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The role of U.S.-Canada electricity trade in North American decarbonization pathways

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ABSTRACT

We investigate the role of U.S.-Canada electricity interconnections in supporting decarbonization efforts toward addressing both countries' emission reduction goals. Using the OSeMOSYS energy system model, we calculate the generation mix and required transmission expansion between Canada and the U.S. under six climate policy and transmission cost scenarios. Overall, current emission prices will not provide enough incentive to meet stated emission reduction goals. Increases in emission penalties lead to increased transmission capacity. In all cases, the system requires significant dispatchable, low-carbon electricity to meet emission reduction goals and the flexibility of hydro resources provides significant system value. In addition to hydro and low-carbon dispatchable generation, the system requires significant investments in wind and solar in all scenarios.

1. Introduction

Both the U.S. and Canada have announced climate plans with ambitious emission reduction goals. The U.S. has set new targets, which include a 50–52% reduction from 2005 levels in economy-wide net greenhouse gas (GHG) pollution by 2030, and net-zero emission economy-wide by no later than 2050 [1]. This goal is to be accomplished by investing in infrastructure and innovation and fueling an economic recovery. In Canada, the plan titled "A Healthy Environment and a Healthy Economy" will increase the country's carbon tax by C $10/metric ton (mt) every year until 2030 starting in 2022 [2]. The Canadian plan includes C$15 billion in new investments in grid modernization, green and inclusive community buildings, home energy efficiency upgrade grants, zero-emission vehicles program incentives, and more. Both plans place significant focus on both electrification and the decarbonizing of generation in the electric grid.

The electricity systems of Canada and the U.S. are closely interconnected. In 2019, Canada exported 52 million megawatt hours (MWh) of electricity (8% of its electricity generation [3]) to the U.S. and imported 14 million MWh [4]. 67% of Canadian electricity comes from renewable sources, mainly hydro with smaller amounts from wind, solar, biomass, geothermal, and tidal [5]. With nuclear included, Canada's electricity in 2018 was 82% sourced from non-GHG emitting sources [6]. Meanwhile, the U.S. obtained only 20% of its electricity from renewable sources in 2020 and non-GHG emitting sources accounted for only 38% of U.S. generation in 2019 [7,8].

Expanding electricity trade between Canada and the U.S. could help both countries decarbonize their electricity systems more cost-effectively and enable both countries to leverage the most favorable low- and zero-carbon resources. For example, Canada has significant installed hydroelectric generation capacity and potential and is the third largest producer of hydropower in the world [9], while the U.S. has abundant solar resources [10]. Similarly, electricity demand in most of Canada tends to be higher in the winter [11] while load profiles in most of the U.S. peak in the summer [12]. Hence, an expansion of electricity trade between Canada and the U.S. — enabled by cross-border transmission investments — could allow the North American electricity system to be decarbonized at a lower overall system cost.

In this paper we investigate the role of U.S.-Canada electricity generation and trade in supporting decarbonization of the integrated system. We implement an Open Source Energy Modeling System (OSeMOSYS) model to represent the electricity systems of Canada and the U.S., regionalized into 18 geographic areas. The OSeMOSYS framework is a least-cost energy system optimization model that makes capacity expansion planning decisions to satisfy electricity demand at the lowest possible cost. To investigate the role of U.S.-Canada electricity trade in North American decarbonization pathways, we analyze scenarios defined by the stringency of climate policy and the cost of

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building new transmission between Canada and the U.S. This allows us to quantify the value of new cross-border transmission capacity, assess how its value depends on climate policy, and evaluate how electricity trade interacts with the capacity and generation mixes in both countries.

This study contributes to the growing literature on electricity sector decarbonization in Canada and the U.S., and in North America as a whole. Compared to the majority of previous studies that focused on individual North American regions (e.g., Eastern Canada and the Northeastern U.S.), our model represents both countries in their entirety within its unified scope. Our model source code and input data are available as open source supplementary material.[1]

We first provide background information on electricity trade between Canada and the U.S. including its potential to reduce GHG emission in Section 2. In Section 3, we review the relevant literature. We describe the OSeMOSYS framework employed for this study in Section 4, then provide details about how we apply the model to Canada and the U.S. The scenarios explored in this paper are described in Section 5. Section 6 presents results. Finally, we conclude in Section 7 by identifying future research directions that could be addressed using the publicly available open source OSeMOSYS model of Canada and the U.S. developed for this paper.

2. Background on U.S.-Canada electricity trade

Electricity trade between Canada and the U.S. plays an important role in the North American electricity system with significant energy flows across the border in both directions. Large quantities of Canadian hydroelectricity from Manitoba, Ontario, Quebec, and Newfoundland are exported to electricity markets in the U.S. Northeast and Upper Midwest. New England and New York account for more than half of all electricity imports into the U.S., and most of these imports are sourced from hydro generation in Eastern Canada [13]. In western North America, electricity trade is more balanced because both the U.S. Pacific Northwest and the Canadian province of British Columbia possess abundant hydro resources. In Canada there is significant potential for additional hydro generation capacity to be developed, and several large hydroelectric projects are currently under construction [14].

Other renewable sources such as wind and solar generation are increasingly being installed in both Canada and the U.S. Of the planned 39.7 gigawatts (GW) of new electricity generating capacity expected to commence commercial operation in the U.S. in 2021, solar will account for the largest share of new capacity at 39% (far surpassing 2020's nearly 12 GW increase), followed by wind at 31% [15]. Canada is poised to install as much as 2 GW of solar and wind capacity in 2021, which would represent a significant increase over 2020's total completed projects of 236 MW [16]. As these intermittent forms of renewable generation continue to grow, so do the potential gains from inter-regional electricity trade, including cross-border trade between Canada and the U.S. For example, the well-known "duck curve" phenomenon in California, where increasing penetration of solar generation has drastically reduced net loads in the middle of the day, suggests that U.S. regions with substantial solar generation could soon have excess electricity supply at certain times [17]. Exporting this excess electricity to Canada, which has inferior solar resources, would potentially balance the system during times of excess. Canadian hydroelectricity could be dispatched and exported to the U.S. in order to provide additional power during times of the day and seasons of the year when domestic wind and solar resources are unable to satisfy demand. Expanded transmission capacity can potentially allow for higher renewable generation and lower the overall system cost to meet GHG targets.

The U.S. and Canadian electric grids are already highly integrated and have a total capacity of approximately 18 GW [17]. Canada's Electric Reliability Framework highlights the 34 currently active transmission lines that connect to the U.S [18]. Increasing cross-border electricity flows would require additional transmission lines since the current lines are operating near their maximum capacities [5]. Among the six recent transmission line projects, the Soule River Hydroelectric Project that began to operate in 2017 offers an additional 0.077 GW of transmission capacity, while the Great Northern Transmission Line has been in service since 2020 and brings another 0.75 GW [3,13,19]. Meanwhile, there are three transmission lines still under construction—Champlain Hudson Power Express, Lake Erie Connector, and New England Clean Power Link—that will contribute 3 GW of additional transmission capacity in the future [20–22]. It is not clear if these existing projects will be adequate to realize the full renewable potential in both countries.

