermal capital costs are also uncertain since they can vary largely depending on the sites being developed, these values were varied by ±30%. Fixed O&M costs of NGCC were analyzed since it makes up a relatively large portion of NGCC levelized costs and the estimates have varied widely in recent years from ~27–53 \$/MW (AESO, 2012, 2017, 2019b; The Brattle Group, 2018). The impact that it has was investigated by changing NGCC fixed O&M (50 \$/MW) by −50%. A low and high natural gas price forecast was also assessed based on the low and high price projections (CER, 2019). The impact of a higher maximum annual wind addition value was tested; the 600 MW assumed value is increased to 1000 MW, an annual capacity addition value that has been reached in Quebec and Ontario within the past decade (CER, 2019). Renewable generation targets of 30% by 2030 and 50% by 2050 were also evaluated. Finally, the carbon price was varied from \$30/tCO_2e to \$50/t (nominal), inline with the federal government of Canada's Pan Canadian Framework (Government of Canada, 2016), as well as reduced to \$0/t. The cumulative GHG mitigation and marginal abatement cost results for each scenario were evaluated for each condition mentioned above.

Table 4
Carbon pricing variables.

Year	2019–2050
Carbon price (\$/tCO_2e nominal CAD)	\$30/t in 2019, increases with inflation 2020–2050
Percent of emissions subject to carbon pricing	Eq. (2): n = year, $Tech\_x$ = electricity generation process
Benchmark (tCO2e/MWh)	0.37 1% annual decrease starting in 2020
Inflation (Statistics Canada, 2017)	2% per year

Cost-benefit analysis

The net present value (NPV) in 2017 for each scenario was determined by the LEAP model. The variables used to calculate NPV (Eq. (3)) are the annualized plant capital costs (ACC), fixed operating and maintenance cost (FOM), variable operating and maintenance costs (VOM), fuel cost (FC), externality (carbon) costs (EC), and discount rate (r); n is the year. The discount rate is assumed to be 5%. Annualized capital costs are determined with Eq. (4) from the overnight capital cost (CC), interest rate (i) and lifetime of the plant (L). The interest rate is assumed to be 5%. Decommissioning and indirect costs are not considered. Only the costs for the electricity system were considered for the cost-benefit analysis; upstream natural gas and coal production costs were not included. Costing of required transmission and distribution system modifications, such as upgraded import/export capability or new infrastructure (outside of connecting new plants to existing grid infrastructure) is also out of the scope of this study. Environmental and human health externalities of GHG emissions are also not in the scope.

Eqs. (3), (4), and (5) are used to calculate the marginal GHG abatement cost. The marginal GHG abatement cost is expressed in \$ per tonne CO_2 equivalent and is expressed mathematically as:

$$\mathrm{NPV} = \left[\sum_{n=1}^{N}(ACC_n + FOM_n + VOM_n + FC_n + EC_n)/(1+r)^{n-1}\right] \quad (3)$$

$$\mathrm{ACC} = \frac{i}{1-(1+i)^{-L}}*CC \quad (4)$$

$$\text{Marginal GHG abatement cost} = \frac{\mathrm{NPV}_S - \mathrm{NPV}_{BAU}}{\mathrm{GHG}_{BAU} - \mathrm{GHG}_S} \quad (5)$$

where NPV_{BAU} is the net present value of the BAU scenario, NPV_S is the net present value of an alternative scenario, GHG_{BAU} is the cumulative GHG emissions of the BAU scenario, and GHG_S is the cumulative GHG emissions of an alternative scenario.

Table 5
Scenario descriptions.

Scenario name	Description
BAU	The business-as-usual (BAU) scenario serves as a baseline for the cost-benefit analysis as well as for validation of the model. The renewable technology capacities, coal retirements, and CTG conversions are set to be in line with the reference projections in the 2019 AESO Long Term Outlook (LTO) report (AESO, 2019b). All other technology capacities are endogenously added/retired by the model and those results are compared to the 2019 AESO LTO reference scenario for model validation.
ECR WND CTG I	Early retirement and conversion of 2.4 GW of subcritical coal plants to natural gas between 2021 and 2023. NGCC, NGSC, and wind make up the remaining requirements.
ECR WND CTG II	Early retirement and conversion of 5.2 GW of subcritical coal plants to natural gas between 2021 and 2027. NGCC, NGSC, and wind make up the remaining requirements.
ECR WND COG I	A study by Layzell et al. proposed high-capacity penetration of cogeneration in Alberta oil sands as one means of reducing GHG emissions (Layzell, Narendran, Shewchuk, & Sit, 2016). ECR WND COG I assumes early retirement of 2.4 GW of subcritical coal plants and the option for replacement with natural gas cogeneration capacity between 2021 and 2023. NGCC, NGSC, and wind make up the remaining requirements.
ECR WND COG II	Early retirement of 5.2 GW of subcritical coal plants and the option for replacement with natural gas cogeneration capacity between 2021 and 2027. NGCC, NGSC, and wind make up the remaining requirements.
ECR WND	Early retirement of 5.2 GW of subcritical coal plants and NGCC, NGSC, and wind make up the remaining requirements.
WND	NGCC, NGSC, and wind expand as required to meet requirements.
WND HYD	In the WND HYD scenarios, hydro capacity reaches 3500 MW by 2030. This capacity is within the total capacity of previously identified potential high-quality hydropower sites (ATCO, 2015). Hydro continues to grow past 2030 and reaches 10,000 MW by 2050, well under the estimated developable potential for hydropower in Alberta of ~11–19 GW (Barrington-Leigh & Ouliaris, 2017; The Pembina Institute, 2009; Waterpower Canada, 2020; Hatch, 2010). NGCC, NGSC, and wind make up the remaining requirements.
WND GEO	Studies indicate that heat and electricity generation may be feasible in the Western Canadian Sedimentary Basin (WCSB) using enhanced geothermal systems (Hofmann et al., 2014; Majorowicz & Moore, 2014). Minimum and maximum potential estimates for geothermal generation in Alberta range from 4.2 GW to 555 GW with recovery at 5% and 20%, respectively (CanGEA, 2013). In these scenarios, geothermal capacity reaches 500 MW by 2030 and 1000 MW by 2050. Geothermal capacity expansions begin in 2022. NGCC, NGSC, and wind make up the remaining requirements.
WND BIO St	The potential for biomass-based generation capacity from uncollected straw in Alberta is about 2000 MW (Thakur, 2010). It is assumed that biomass power with straw feedstock reaches 1000 MW by 2030 and 2000 MW by 2040. Biomass capacity expansions begin in 2022. NGCC, NGSC, and wind make up the remaining requirements.
WND BIO FR	The estimated power generation potential for forest residue in Alberta is 1.2 GW (Thakur, 2010). It is assumed that the penetration of biomass power with forest residue feedstock reaches 800 MW by 2030 and 1200 MW by 2040. Biomass capacity expansions begin in 2022. NGCC, NGSC, and wind make up the remaining requirements.
WND BIO StFR	Capacity potential for both straw and forest residue feedstock is realized in WND BIO St and FR. Biomass capacity expansions begin in 2022. NGCC, NGSC, and wind make up the remaining requirements.
WIND SOL Ut	Utility solar capacity expands to a minimum of 5000 MW by 2040 and 10,000 MW by 2050. The choice of 5000 and 10,000 MW is arbitrarily chosen such that a large portion of expected system capacity will contain solar power. The 2019 AESO LTO report (AESO, 2019b) projects total system capacity in year 2039 to be ~23,000 MW, thus the assumed solar capacity expansion would give ~20% solar. Estimates for solar power potential range roughly between 50– 5000 GW (Barrington-Leigh & Ouliaris, 2017; Jacobs Consultancy, 2014), thus the assumed capacity expansions are well under the potential. NGCC, NGSC, and wind make up the remaining requirements.
WND BIO HYD	This scenario combines the WND BIO StFR and WND HYD assumptions for biomass and hydro, respectively.
WND BIO SOL	This scenario combines the WND BIO StFR and WND SOL Ut assumptions for biomass and solar, respectively.
WND HYD SOL	This scenario combines the WND HYD and WND SOL Ut assumptions for biomass and solar, respectively.
WND HYD SOL BIO	In this scenario, high penetration of all renewables is assumed. Biomass penetrates as in the WND BIO StFR scenario, hydro penetrates as in the WND HYD scenario, solar penetrates as in the WND SOL Ut scenario, and NGCC, NGSC, and wind make up the remaining requirements.
WND BC INT	This scenario imports BC hydropower by increasing the exiting intertie capacity between Alberta and BC. The intertie option would involve building upon existing intertie infrastructure to increase capacity by approximately 400 MW (AESO, 2015). The intertie is assumed to become operational in 2021. NGCC, NGSC, and wind make up the remaining requirements.
WND BCSC	This scenario uses the BC Site C dam (BC Hydro, 2017) (currently under construction) exclusively for imports to Alberta. The Site C dam has a design capacity of 1100 MW set to be completed in 2025. NGCC, NGSC, and wind make up the remaining requirements.
WND BC-INTSC	This scenario combines the BC Intertie and the BC-Site C scenario assumptions.
OPT	This scenario fully optimizes capacity additions considering all options. Upper capacity limits for biomass FR and St, BC intertie, and Site C are taken from the corresponding scenarios for those technologies. ECR and CTG conversions were not considered in this scenario.
WND NUC	Nuclear plants are added, one (2234 MW) by 2030 and a second by 2040, for a total of 4468 MW by 2040. NGCC, NGSC, and wind make up the remaining requirements.