Meanwhile, the expansion of GHG emission pricing, or emission trading systems (ETSs), could accelerate the transition from carbon-intensive to low- and zero-carbon electricity sources [7]. ETSs have the ability to increase clean energy conversion in the power sector [23] and potentially incentivize more cross-border energy trade. As one example, electricity exports from Quebec to the U.S. have been shown to reduce GHGs, and transmission expansion has the potential to reduce GHGs even further. In one study, imports into Quebec were responsible for 7.7 Megatonnes (Mt) of GHGs from 2006 to 2008. Over the same period, Quebec's hydropower exports displaced 28.3 Mt of GHG emission [20], for a net of 20.6 Mt of avoided emission. How such ETS schemes and expanded transmission capacity interact remains to be fully studied, but it is clear that transmission capacity expansion can increase the impact of ETS schemes.

3. Literature review

We first review the energy system modelling tools that researchers use to study decarbonization pathways. We then review the existing literature on decarbonizing the electricity system, focusing on studies that evaluate specific geographic subsets of Canada and/or the U.S. Finally, we provide an overview of the most directly relevant studies that investigate larger spatial scopes and include representations of U.S.-Canada electricity trade.

3.1. Energy system optimization models

A wide range of energy modelling frameworks have been developed to evaluate and analyze the impact of environmental and climate change policies on the energy system. These frameworks assist policy makers and energy planners in making cost-effective infrastructure development decisions to satisfy energy demands and achieve environmental goals.

Herbst et al. [24] specifically discuss and compare top-down and bottom-up approaches to modelling frameworks. While top-down models describe the whole economy, bottom-up models focus on representing energy systems with rich technological detail [24–27]. Top-down models are driven by macroeconomic theory and do not evaluate the specifics of technological transitions. These econometric based models calculate how all sectors of the economy will react and equilibrate based on policy intervention. Bottom-up energy models do not include a complete representation of the economy but rather are engineering-focused to analyze how changes in policies, demand forecasts, and other factors will affect technology investments and operations over time.

To assess electricity interconnections, various electric infrastructure components must be represented in detail. Furthermore, the model needs to capture the unique properties of renewable resources, such as the intermittent outputs of solar and wind technologies. Therefore, bottom-up modelling approaches are applied to investigate the role of electricity trade in supporting decarbonization efforts. There are several widely known bottom-up models suitable for this type of analysis.

TIMES is a well respected general purpose model generator

[1] https://github.com/DeltaE/Canada-U.S.-ElecTrade

developed by the International Energy Agency [28]. TIMES allows for user-defined spatial and temporal resolutions for a specific energy-environment system. While the TIMES source code is available for free (under certain conditions), the model is written in the commercial software GAMS. This requires users to purchase the software.

MESSAGE is a medium-to long-term energy planning and energy policy analysis framework [29] developed by the International Institute for Applied Systems Analysis and currently has a number of variants designed for specific research applications. The selection of spatial and temporal resolution in MESSAGE is limited to predefined options built into the framework. This includes spatial resolution as fine as country level to as coarse as continents. Furthermore, while the model can extend out to 2100, users cannot incorporate time steps finer than five years.

The Open-Source Energy Modelling System (OSeMOSYS) framework was originally developed at KTH Royal Institute of Technology [30–32]. Much like TIMES, the framework allows for full user flexibility in choosing temporal and spatial resolution. Furthermore, the user can create, build, and solve a model using an entirely open-source workflow.

In summary, although there are a number of different modelling frameworks available to address research questions related to electricity transmission, trade, and capacity expansion planning, the OSeMOSYS framework is freely available, well respected, and well suited to addressing our research questions.

3.2. Studies of Canada and the U.S

There have been a number of studies on decarbonization pathways at the national or local scale for the U.S. and Canada where the focus has been on a sub-region of the U.S.-Canada system. We review these first before highlighting the limited work modelling the full U.S.-Canada system.

A few studies have focused on either Canada or the U.S. without considering cross-border trade between the two countries. Bataille et al. [33] study six decarbonization pathways under three main themes in Canada. In this study, the CIMS model is used to forecast demand and the GEEM model to attain GDP, employment, economic structures, and trade for the decarbonization paths in Canada. The results show that decarbonized electrification, improved energy productivity, reduced, capped, and utilized non-energy emission, movement to zero emission transport fuels, and decarbonized industrial processes are the main decarbonization strategies. Gupta et al. [34] use an integrated approach to evaluate the GHG emission, water footprints, and marginal abatement costs of electricity generation decarbonization pathways for Canada's electricity sector. Through a fully decarbonized scenario, water consumption savings and negative marginal GHG abatement costs are resolved. Vaillancourt et al. [35] evaluate deep decarbonization pathways to 2050 for Canada using the North American TIMES Energy Model (NATEM). They find that three fundamental transformations need to take place at the same time to meet economy-wide GHG emission reduction goals, including electrification of end-use sectors, decarbonization of electricity generation, and efficiency improvements. Jayadev et al. [36] implement a customized and expanded version of the OSeMOSYS model to obtain policy-relevant insights into future pathways for the U.S. electricity sector, including electricity generation and transmission between the states. The authors' conclude that storage investments play a more prominent role than transmission investment and natural gas capacity grows for reliability, but that utilization rates of natural gas generation drop. Brozynski and Leibowicz [37] modify the standard OSeMOSYS framework to study optimal energy system transformation pathways for achieving decarbonization goals at the urban scale, with Austin, Texas as a case study. Optimal decarbonization required the reduction of power sector emission, electrification of transportation, solar investment, wind investment to replace natural gas, and battery storage investment. Brown and Li [38] apply a fully integrated engineering-economic model of the U.S. energy system to explore the ability of the U.S. electricity sector to operate within a budget of 44 gigatons of CO2 between 2016 and 2040. Their results suggest that carbon taxes coupled with strong energy efficiency policies could meet the deep decarbonization goals. All of these papers focus on the decarbonization of just Canada or the U.S. and none include the entire U.S.-Canada system.

There is a large body of work that focuses on trade between eastern Canada and the U.S. northeast. One study focuses on the interactions between thermal generators in New York and hydro generators in Quebec [39]. Villemeur et al. find that hydropower plants' flexibility allows them to generate during peak hours and store water during lower-demand periods, reducing peak energy costs. Interestingly, they find that higher electricity trade can lead to an increase in electricity consumption, offsetting some of the environmental benefits from the use of clean electricity generation.

Similarly, Dimanchev et al. [40] use detailed hydro reservoir information from Quebec to evaluate trade with New England in the U.S. using the capacity expansion model GenX. They find that lithium ion battery storage is much less efficient when compared with storage of water behind dams in Quebec but do not evaluate expansion of trade between the regions. Yuan et al. [41] evaluate the potential for electricity trade between the Northeast U.S. and Canada (Quebec) through an "integrated top-down, bottom-up modelling" framework (USREP-ElecMod). The main focus of their study is the expansion of transmission in the Northeast region of Canada and the U.S. to meet CO2 emission caps. The authors consider a scenario with a 50% expansion of transmission capacity in the Northeast region, and quantify the cost savings as between 30 and 49 cents per kWh depending on location. Notably, the study assumes sufficient hydropower in Canada and excludes transmission capacity expansion costs. In another study, Rodriguez-Sarasty et al. [42] focus on the same region (Northeast U.S. and Canada) and employ a capacity expansion and dispatch model to investigate cross-border electricity trade, optimal transmission capacity expansion, and pooled capacity for peak load requirements. They find that deep decarbonization relies on the ability of hydropower to balance time-varying wind generation. These studies evaluate eastern Canada and the northeastern U.S. and do not include the entirety of the U.S. and Canada.

Only two studies have been identified that include the entirety of the U.S. and Canada. The National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDS) model is used to evaluate additions of wind generation in both countries and the retirement of coal and nuclear power plants [43]. Investments in transmission capacity are calculated based on the constant net energy exchange. The authors evaluate a number of scenarios based on either existing policies or on a carbon cap that reduces emission by 92% by 2050 in both countries. Their base case shows expansion of cross-border transmission capacity to 37 GW in 2050 whereas a carbon cap increases this to 41 GW. In addition, the North American Renewable Integration Study (NARIS) which began in 2016 and entailed many studies for a continental low-carbon grid, studied some of the scenarios that are included in our study. The following items were learnt from NARIS' studies [44]:

4. Multiple pathways to 80% power-sector carbon reduction by 2050 are resolved with a steep cost reduction of wind and solar technologies.
5. The balance of supply and demand can be accomplished in Canada and the U.S. by 2050 through future low-carbon systems.
6. Regional and international cooperation can provide significant net system advantages through 2050 with an increase of electricity trade.
7. Operational flexibility results from transmission, electricity storage and flexible electricity generation.

We build on this work but create different scenarios to calculate the electricity transmission and generation in Canada and the U.S. In this path, we include governmental policies and plans for emission reduction goals and consider transmission cost reduction as a testing factor.

In summary, although U.S.-Canada electricity trade has been analyzed in the literature, most studies use coarse spatial resolutions or focus only on specific geographical portions of the two countries. Studies that do cover the entirety of the U.S. and Canada are often spatially aggregated so that details of the trade between regions are not studied. We address these gaps by adding spatial regionalization of both countries based on North American Electric Reliability Corporation (NERC) data. We also use more detailed temporal resolution and investigate variation in transmission investment costs. Furthermore, we use the open source OSeMOSYS model and make our model and data available for further analysis.

4. Methods

We first describe OSeMOSYS, our selected modelling framework as introduced in the model overview earlier, including our adjustment to the reserve margin constraint. We then summarize our system representation and our spatial and temporal structure. Finally, we document our input data for technologies, commodities, and demands.

4.1. OSeMOSYS

The Open Source Energy Modelling System (OSeMOSYS) is a framework designed to support long-run energy planning [30–32]. OSeMOSYS is a deterministic, linear, least-cost optimization model that can cover all, or any subset of, energy sectors. Common examples of sectors that researchers choose to represent in OSeMOSYS include electricity, heat, and transport [45]. The model's variables are continuous, allowing fractional amounts of capacity to be built and energy to be generated, with capacity investments decided on yearly intervals. These assumptions are appropriate for our research question as we are analyzing long-term system-level capacity requirements.

The OSeMOSYS framework as applied in this paper allows for easy model modifications, includes tools for data pre-processing, and has an active online community. OSeMOSYS is written in GNU MathProg, a high-level mathematical programming language. This language allows modellers to easily read constraint equations, thus reducing the learning curve for new users of the platform. Furthermore, OSeMOSYS works with both open-source solvers and commercial solvers including CPLEX which was utilized in this study. User-created tools have been developed to aid in handling data for OSeMOSYS models. One such tool applied for this project is the python package otoole [46]. Furthermore, OSeMOSYS is an open-source framework hosted on GitHub [47] and has a n active community support forum Google group [48]. Niet et al. [32] provide an overview of recent developments with OSeMOSYS and show how it is actively being maintained and updated over time. We refer readers to this paper for additional details and information on OSeMOSYS.

4.1.1. Reserve margin

NERC defines the reserve margin as the percent difference between available capacity and peak demand to ensure adequate capacity is available to meet unexpected increases in each region's demand [49]. In the original OSeMOSYS model, the reserve margin is applied to the whole model as one global value and cannot be applied regionally. We revise the reserve margin constraint in OSeMOSYS to allow the constraint to be applied to each region. This aligns with the NERC regional definition of reserve margin. Specifically, we alter the formulation to index over the regionally defined fuels rather than sum them to a global reserve margin. This allows us to apply reserve margin values to both different fuels within the same region and to apply region specific reserve margins. This also allows trade technologies to be considered in the reserve margin following NERC guidelines. The specific code changes are shown in the appendix.

4.2. System representation

This section provides an overview of the general energy system structure that is replicated for each model region, then outlines our choice of temporal and spatial resolution.

4.2.1. Energy system structure

Fig. 1 shows the energy system structure implemented in the model. The technologies implemented can be separated into fuel supply, power generation technologies, transmission and distribution infrastructure, and final regional demand. The fuel supply represents the raw resources that power generation technologies require to run. These fuels can either be physical commodities (such as coal) or renewable resources. Multiple power generation technologies can use the same raw resource to generate electricity, such as natural gas used in both combined and open cycle generation facilities. The transmission and distribution technologies connect supply and demand between regions.

The structure of Fig. 1 is repeated for each region in the model. Interconnections are incorporated via the transmission and distribution technologies. Electricity flows from one region through the trade export technology into the adjacent region's trade import technology.

4.2.2. Temporal resolution

Our project investigates the role of electricity trade in a system undergoing decarbonization over many years. A decarbonized future electricity system will need to incorporate growing shares of variable renewable energy generation sources, such as wind and solar. Capturing the time-varying generation profiles of these sources is critical to accurately evaluate energy planning questions.

Numerous studies investigate the impact of temporal resolution on model results. Pfenninger et al. [50] discuss the tradeoffs between temporal resolution and computational feasibility. Moreover, studies such as those by Haydt et al. [51] and Bistline et al. [52] investigate the impact of temporal resolution on models that incorporate large shares of intermittent renewables. Haydt et al. show that models that do not accurately capture the intermittent nature of renewable sources overestimate their generation capacity and underestimate system CO2 emission. However, Bistline et al. note that using representative dispatch days for long-range model horizons is generally an acceptable approach. Finally, Connolly et al. [53] perform a review of modelling tools and frameworks to investigate renewable energy integration. They note that no one tool is perfect for analyzing decarbonization. Instead, the burden is on the user to review the available frameworks and select the best framework to answer their specific research question.

Capturing the intermittency of a renewable energy source over a 24-h cycle is a requirement for exploring the impacts of variable renewable generation. Therefore, we implement a time slice structure where each year is represented by four representative 24-h days. Each day represents an average day in each of the four seasons. This is the same structure that Jayadev et al. [36] use in their paper on electricity decarbonization pathways for the United States.

4.2.3. Spatial resolution

Factors such as natural resource quality, demand profiles, and generation capacity mixes can bias model results if spatial resolution is not considered. Without taking this into account, relationships between variable resource availability and demand profiles will not be captured [54]. To reflect spatial variations, we divide the U.S. and Canada into numerous subnational regions.