Results and discussion

Model validation

Validation is an important first step in the analysis as it inspires confidence in the accuracy of the new model and reasonableness of future projections. The LEAP-AES model results for the BAU scenario were compared to government and regulatory historical and projection data on electricity demand, capacity, GHG emissions, and generation (AESO (AESO, 2019b), AUC (AUC, 2018), CER (CER, 2019), Environment and Climate Change Canada (ECCC, 2018), and CANSIM (Statistics Canada, 2019). Fig. 4 illustrates the validation results and clearly shows that the model outputs for historical and future projections are within reasonable ranges compared to statistical and government data. Electricity demand results (2005–2050) are on par with the available data from AESO with differences of no more than 2.4%. Data discrepancies between the official sources can be as much as 12%. Thus, electricity demand projections are considered a reasonable prediction of system demand. Electricity capacity results compared to AESO projections differ only slightly until 2039, where LEAP-AES capacity is reduced and AESO capacity is not. This is likely due to the assumed retirement schedule and capacity addition constraints differing between the LEAP-AES model and AESO model. Additionally, a target reserve margin of 15% is reached between 2040 and 2050 in the LEAP-AES as plants are retired (mostly the CTG plants), where as in the AESO results, a reserve margin of 26.5% is reached. Electricity generation differences reach a 4% difference between LEAP-AES and AUC/AESO data, although, there is a 9.3% difference between historical data sources (AUC, AESO, NEB, and Statistics Canada). Technology-specific validation charts are shown in the Appendix. GHG emission results were compared to NIR data. This is not a completely appropriate comparison, as industry-owned electricity generation emissions are not accounted for in the NIR electricity generation total and there is a large portion of unallocated electricity. Still, the absolute average difference in values is only 3.2% from 2005 to 2016 with maximum differences of 9.4% in 2008. A validation of emission factors, including upstream emissions, is given in the Appendix.

Table 6
Summary of assumptions for alternative scenario conditions.

Variable	Alternate assumptions
Electricity demand	a) Annual incremental change starting in 2019 reaching 20% below baseline demand in 2050
	b) Annual incremental change starting in 2019 reaching 20% above baseline demand in 2050
Capital cost reductions of wind	a) No cost reductions from 2019 onward
	b) Further 30% cost reductions by 2050 compared to baseline
	c) Further 50% cost reductions by 2050 compared to baseline
Capital cost reductions of utility solar PV	a) No cost reductions from 2019 onward
	b) Further 30% cost reductions by 2050 compared to baseline
	c) Further 50% cost reductions by 2050 compared to baseline
Average hydro capital costs	a) 30% decrease of baseline value
	b) 30% increase of baseline value
Average geothermal capital costs	a) 30% decrease of baseline value
	b) 30% increase of baseline value
NGCC fixed O&M	a) 50% decrease of baseline value
Natural gas price forecast	a) Low price forecast (CER, 2019) used up to 2040. Linear extrapolation for 2041–2050 based on 2035–2040 data
	b) High price forecast (CER, 2019) used up to 2040. Linear extrapolation for 2041–2050 based on 2035–2040 data
Maximum annual wind addition value	a) Change from 600 MW to 1000 MW
Renewable generation policy targets	a) 30% renewable generation (inclusive of nuclear) by 2030 required
	b) 50% renewable generation (inclusive of nuclear) by 2050 required
Carbon price	a) Increased to \$50/tCO_2e (nominal) from the \$30/t baseline
	b) Decreased to \$0/tCO_2e from the \$30/t baseline

BAU scenario

The business-as-usual (BAU) scenario serves as baseline values for all other scenarios to be compared against. Fig. 5 illustrates the relevant results in terms of electricity generation capacity, generation, GHG emissions, and the emission factor. Coal capacity is eliminated by 2030, as shown in the upper left chart, and ~4.8 GW of the coal capacity is converted to natural gas (CTG conversion). NGCC capacity has the largest amount of growth, from 1750 MW in 2019 to 6000 MW by 2040. Generation from NGCC surpasses generation from NG cogeneration after 2040 and makes up 38% of the generation mix by 2050. Wind capacity expands to 5000 MW by 2040, from 1475 MW in 2019 and generation from wind increases to 18 TWh by 2050, making up 18% of the generation mix. Limited growth is seen for other renewables.

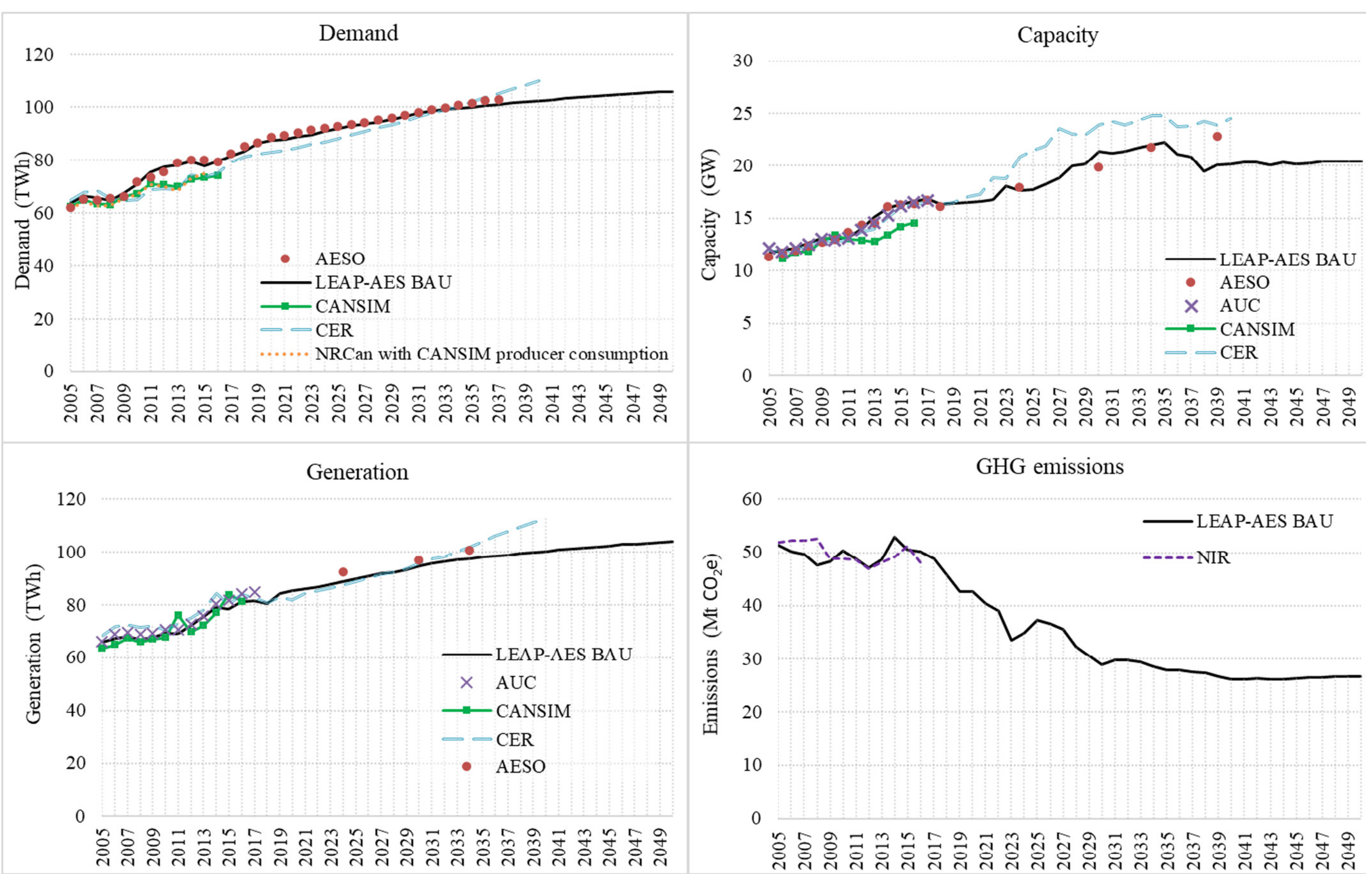

Fig. 4. Validation results for electricity demand (upper left), capacity (upper right), generation (bottom left), and GHG emissions (bottom right).

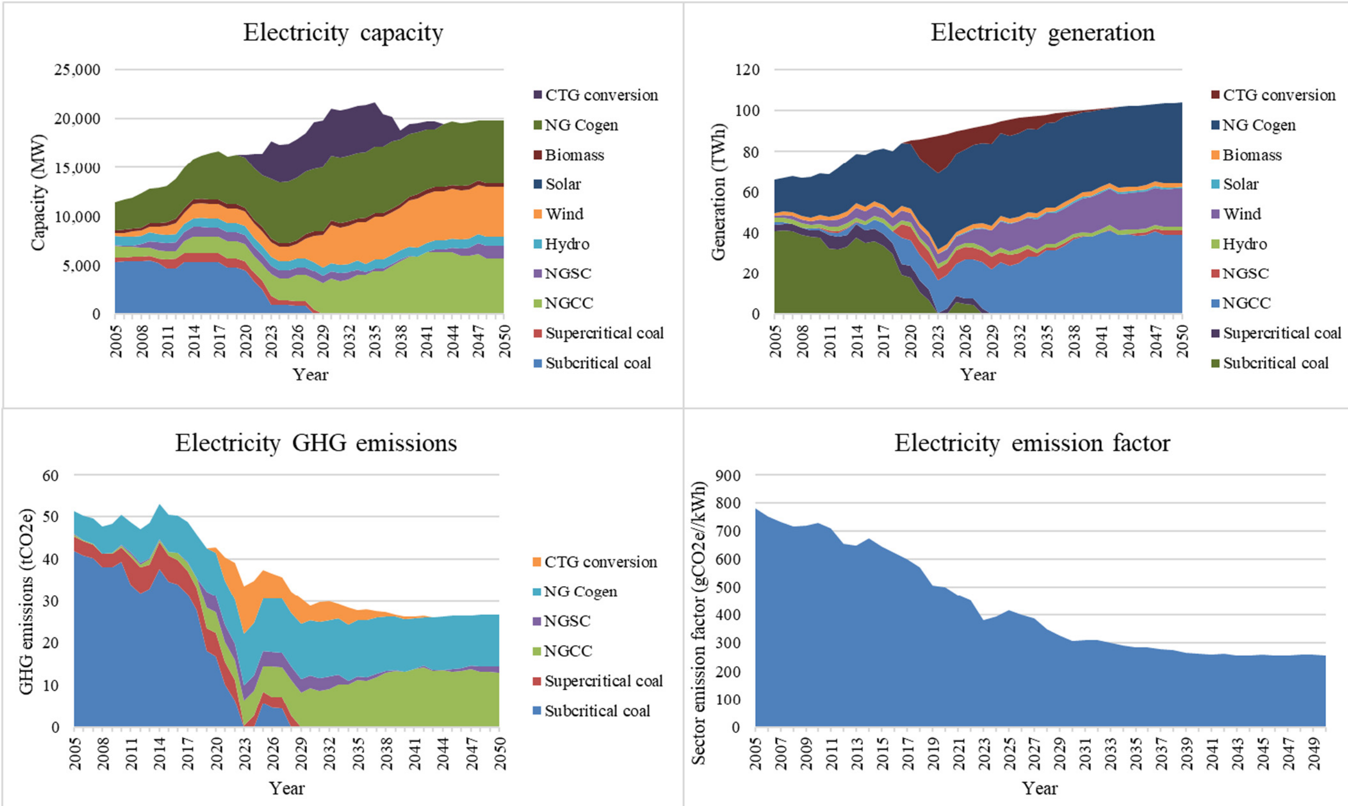

Fig. 5. Business as usual scenario results for electricity capacity (upper left), generation (upper right), GHG emissions (bottom left), and sector emission factor (weighted average considering sector-wide electricity generation mix, bottom right).

As coal generation is reduced, 32% of GHG emissions are eliminated by 2030. NG cogeneration and NGCC emissions make up the majority of emissions between 2030 and 2050; total GHG emissions only decrease by 8% during that time, also reflected by the emission factor remaining relatively stable after 2040.

Scenario analysis

Technology mix results

Figs. 6 and 7 show the technology mix shares for the electricity system capacity and generation for each of the baseline scenarios. The BAU scenario can be found on the bottom of each chart and used to compare the changes to technology mixes across scenarios. Cogeneration capacity is relatively consistent across scenarios in 2030, save for the ECR WND CTG I and II scenarios where cogeneration increases to over 50% of system capacity, compared to ~30% in 2019. By 2050, the cogeneration electricity generation share is reduced across the scenarios largely displaced by renewables and by NGSC. NGSC capacity increased by more than double between 2030 and 2050 in many scenarios as variable output renewables increase. Generation from cogeneration is reduced by 2050 from the scenarios with large capacity expansion of renewables, such as WND HYD SOL BIO, WND HYD SOL, WND HYD, and WND BIO HYD scenarios. Capacity from NGCC is substantially reduced in all scenarios (except for BAU) between 2030 and 2050 as new capacity addition requirements are fulfilled by renewables instead. Most of the growth in renewables happens between 2030 and 2050. The main reason behind these results can be attributed to both the declining costs of wind and solar, and new capacity requirements from electricity demand growth and plant retirements.

The fully optimized scenario (OPT) optimized for system costs across all possible renewable technology choices (does not consider ECR options). The resulting capacity mix by 2050 is made up of primarily wind (48%), cogeneration (25%), NGSC (11%), NGCC (8%), hydro (5.5%), and solar (2%). The wind capacity annual capacity addition upper constraint was reached in many years from 2027 to 2050 and total wind capacity reached 14 GW by 2050.

In many scenarios, wind power reached its upper maximum annual capacity addition constraints of 600 MW throughout the study period. The highest wind capacity generated across all scenarios was 15 GW, which generated 55 TWh in 2050. These figures are significantly higher than 2019 levels of wind-based power, but feasible Alberta wind power potential reported in the literature ranges from 64 (The Pembina Institute, 2009) to 150 GW (SOLAS Energy Consulting Inc., 2013) and 169 (Barrington-Leigh & Ouliaris, 2017) to 410 (SOLAS Energy Consulting Inc., 2013) TWh/yr, indicating that the wind power projected is feasible, provided the required transmission infrastructure and grid integration is completed.

Cost-benefit analysis

In order to provide decision makers with a means to choose energy pathways for sustainable development, marginal abatement cost curves have been suggested in the literature as important tools used for decision making (Huang, Kuo, & Chou, 2016). These are important results as sector specific ranking of options to a common baseline can reliably inform policy makers on what abatement strategies would be most useful to achieve the goals of climate change mitigation (Jiang, Dong, Zhang, & Liang, 2020). Fig. 8 illustrates the marginal GHG emission abatement cost curve for the baseline electricity generation pathways assessed in this study. The figure gives a side-by-side comparison of each technology mix scenario, giving the cumulative GHG emission mitigation between 2019 and 2050 (width of the box) and the marginal GHG emission abatement cost (height of the box) compared to the reference scenario. The marginal abatement cost represents the cost per unit of GHG emission abatement and marginal abatement cost curves illustrate these results graphically to quantify and compare the options for GHG emission abatement simultaneously. The figure directly