The geographical extent of each Canadian region is primarily driven by NERC's regional organizations. NERC splits Canada and the continental U.S. into six organizations of similar size and complexity [55]. Splitting the NERC organizations at the international border creates three Canadian regions, the West, Midwest, and East regions. We subdivide the East region into three smaller regions: the Ontario region, the Quebec region, and the Atlantic region to capture the impact of the large

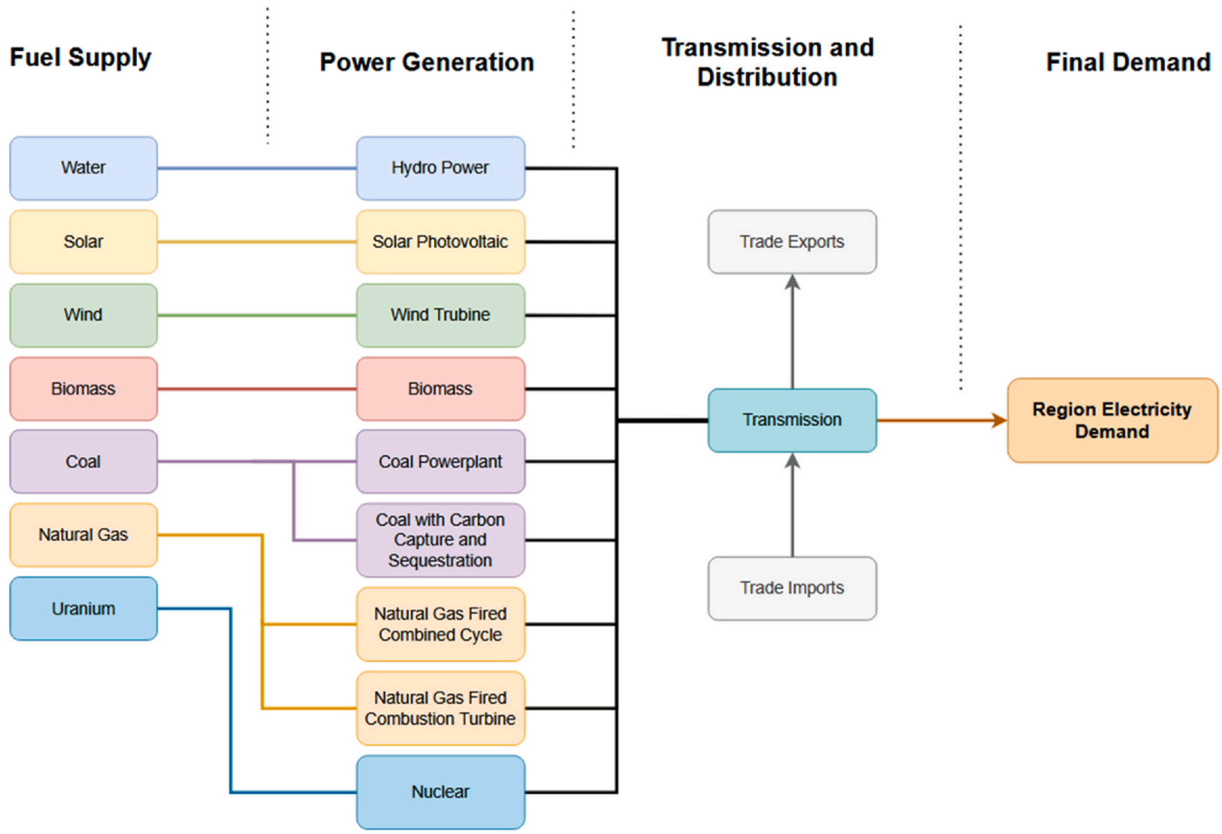


Fig. 1. Reference energy system of the U.S.-Canada OSeMOSYS model.

demand and generation assets in Ontario and Quebec. This additional split evens out regional demands and creates roughly evenly sized regions across Canada. Moreover, this spatial aggregation aligns with previous studies of the Northwest, such as that done by Ref. [42]. The five Canadian regions are summarized in Table 1. The three northern territories of Yukon, Northwest Territories, and Nunavut have been omitted from this study as these territories have little transmission interconnection with the rest of Canada and account for only a small percentage of Canadian generation and demand [56].

We follow the same regionalization approach as Jayadev et al. [36] for the United States. They divide the continental U.S. into the 13 regions outlined in Table 2. Their spatial representation primarily follows the EIA reporting regions. However, they made several modifications to these regions so that states with similar generation capacity mixes and demand profiles are grouped together, and states that differ significantly in these respects are represented in separate regions. For example, they separate Washington and Oregon from the Mountain North region because Washington and Oregon feature significant hydro generation and a milder climate.

Table 1
Canadian region definitions.

Model Region	Abbreviation	Provinces Included
West	WS	British Columbia, Alberta
Midwest	MW	Saskatchewan, Manitoba
Ontario	OT	Ontario
Quebec	QC	Quebec
Atlantic	AT	New Brunswick, Newfoundland, Nova Scotia, Prince Edward Island

Table 2
United States region definitions.

Model Region	Abbreviation	States Included
North West	NW	Washington, Oregon
California	CA	California
Mountain North	MN	Montana, Idaho, Wyoming, Nevada, Utah, Colorado
Southwest	SW	Arizona, New Mexico
Central	CE	North Dakota, South Dakota, Nebraska, Kansas, Oklahoma
Texas	TX	Texas
Midwest	MW	Minnesota, Wisconsin, Iowa, Illinois, Indiana, Michigan, Missouri
Arkansas-Louisiana	AL	Arkansas, Louisiana
Mid-Atlantic	MA	Ohio, Pennsylvania, West Virginia, Kentucky, Virginia, New Jersey, Delaware, Maryland, District of Columbia
Southeast	SE	Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia
Florida	FL	Florida
New York	NY	New York
New England	NE	Vermont, New Hampshire, Maine, Massachusetts, Connecticut, Rhode Island

4.3. Technologies and commodities

We include nine electricity generation technologies and six raw fuel types in our model. The generation technologies can broadly be categorized as thermal, variable renewable, and non-variable renewable generation. Trade is modelled as a separate technology and its functionality is separately discussed below.

Thermal generation facilities include coal, gas, and nuclear power. Coal generation technologies include both coal-fired power plants and coal-fired power plants with carbon capture and sequestration (CCS).

Coal has a high CO2 emission rate and recent efforts have begun to phase out coal power from the generation mix [57]. Introducing CCS functionality allows for a less environmentally harmful coal-fueled technology to be incorporated, but at increased capital cost. Two gas-fired power plant types are modelled, a combustion turbine (or a simple cycle) and a combined cycle. Existing gas power plants are primarily categorized into these two categories with each having unique efficiencies and emission ratings. Finally, nuclear power plants have been included as a thermal generation technology. However, they differ from coal and gas power plants because they do not emit CO2.

Renewable energy generation sources can either have variable or non-variable production. Variable renewable energy generation facilities rely on daily weather conditions to produce electricity. Included in this category are photovoltaic solar and onshore wind power. Non-variable renewable energy generation facilities can produce electricity independent of daily weather conditions. Instead, their production is linked to seasonal weather patterns and facility restrictions, such as planned maintenance. Dammed hydropower and biomass are included in this category. We do not model hydro reservoir levels or dynamically track water flow rates throughout the model horizon. Instead, we allow the dam to choose how much to generate over each time slice, while not exceeding a yearly maximum generation limit based on historical values. This introduces the assumption that minimum reservoir levels are always met and that hydrological cycles remain constant. These assumptions can introduce operational errors, with a complete list being summarized by NREL [58], however, they allow the problem to remain computationally tractable. For in-depth studies on hydropower utilization, including hydrological data and linking our model to a short-term power system model would be required, which is beyond the scope of this paper.

National and international electricity transmission options are introduced through trade technologies. Each trade technology links one adjacent region to another. Intra-regional transmission and distribution infrastructure is not represented, and electricity is assumed to freely flow within each region without cost. For each time slice, trade on a link can only occur in one direction, thereby eliminating the possibility of two regions exporting electricity to each other at the same time.

All technologies are modelled to have efficiencies and emission factors. The efficiencies for generation technologies are extracted from the EIA Annual Energy Outlook [59], while transmission technologies have a globally applied 95% efficiency rating [60]. The emission activity ratio, which represents mass of CO2 emitted per unit of activity, is retrieved from the Intergovernmental Panel on Climate Change performance parameters report [61]. A constant emission penalty used in our study for both countries is the highest penalty from the Canadian provinces in 2019 [62], namely $30CAD ($24USD).