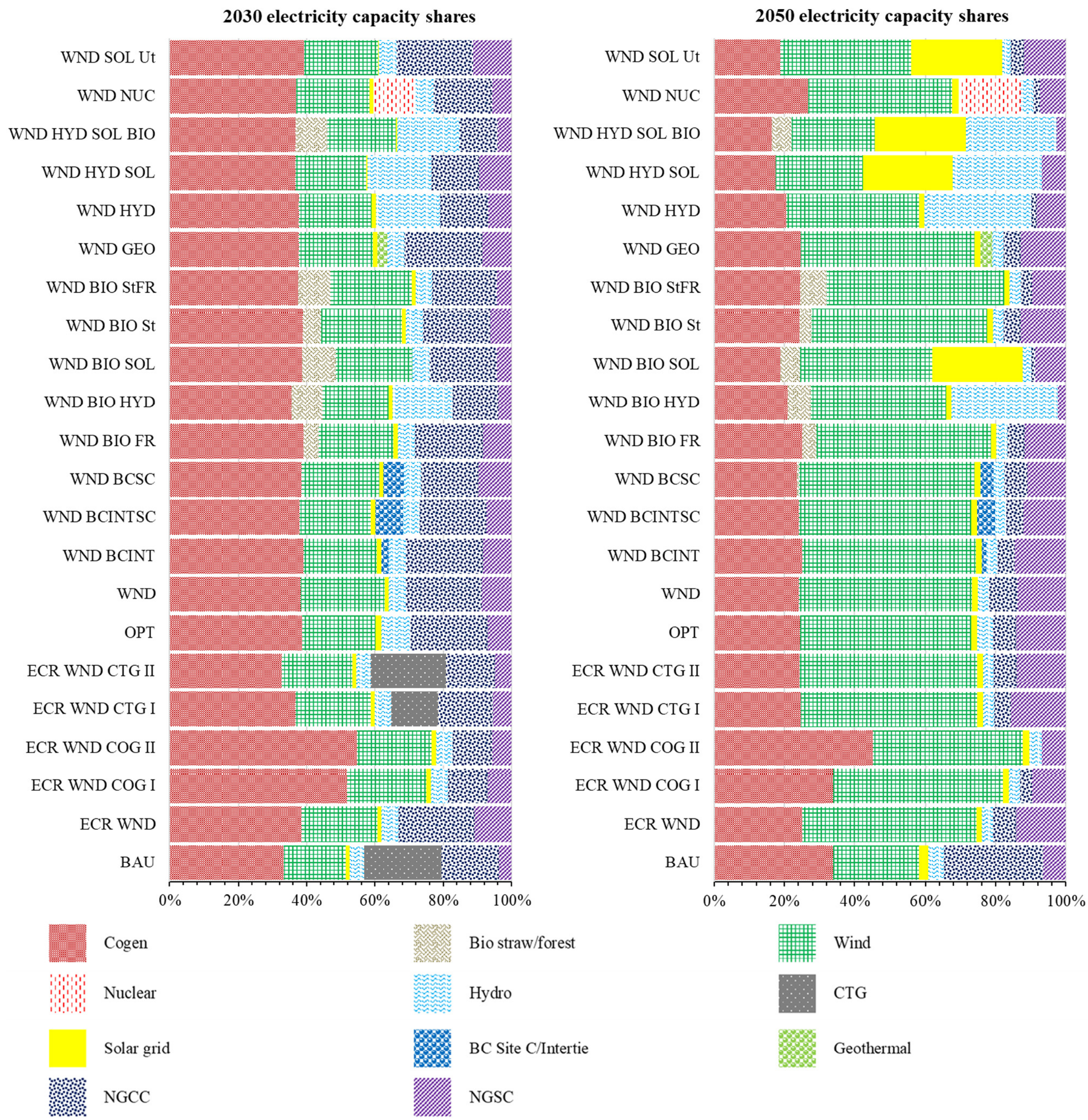

Fig. 6. Electricity capacity mix in year 2030 and 2050 for baseline scenarios (the appendix contains associated data tables).

shows the potential of emission reduction and what costs would be incurred with each pathway, and if emission reductions can be made at a net cost savings, the scenario is shown on the bottom of the x-axis. Additional results of the scenario analysis with baseline conditions are summarized in Table 7 where the 2030 and 2050 results for renewable generation, GHG emissions, and system costs are given.

Fifteen of the twenty-one baseline scenarios produce system cost savings compared to the BAU, with marginal GHG abatement costs ranging from -\$25.1 to \$14.8/t of CO_2e, with a median of \$-7/t. Marginal GHG mitigation with respect to the reference scenario ranged from 14% to 27%, with a median of 19%. The early coal retirement scenarios (ECR WND COG I, ECR WND COG II, ECR WND CTG I, ECR WND CTG II, ECR WND) make up 5 of the 6 least costly GHG emission mitigation scenarios shown. The scenarios that involve ECR resulted in 15–19% GHG mitigation vs the reference and marginal costs between −25.1 and −\$11.6/t with ECR-cogeneration scenarios having the lowest marginal GHG emission abatement costs across all scenarios, and ECR WND having the most GHG emission mitigation across the ECR scenarios. The fully optimized system has the lowest NPV (excluding scenarios with ECR) and reaches 23% renewable generation by 2030 and 60% renewable generation by 2050.

The wind-based scenario (WND) results in the second-least expensive scenario non-ECR, after the OPT scenario. The scenarios that integrate other renewables with WND are more costly but mitigate higher amounts of GHG emissions. The wind-biomass scenarios (WND BIO FR, WND BIO St, WND BIO StFR), wind-geothermal scenario (WND GEO), and wind-BC hydro import scenarios (WND BCINT, WND BCSC, WND BCINTSC) still resulted in a large expansion of wind power capacity since the capacity potential for these alternatives technologies is relatively small. The costliest among these are

Fig. 7. Electricity generation mix in year 2030 and 2050 for baseline scenarios (the appendix contains associated data tables).

the pathways involving the BC's Site C hydropower, the others have negative abatement costs. The AB-based hydro scenario (WND HYD) and wind-solar scenario (WND SOL Ut) are more favorable as they mitigate larger quantities of GHG emissions with negative marginal abatement costs. The wind-nuclear scenario resulted in the costliest marginal abatement cost but had the highest cumulative GHG mitigation.

The scenarios that combined expansion of more than two renewable options (WND HYD SOL, WND BIO HYD, WND BIO SOL, WND HYD SOL BIO) resulted in less favorable costs compared to other scenarios but have higher GHG emission mitigation. Of these, the scenario that combined wind, solar, and hydro is the only one with a negative abatement cost (Table 7).

Alternative scenario conditions

Each of the baseline scenarios presented in the last section were analyzed under baseline conditions (baseline energy prices, technology costs, electricity demands, and climate policies). Figs. 9 to 19 illustrate how the key result indicators (GHG mitigation and marginal GHG abatement costs) corresponding to the input variable change.

Fig. 9 shows the impact of lower and higher natural gas prices in line with CER projections (CER, 2019). Natural gas prices affected cumulative GHG mitigation most significantly for the scenarios with early coal retirements, and especially those where coal retirements were converted to gas plants. This occurred because with less expensive fuel, coal-to-gas plants were dispatched more often instead of building new natural gas plants, and since coal-to-gas plants have lower efficiencies than the other natural gas-fueled technologies, this resulted in higher emissions. Since many of the other scenarios had minimum levels of achieved renewable capacity growth, the natural gas price change did not significantly impact the mitigation results. Interestingly, the GHG mitigation results for the fully optimized scenario (OPT) did not reduce substantially with lower natural gas prices, indicating that high penetration of renewables remains cost-effective in the face of the low natural gas price forecast. The impact that the natural gas price had on the marginal abatement cost was consistent in that an average change of plus or minus \$9/tCO_2e was found across scenarios, with low and high natural gas prices, respectively, with a standard deviation of \$3/tCO_2e.

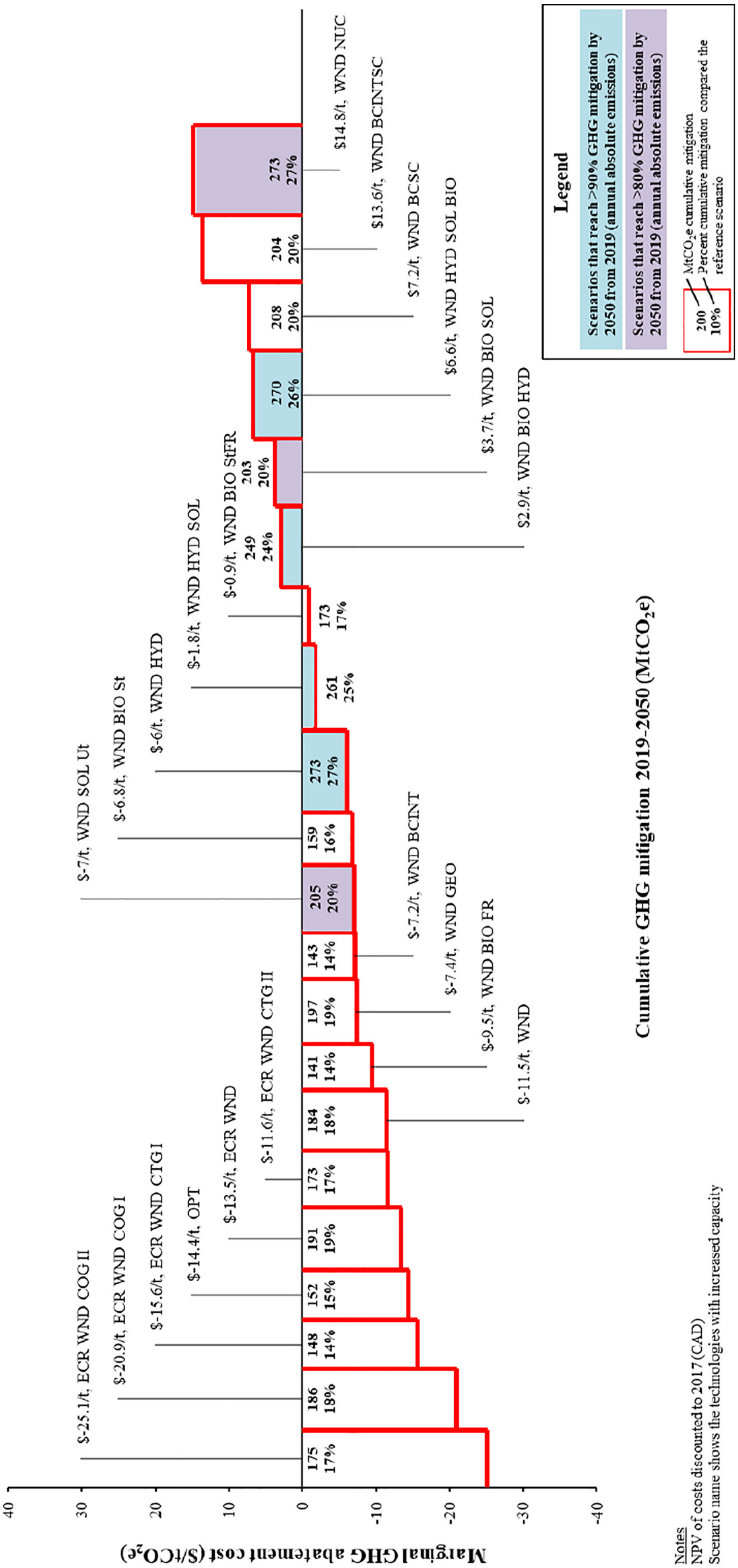

Fig. 8. Marginal GHG abatement cost curve for Alberta renewable electricity scenarios.

Table 7
Scenario analysis results.

	Renewable generation (%)		Absolute GHG emissions (Mt CO_2e)		Reduction from 2005 GHG emissions (%)		Sector-wide emission factor (g CO_2e/kWh)		Marginal NPV @ 5% discount rate (2017 CAD)		Cumulative GHG mitigation (tCO_2e)		Marginal GHG emission abatement cost (\$/tCO_2e)	
Scenario	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
BAU	18	22	29	27	44	49	306	257	0	0	0	0	0	0
ECR WND	22	58	26	14	49	73	278	134	−1149	−2574	56	191	−21	−13
ECR WND COG I	23	56	25	14	52	73	266	138	−1717	−3898	43	186	−40	−21
ECR WND COG II	22	46	25	17	52	67	263	167	−1772	−4404	65	175	−27	−25
ECR WND CTG I	23	59	27	14	47	74	289	130	−973	−2312	13	148	−76	−16
ECR WND CTG II	23	60	27	13	48	75	285	127	−755	−2015	33	173	−23	−12
OPT	24	59	25	14	52	74	266	131	−800	−2195	16	152	−49	−14
WND	23	58	26	14	51	74	271	132	−766	−2116	36	184	−21	−11
WND BCINT	21	58	27	14	49	73	282	133	−131	−1039	9	143	−15	−7
WND BCINTSC	27	63	25	12	53	76	260	118	1387	2789	33	204	42	14
WND BCSC	28	64	25	12	53	77	261	113	601	1492	35	208	17	7
WND BIO FR	23	59	27	13	49	74	281	130	−783	−1341	7	141	−109	−10
WND BIO HYD	36	93	21	2	59	96	223	20	−578	724	−6	249	102	3
WND BIO SOL	25	75	25	8	52	84	265	79	−717	747	7	203	−101	4
WND BIO St	24	60	26	13	51	75	271	126	−722	−1087	11	159	−64	−7
WND BIO StFR	26	61	25	13	52	76	262	122	−629	−158	15	173	−43	−1
WND GEO	25	65	25	11	52	78	265	109	−671	−1455	30	197	−23	−7
WND HYD	35	93	21	2	59	96	227	22	−860	−1496	9	251	−97	−6
WND HYD SOL	34	94	22	2	58	96	233	18	−903	−476	−6	261	150	−2
WND HYD SOL BIO	37	93	21	2	60	96	221	22	−665	1783	−8	270	78	7
WND NUC	40	78	19	7	63	86	205	69	−551	4053	20	273	−28	15
WND SOL Ut	21	74	27	8	48	84	284	81	−882	−1441	19	205	−46	−7

Fig. 10 shows the effect of hydropower cost variability. A decrease in the technology costs for hydro resulted in a large increase in the GHG mitigation potential for the optimized scenario due to increased deployment of the technology over natural gas. The cumulative GHG mitigation increased by 90% from the optimization scenario baseline. The other scenarios with hydro expansion increased their cumulative GHG mitigation from earlier expansion of the technology. Changes to marginal abatement costs due to ±30% changes in hydro capital costs resulted in ~±\$6.5/t change in scenarios involving high hydro expansion.

Fig. 11 shows the scenario results with different rates of capital cost decline for solar PV. The range shown extends from no decline in costs from 2019 values to a 50% less than baseline cost by 2050. There are no major changes to results when comparing to the baseline scenarios indicating that a more substantially reduced cost did not make the technology more favorable than wind and natural gas at the modelled performance levels.

Changes to the long-term capital cost reduction for wind-based power is shown in Fig. 12. Scenarios that consider no reduction in costs had a major impact on the GHG mitigation potential of all scenarios, indicating the favourability of wind power adoption over the study period. The assumed decline in wind capital costs is an important factor in the GHG abatement results of each scenario.

Nuclear power was considered in 2 scenarios, the optimized scenario and the wind-nuclear scenario (Fig. 13). A 30% reduction in nuclear power capital costs was not enough to result in the building of any nuclear power plants in the optimized scenario. There is only a notable change to the wind-nuclear scenario marginal abatement cost results, which changed by ±~70% compared to the baseline wind-nuclear scenario.

Fig. 14 shows scenario results compared to baseline for geothermal with 50% lower and 50% higher capital costs. The large range was chosen as there is not any commercially built plants in Alberta as of yet. Due to the limited maximum capacity assumed, the lower and higher geothermal costs did not greatly change the baseline results. The cumulative GHG mitigation of the wind-geothermal scenario with lower capital cost increased by 20% compared to the baseline scenario due to faster deployment.

The fixed operation and maintenance cost of natural gas combined cycle plants is also a key influencer of the GHG mitigation results, with 50% lower costs resulting in an average of 26% reduction in emission mitigation. Marginal abatement costs were less drastically influenced. Results across all scenarios can be found in Fig. 15.

Increasing the maximum annual wind capacity addition constraint from 600 MW to 1000 MW resulted in an average of 14% higher cumulative GHG mitigation (Fig. 16), indicating that the rate of wind development can play a large role in decarbonizing the sector. Earlier adoption of wind capacity led to less dispatch of natural gas over the study period, despite an addition of more natural gas simple cycle plants. There are not notable changes to the marginal abatement costs.

Fig. 17 shows the impact that changing the carbon price has on the scenarios. Moving from \$30 to \$50/t carbon price (top charts) resulted in an average GHG abatement decrease of 4% while a decrease to \$0/t resulted in 22% less abatement. Both resulted in an average decrease because, with a higher carbon price, the BAU also reduced emissions leaving less potential for GHG abatement. Marginal abatement costs are substantially lowered with the removal of any carbon price, however this comes at the expense of lower cumulative GHG mitigation overall for each scenario. If the BAU scenario is held at \$30/t and the scenario carbon pricing is varied to 0 and \$50/t (bottom two charts), a more consistent 34% decrease and 23% increase in GHG abatement is seen, respectively, with limited changes to the marginal abatement costs.