Table 3 summarizes the data sources that define the technological characteristics of the model for each country. Additional details of the data sources, and reasoning behind data choices, are available on GitHub (see footnote 1).

4.3.1. Generation profiles for variable renewables

The generation profile represents the potential of a variable renewable technology to provide generation in each time slice. These profiles account for daily, seasonal, and yearly weather variations that affect production, and also for maintenance and other planned downtimes.

Table 3
Documentation of technology data sources.

Parameter	Canadian Data	United States Data
Efficiency	[59,60]	[59,60]
CO2 Emission Factor	[61]	[61]
Operational Life	[63]	[64]
Capacity Factor	[64–67]	[64,68]
Residual Capacity	[66,69]	[70]
Capital Cost	[64]	[64,71]
Fixed Cost	[64]	[64]
Variable Cost	[64]	[64]

Canadian provincial capacity factors for wind and solar resources are collected using Renewables. ninja [65]. This software provides hourly power output from wind and solar farms located anywhere in the world. Hydropower production limits for Canada are calculated using historical annual provincial generation and capacity values [66,67]. Coal, natural gas, nuclear, and biomass capacity factors are extracted from the NREL Annual Technology Baseline report [64]. Regionalized capacity factor values are calculated through a weighted average based on provincial annual demand. The 2019 historical capacity factor values are used for all years in the model horizon. In the United States, most technologies' capacity factors can be obtained from Refs. [64,68], however the wind and solar capacity factors are estimated using the NREL System Advisor Model (SAM) software, following Jayadev et al. [36].

4.3.2. Residual capacity

The residual capacity is any capacity installed before the start of the model horizon which has remaining life and can be used to meet demand during the first years of the model horizon. Residual capacity data is separated into generation and transmission line residual capacities. Canadian generation capacity data is aggregated from both Statistics Canada and Canada Energy Regulator databases [66,69], while the U.S. generation capacity data is collected from the U.S. Energy Information Administration (EIA) [70]. Domestic and international Canadian transmission line capacities are collected from Statistics Canada [18,72], while the U.S. domestic transmission line capacities are collected from Jayadev et al. [36]. The locations of existing interconnections between Canadian and United States regions are collected from the Center for Strategic and International Studies [73].

4.3.3. Costs

Three costs are associated with all technologies in OSeMOSYS: capital costs, fixed operation and maintenance costs, and variable costs. All generation technology costs are collected from the NREL 2020 Annual Technology Baseline (ATB) [64]. NREL provides a representative value for each technology closely aligned with recently installed electricity generation plants. We use the representative value cost for each technology as it provides a reliable average baseline for all geographies. The U.S. capital costs provided by NREL ATB do not reflect regional cost variations; hence, we apply the average value of location-based adjustment factors provided by EIA [71] in each region as a regional cost multiplier. Furthermore, fuel costs are built into variable costs for generation facilities that use consumable fuels. These fuels include coal, natural gas, uranium, and biomass.

Transmission capital costs depend on several factors such as number of circuits, voltage ratings, and distance. In general, the transmission line load limit reduces as the distance increases. This is due to the increase in resistance and additional power losses. Using the St. Clair Curve [74], the assumption that only 500 kV double circuits are used [75,76], and the estimated distance between regions, the capital cost per power unit is calculated. Under these assumptions, the load-ability of a standard 500 kV transmission line 300 miles (482.8 km) long is not derated and is 900 MW [77–79]. We use this as the standard transmission line in the model and adjust the load-ability for longer links respectively. Due to the challenge in measuring lengths between load centres, international connections are assumed to stretch only 100 km. We further assume negligible distance-based variable operation and maintenance costs.

4.4. Demand

Table 4 summarizes the data sources used to define the electricity demand in each region. Full details of the data sources, and reasoning behind data choices, are available on GitHub (see footnote 1). We provide summary details of the annual demand in each region, the

Table 4
Documentation of demand data sources.

Parameter	Canadian Source	United States Source
Annual Demand	[80]	[81,82]
Demand Profile	[83–86]	[87–91]
Reserve Margin	[49]	[49]

calculation of demand profiles, and the applied reserve margin below.

4.4.1. Annual demand

Canadian provincial energy demands for 2005 to 2050 are documented by the Canada Energy Regulator [80]. EIA provides the U.S. electricity demand data [81,82]. As shown in Fig. 2, system-level electricity demand is forecasted to steadily increase over the model horizon with both countries following similar year-over-year trends. There is a slight dip in demand from 2019 to 2021 in both countries, likely due to the Covid-19 pandemic affecting electricity consumption habits, as discussed by the EIA [92].

4.4.2. Demand profiles

Hourly provincial load profiles for Canada are supplied by provincial electric utility companies and system operators, such as BC Hydro and the Alberta Electric System Operator [83–86]. Not all provincial utility companies freely provide hourly demand data. In these cases, we assume the profile of the neighbouring province with the most similar annual demand. United States load profiles can be found at [87–91]. An example of a demand profile for the Pacific Time Zone is available in the appendix.

4.4.3. Reserve margin

The reserve margin represents the additional installed capacity above the peak demand required to ensure stable system operation. NERC suggests reference reserve margin levels of 15% for thermal-dominated regions and 10% for hydro-dominated systems [49]. We apply this reference level reserve margin value to each individual region in the model. Next, a weighted average reserve margin for each region based on annual demand values is calculated.

Aggregating seasonal demand profiles into four representative days entails tradeoffs. Mainly, computational time is reduced at the expense of averaging data across hours in the year and losing some features of the true annual demand profile. This is particularly challenging when applying a reserve margin. As Bistline et al. [52] note, using representative days tends to average away real-world peak demands, underestimating the required capacity. To account for this issue, we implement an adjusted reserve margin value. The adjusted reserve margin value accounts for true demand peaks that have been averaged out during the time slicing process. It is a region-specific value that is calculated through adding the percent difference between the actual peak demand and time sliced peak demand to the reference level reserve margin.

5. Scenarios

We analyze several scenarios including a business-as-usual (BAU) case and five scenarios with varying emission limits and transmission costs. The scenarios we consider are summarized in Table 5. In the BAU case (ER0TC0), there are no emission limits and baseline transmission costs are used. Each scenario applies different climate policies and capital costs of transmission capacity. The moderate climate policy (ER50) follows the Pan-Canadian-Framework of reaching a 50% reduction in Canadian emission by 2030 compared with 2005 levels [93]. In our scenario, we add an emission limit of 50% by 2030 for both countries compared with the 2019 levels and then maintain this level through the end of the model timeframe. The aggressive climate policy scenarios (ER100) apply a net-zero electricity sector emission constraint by 2050 as pledged by many countries, although pledges by the U.S. and Canadian governments to date fall short of bringing CO2 emission to zero by 2050 [94].

For transmission costs there is evidence that enhancing the transmission planning process can impact overall capital costs. The Independent System Operators/Regional Transmission Organizations (ISOs/RTOs) note that transmission developers show great interest across Jurisdictional ISO/RTO regions, potentially offering 20–30% cost savings based on international experience [95]. In our transmission cost

Table 5
U.S-Canada scenarios.