Renewable generation targets raised GHG mitigation by an average of 17% and 19% for the 30% and 50% renewable generation targets, respectively, as seen in Fig. 18. Only two scenarios had notable increases in marginal costs due to the 30% renewable target, the wind-cogeneration I and II scenarios, indicating that in most cases, the 30% target increased GHG mitigation without a corresponding increase in marginal abatement costs. The wind-cogeneration scenarios had increased marginal abatement costs from the 30% target because additional wind capacity was added earlier in the time period to meet the target. This increased cost compared to the scenarios with no target, where more wind capacity was added later rather than earlier in the time period. The 50% renewable target increased marginal abatement costs by an average of 27% compared to the baseline scenarios.

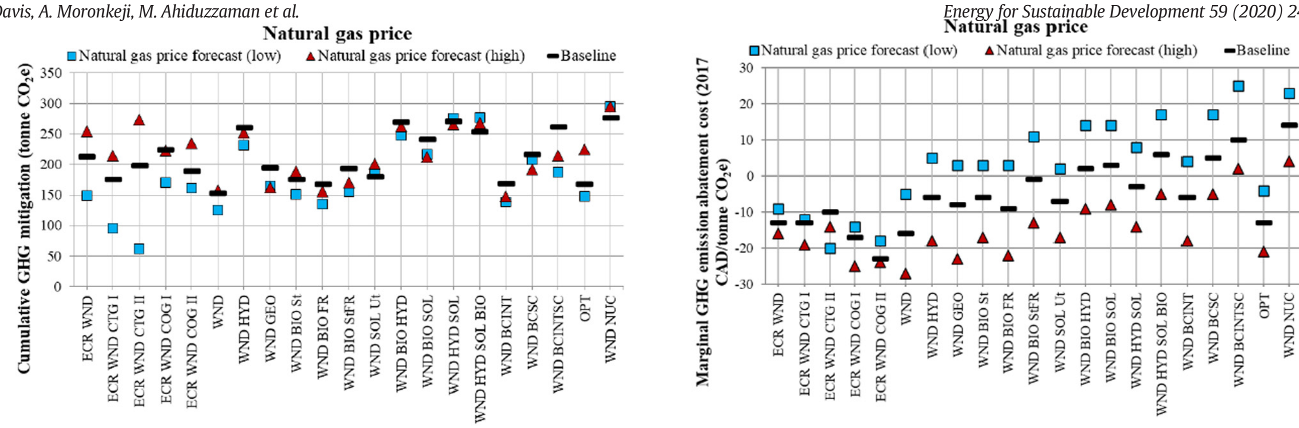

Fig. 9. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher natural gas price forecasts.

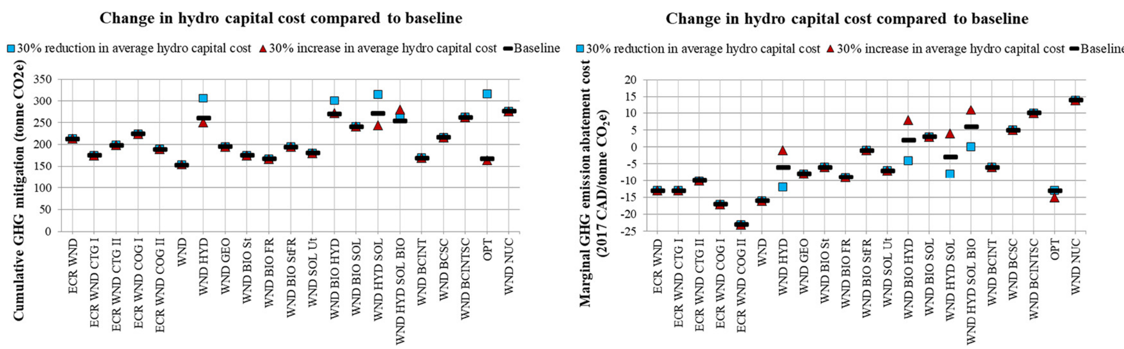

Fig. 10. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher hydropower capital costs.

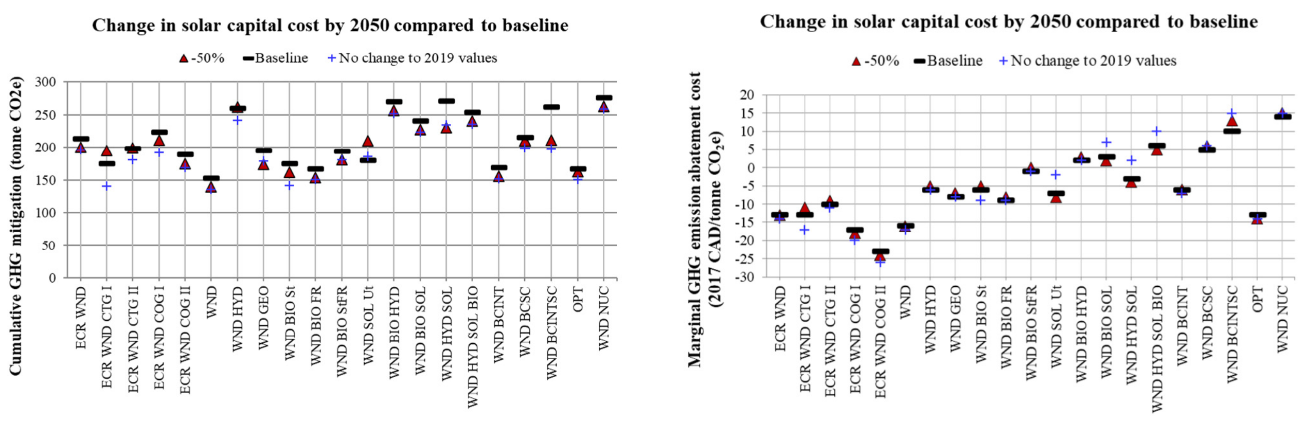

Fig. 11. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher solar PV capital costs.

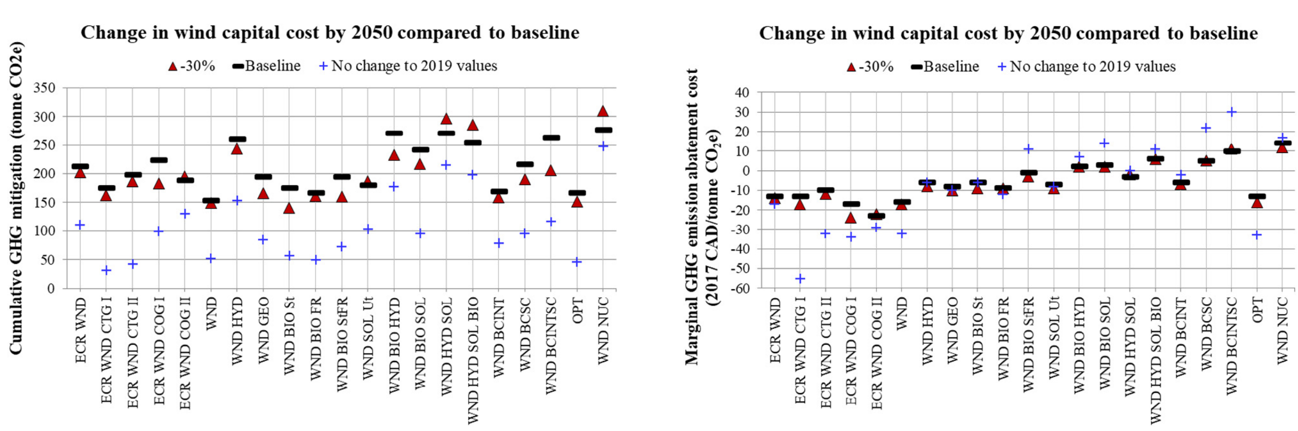

Fig. 12. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher wind-based power capital costs.

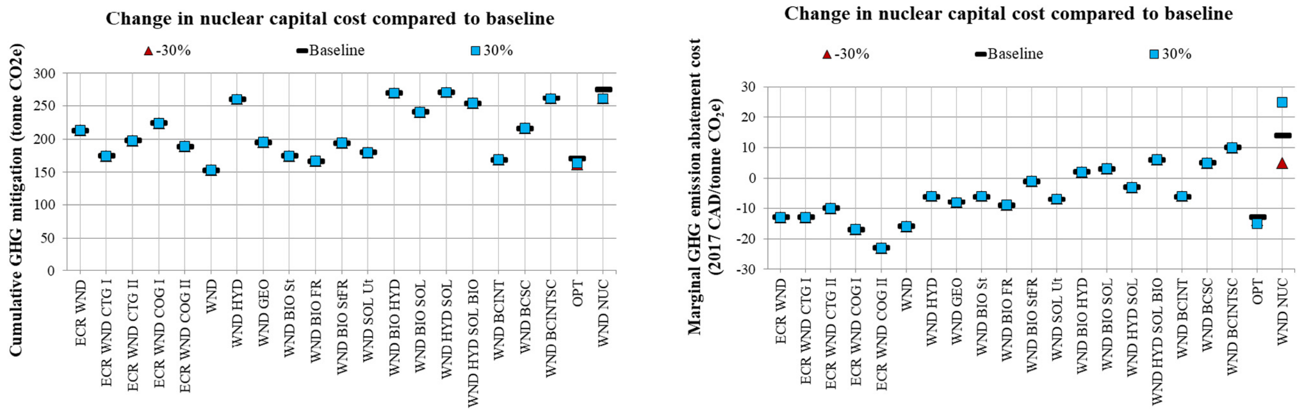

Fig. 13. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher nuclear power capital costs.

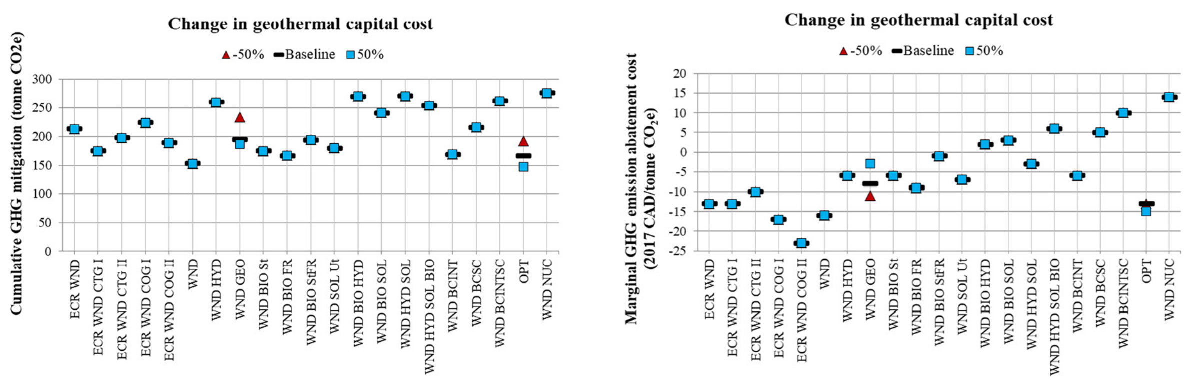

Fig. 14. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher geothermal-based power capital costs.

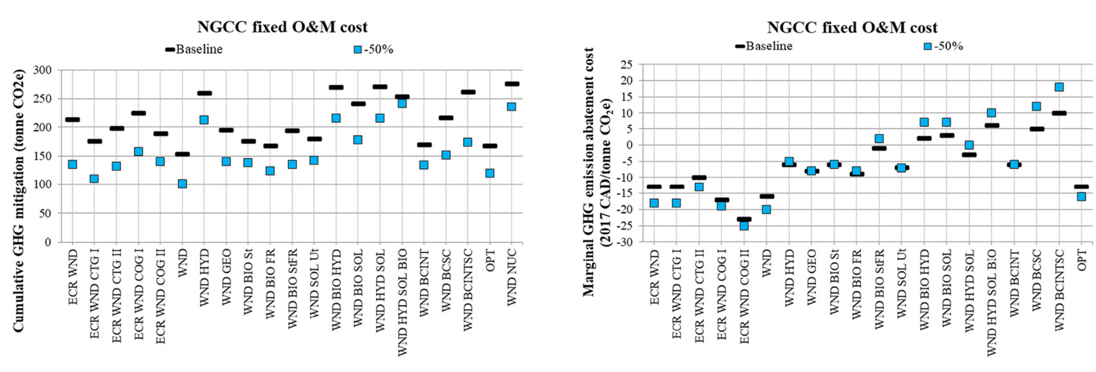

Fig. 15. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under lower and higher NGCC fixed operating and maintenance costs.

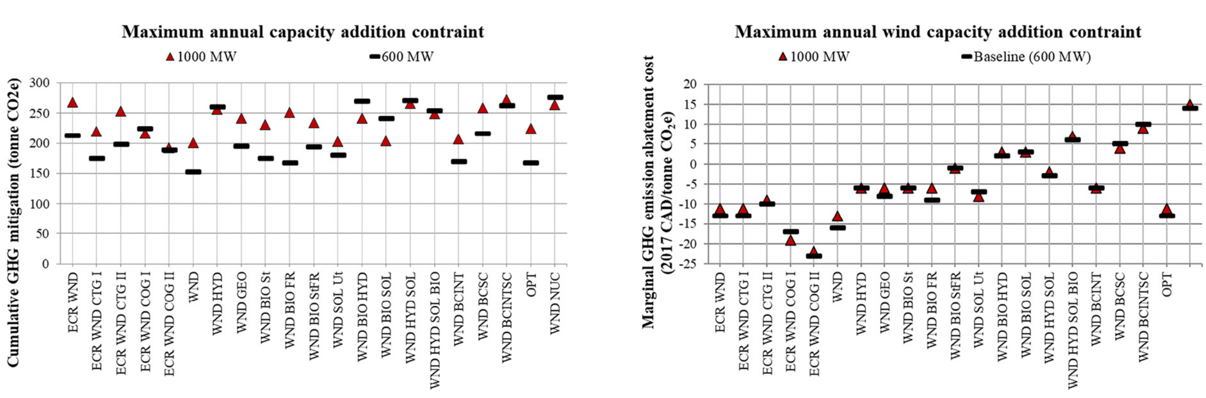

Fig. 16. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under higher annual wind addition limit.

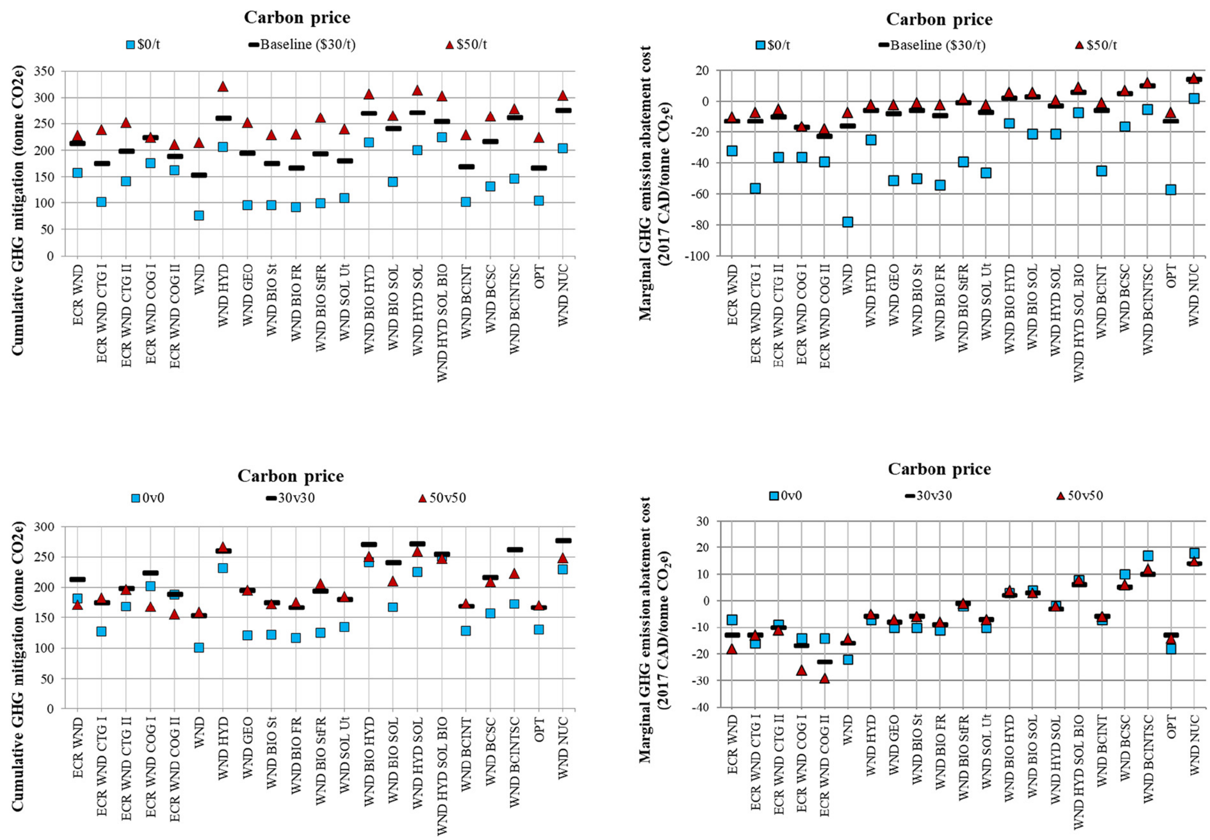

Fig. 17. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under different carbon pricing policies.