Climate Policy \ Trade Policy	Current Transmission Capital Costs	30% Reduction in Transmission Capital Costs (C30)
No Emission Reductions	ER0TC0	ER0TC30
50% Emission Reductions by 2030	ER50TC0	ER50TC30
100% Emission Reductions by 2050	ER100TC0	ER100TC30

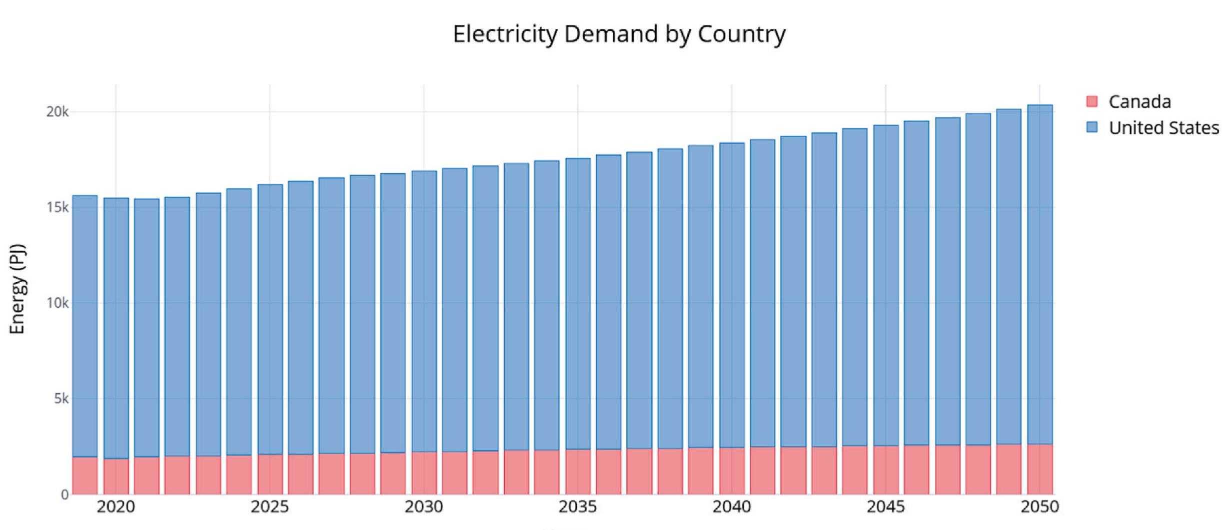


Fig. 2. Projected annual system electricity demand.

reduction scenarios, we use the high end of the estimated possible cost savings and incorporate a 30% reduction in the capital costs of transmission lines (TC30).

In addition, for the ER100TC30 scenario, to highlight the value of flexibility in hydro operation and address the large installed capacity of hydro in this scenario we test two options. The first does not limit hydro installed capacity while the second restricts hydro capacity to existing capacity and currently planned expansions. The limit is only applied to the ER100TC30 scenario as this is the only scenario where significant additional hydro capacity ends up being installed.

6. Results and discussion

We present results on the installed generation capacity, the generation mix, transmission investments and electricity trade, emission levels, and finally system cost.

6.1. Installed generation capacity

Fig. 3 shows the installed capacity through the model horizon for the BAU and the net-zero scenarios for Canada and the U.S. Notably, in the BAU scenario, gas is installed and provides the majority of generation capacity by 2050 in both countries. Gas plants provide the system with a low-cost (to install and run), dispatchable generation source. Moreover, the system-wide emission penalty is not high enough to discourage gas generation.

Comparing the BAU results in Fig. 3 to the net-zero emission results, significant increases are seen in wind, solar, and gas capacities in the U.S. and hydro capacities in Canada by 2050. This is expected since non-emitting generation facilities must be built. Counterintuitively, as emission limits become more stringent, system-level gas capacity continues to increase. This is attributed to the reserve margin requiring firm capacity since the gas generators can be installed but not run, they can exist as emergency backup in the net-zero scenario, though it is unlikely that they would be built if they cannot recoup the capital investment. Throughout the model horizon, the generation mix shifts towards variable renewables. However, wind and solar capacity have insignificant contributions to the reserve margin because of their intermittent nature and it is therefore cheaper to invest in gas facilities whose only purpose is to meet reserve margin capacity constraints. This is compared to building expensive hydro and/or nuclear to meet generation, emission, and reserve margin requirements with one technology. This highlights our earlier observation that gas is cheap and dispatchable, and thus an attractive option.

Achieving net-zero emission by 2050 will require generation from emission-free variable and non-variable energy sources and, as expected, the net-zero scenario relies heavily on significant wind and solar expansion. Hydropower, though expensive and geographically restricted, does get installed. There is likely not enough hydropower available in Canada and the U.S. to support this scale of growth [96,97] but restricting hydro power requires additional dispatchable emission-free and flexible energy generation solutions to achieve net-zero. Nuclear power meets these requirements; however, its high capital costs and political and social challenges make it difficult to deploy. Alternatively, the disadvantages of nuclear and hydropower provide a potential opportunity for large-scale storage systems.