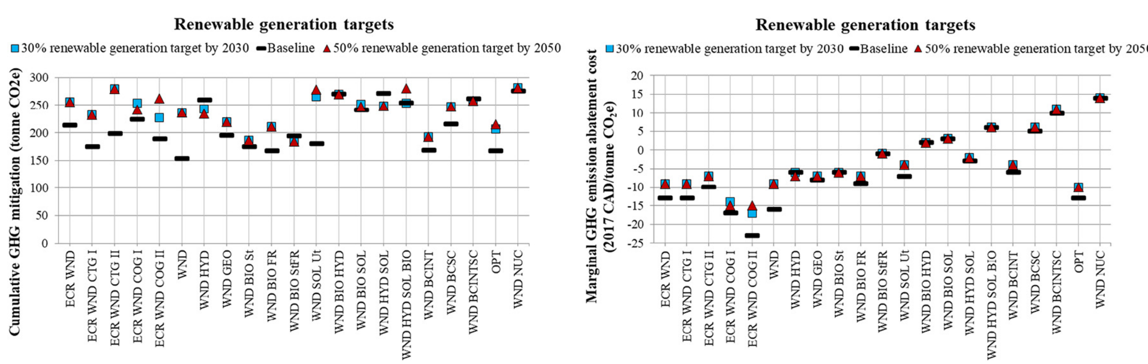

Fig. 18. Cumulative GHG mitigation (left) and marginal abatement cost (right) results under renewable generation targets.

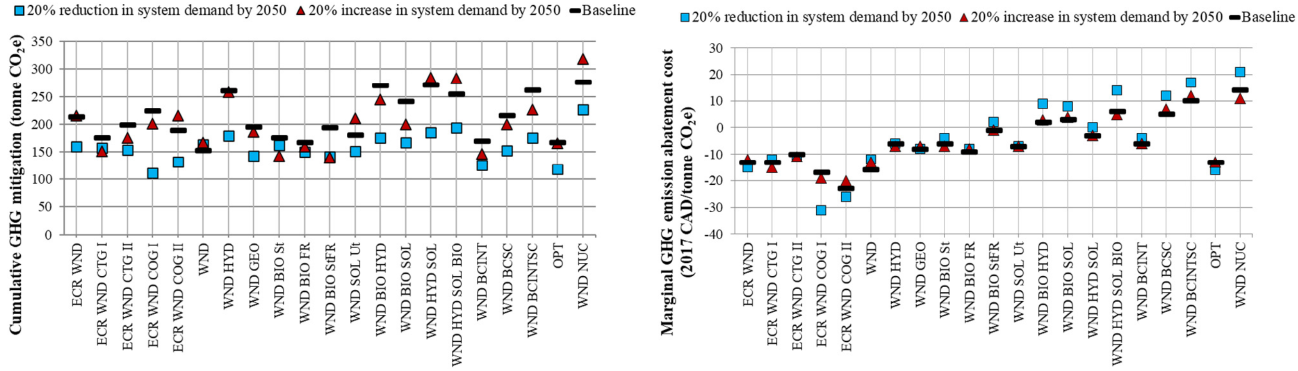

Fig. 19. Cumulative GHG mitigation (left) and marginal abatement cost (right) results for system demand changes.

Changes in the projected system demand resulted in expect changes to the cumulative GHG mitigation (Fig. 19). A reduction in 20% of system demand in 2050 produced a decrease in cumulative GHG mitigation by an average of 25%, due to less opportunity to transition the sector to higher renewable shares from the decreased capacity addition requirements. A 20% increase in system demand by 2050 resulted in an average of an 11% increase in GHG mitigation compared to the baseline levels. With more system demand, more new capacity is added, which is largely wind capacity, which increases the overall share of renewables in the system.

Limitations

The analysis presented in this work was structured around the concept of marginal system-wide costs. They do not reflect financial feasibility for individual technology choices or investment costs but rather a net cost impact across the entire system. Provincial transmission and distribution infrastructure changes, plant location, plant size and layout alternatives, energy storage, and fine time steps were not considered but would improve the analysis as pointed out by the literature (Abdulrahman & Wood, 2019; Deng & Lv, 2020; Luo, Sezer, Wood, Wu, & Zareipour, 2019). However, including these factors is not expected to change the conclusions of the paper. For instance, the provincial transmission and distribution system infrastructure requirements might vary across the scenarios depending on the mix of technologies, and add to system costs, especially in the case of higher capacity variable output generation. GE Energy Consulting (2016) conducted a study that included an assessment of reinforcing transborder interties to mitigate curtailments from wind power at up to 50% wind generation in Alberta, similar to the levels of wind power in the present study. Costs for the upgrades were quantified at $289 million (2016 CAD) for 10 GW of new transfer capacity and the investment was found to have a simple payback of 3 years considering avoided operating costs across Canada and the United States of America.

Least-cost optimization was used to determine some amounts of capacity expansion and generation within imposed constraints and in some cases, minimum levels of specific technology deployment. Optimization approaches can project results that diverge from eventuality since generation costs are not the only factors or influences that result in the actual trajectory of an electricity sector. Nonetheless, a large comparative scenario analysis offers applicable insights for cost-effective and technically feasible clean electricity generation pathways and provides valuable information to policymakers.

Conclusions

This paper studied energy transition pathways in a fossil-fuel-based electricity sector, an important transition that must take place globally to mitigate climate change impacts and ensure sustainable energy development. A new electricity supply and demand systems model was developed using the Long-range Energy Alternatives Planning system, validated, and used to carry out a scenario analysis for Alberta, Canada. The business-as-usual scenario was validated to be a close representation of the jurisdictional electricity operator's long-term outlook. Twenty-one baseline alternative electricity mix scenarios were developed and evaluated to assess a future with high amounts of renewables. A marginal abatement cost curve was developed to compare scenario GHG abatement potentials and marginal costs. The robustness of the results was improved though sensitivity analysis by changing key uncertain future conditions considering the natural gas price, key technology costs, carbon price, renewable generation targets, wind capacity addition constraints, and system electricity demands; 382 scenarios in total. This represents a novel contribution to the literature through comparison of an extensive range of technology mixes within a single study framework. The modelling framework can be applied to other jurisdictions transitioning away from fossil-fuel electricity systems to renewables.

In general, it was found that many renewable-based scenarios produced net system cost savings with significant GHG abatement giving negative marginal GHG abatement costs compared to the business-as-usual scenario. This indicates that there are many future renewable technology mixes that would both lower system costs and be more environmentally beneficial compared to a mostly natural gas-based business-as-usual scenario. The technology mix which a negative marginal abatement cost and the largest abatement potential was a combination of increased wind, hydro, and solar power which resulted in over a 90% reduction from 2005 emission levels. This was found to be possible considering system reserve margin requirements, variable output and low firm capacity rating of wind and solar, renewable resource availability, and low natural gas costs. Similar results were obtained for both a fully optimized scenario, where the technology mix was chosen based on the lowest system net present value, as well as for scenarios with exogenously specified high growth of renewable technology combinations. Wind and early coal retirement and conversion to natural gas were shown to produce negative marginal abatement costs with 14–25% GHG emission abatement. The results can inform policymakers of what technology-mixes would be most cost effective to transition to achieve a desired GHG reduction or renewable portfolio targets.

The jurisdiction of interest in this study was Alberta, a carbon intensive Canadian province. Alberta has a renewable energy generation target of 30% by 2030. The analysis shows that 35% renewable generation is possible at a negative abatement cost with an addition of about 3.5 GW of hydro and 4.5 GW of wind, given that the hydro sites can be developed at the modelled costs. Even with 20% higher hydro capital costs, the sensitivity analysis shows that the marginal abatement cost by 2050 remains negative. Canada is beginning work towards achieving net zero emissions by 2050, as well as fulfilling their commitments to meet and exceed their 2030 mitigation target. A combination of Alberta wind and hydro expansion can provide negative marginal abatement costs in the 2030 and 2050 time frames as well as contribute about 31 million tonnes, or 10%, to Canada's 2030 emission reduction target. This shows both provincial and federal benefits exist in the short and long term in the form of both economic benefit in Alberta and progress towards climate goals for Canada.

Declaration of competing interest

None.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.esd.2020.10.011.

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