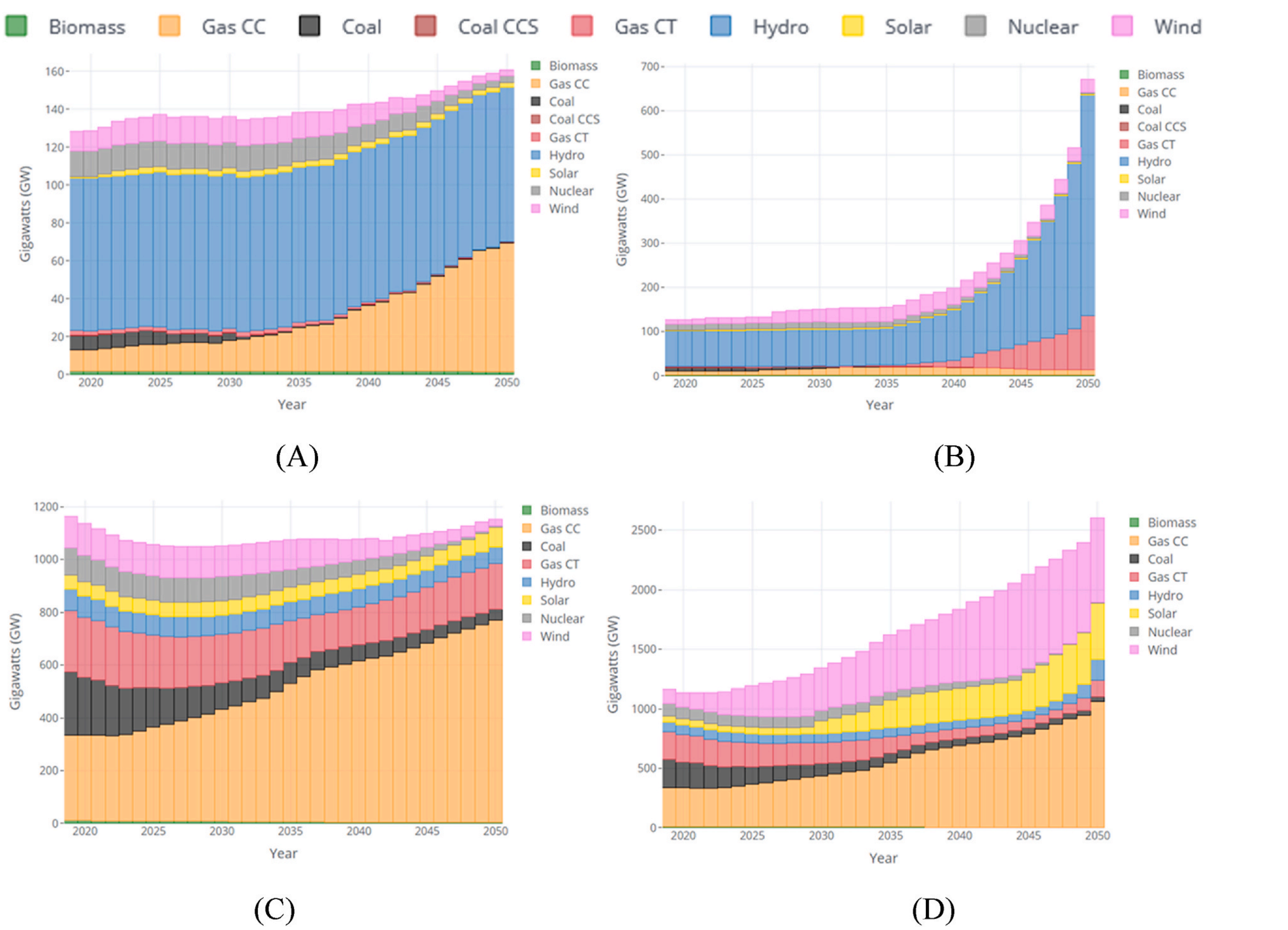
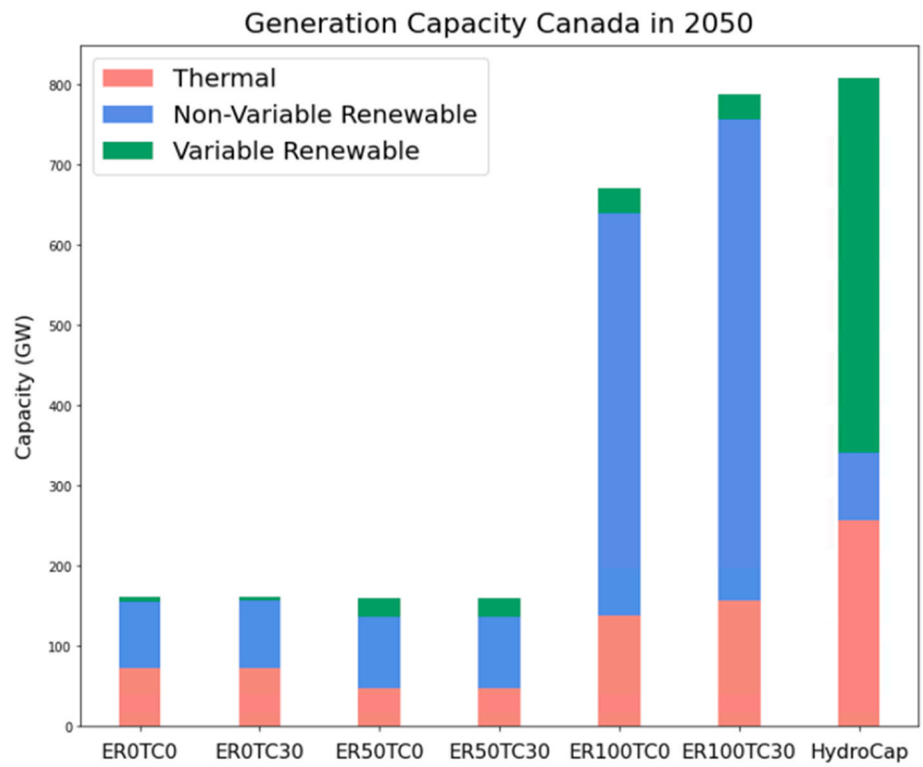


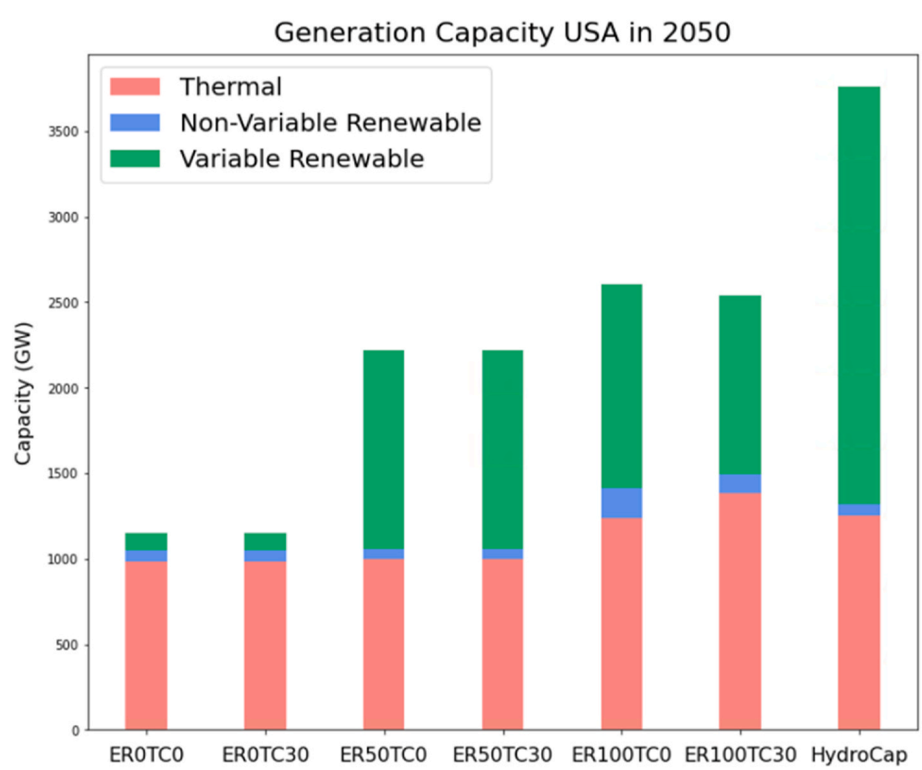
Fig. 3. Installed generation capacity in (A) Canada for BAU (ER0TC0), (B) Canada for net zero (ER100TC0), (C) U.S. for BAU (ER0TC0) and (D) U.S. for net zero (ER100TC0).

Long-term and short-term storage solutions require further analysis but can be implemented to work with variable generation facilities to increase system resilience and flexibility but this analysis is beyond the scope of this study.

Aggregated generation capacities in 2050 in Canada and the U.S. for all six scenarios are shown in Fig. 4A&B, including the restricted hydro



Comparison of Power Generation Capacity - Canada



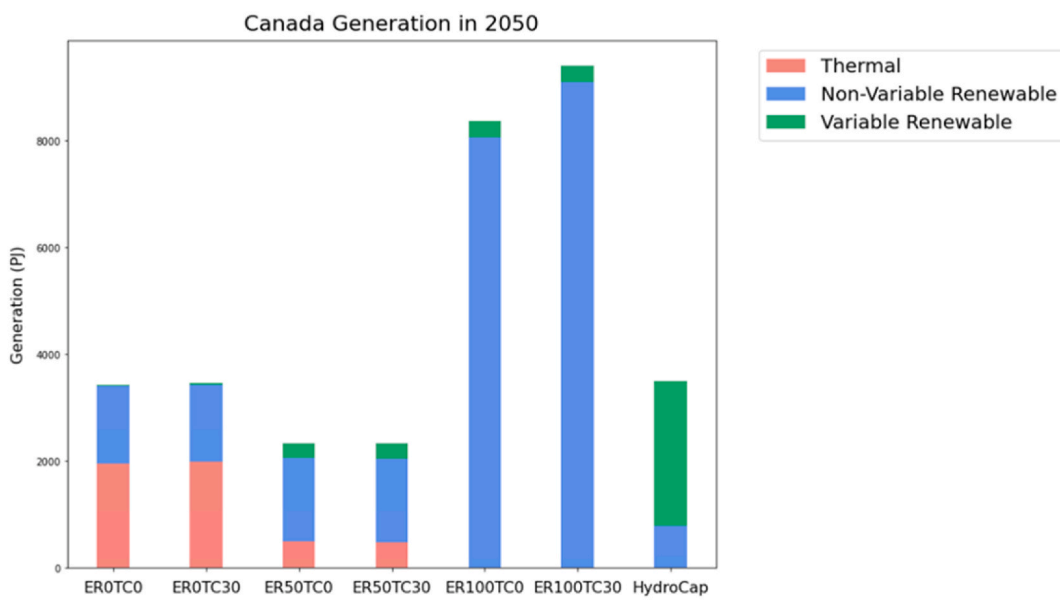
Comparison of Power Generation Capacity - U.S.

Fig. 4. A - comparison of power generation capacity - Canada. B - Comparison of power generation capacity - U.S.

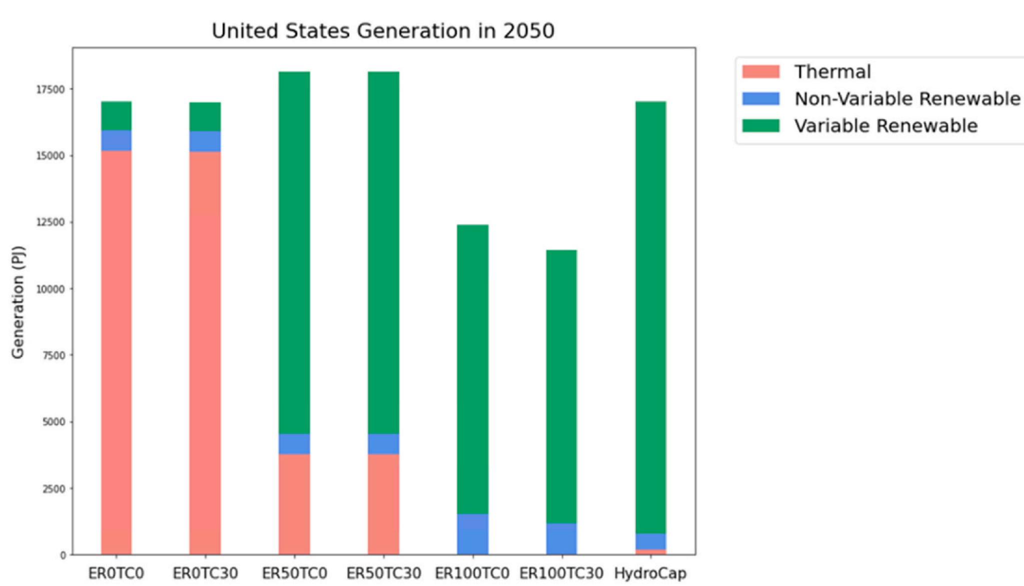
scenario (HydroCap). Final installed system capacity for all net-zero scenarios is at least two and a half times that of the BAU scenario and this is primarily caused by daily and seasonal weather variations affecting variable renewable energy generation. One installed unit of solar or wind capacity will produce significantly less electricity over the course of a day than the level given by its nameplate capacity. The model addresses this issue by installing more capacity in order to meet energy production requirements. Furthermore, as discussed, reserve margin restrictions force minimum amounts of dispatchable capacity to be installed, thereby also contributing to the increased system capacity levels.

Further contributing to the additional installed capacity for net-zero is the reserve margin interaction with transmission capacity. Following a case study for the Baltic Sea region conducted by Henke et al. [98], we do not include transmission as firm capacity. This may overestimate installed capacity. A full analysis of the impact of reserve margin is beyond the scope of this paper but one option for future work is to apply a multiplier on each unit of trade such as was done by Jayadev et al. [36] and de Moura et al. [99]. Another option would be to link the OSeMOSYS results to a power system model for more in-depth analysis.

While future emission targets require significant wind and solar capacity investments, the model does not capture the land requirements associated with this expansion. In the net-zero scenario, wind and solar capacities are roughly 840 GW and 480 GW, respectively, for the U.S. and Canada. Limiting installed hydro capacity increases these figures to roughly 2275 GW and 585 GW, respectively. Building this much renewable capacity will have a significant impact on the land. For reference, the Alta Wind Farm in California has a capacity of roughly 1.5 GW and occupies a land area of 13 km^2 [100], while the Copper Mountain Solar Farm project in Nevada has an installed capacity of 250 MW spread over an area of 5.6 km^2 [101]. Using these projects as a reference we can conservatively expect to require roughly 7000 km^2 of



Comparison of Generation Mixes - Canada



Comparison of Generation Mixes - U.S.

Fig. 5. A - comparison of generation mixes - Canada. B - Comparison of generation mixes - U.S.

wind and 10,000 km^2 of solar for the net-zero case increasing to 19,000 km^2 of wind and 13,000 km^2 of solar for the limited hydro case. To put this into perspective, the total land area of the State of Connecticut is roughly 12,500 km^2 [102] so these are not insignificant land requirements.

The feasibility of accessing and zoning land for renewable energy projects will be highly dependent on population density and geographic restrictions. For example, Texas is projected to have some of the largest wind and solar capacities by 2050 (see detailed table of regional wind and solar capacities in the supplementary materials). From a land availability perspective, this is reasonable due to the abundant land and natural resource quality in Texas. This may not be the case for the aggressive wind capacity addition seen in the Mid-Atlantic states, where the population density is much higher. Moreover, converting large amounts of land to be used for wind and solar generation can have unforeseen consequences on the surrounding flora and fauna, and neighbouring industries. Performing additional nexus modelling with finer spatial and temporal resolution will provide additional insight on the feasibility of our results but is beyond the scope of the current study.

6.2. Generation mix

In the BAU scenario, the majority of generation shifts towards gas. As previously mentioned, the emission penalty is not yet high enough to discourage gas generation, as it remains cheap and dispatchable. However, the emission penalty for coal generation *is* high enough to nearly eliminate it from the generation mix. As coal retires the system builds new, cheap, less carbon-intensive gas capacity instead of utilizing the existing coal capacity. This supports the current trend of phasing out coal power from the generation mix. However, further separating emission penalties by countries and regions may allow for coal generation to persist on a regional basis.

Fig. 5 shows the generation mix for all scenarios and illustrates the importance of dispatchable generation. The BAU scenario shows a generation mix dominated by gas. In the 50% percent emission reduction scenario, there is a significant increase in variable renewable generation in the U.S. and non-variable renewable generation in Canada; however, gas generation still exists as this flexible generation complements the intermittent renewable sources. In the 50% emission reduction scenario there is some overbuild of gas capacity to meet reserve margin requirements.

In the net-zero scenarios renewable energy occupies the majority of the generation mix. The generation mix consists of greater amounts of hydro in the limitless hydro scenarios and mainly wind and solar in the limited hydro scenarios. This occurs because eliminating gas generation from the system to achieve net-zero emission creates a need for emission-free sources, which the system obtains by expanding hydro, wind, and solar capacities. Other non-variable, emission-free sources such as nuclear are also used.

The generation mix in the net-zero scenarios further highlights the value of variable renewable energy sources to meet demand in a low carbon future. The installed capacities and generation of variable renewables for the 50% reduction and net-zero scenarios are shown in Figs. 4 and 5. While in the 50% emission reduction scenario there is still gas generation to complement the variable renewable production, in the net-zero scenarios, the elimination of gas generation means there is a need for dispatchable, low-carbon generation. The model invests in additional hydro when available as this meets both the reserve margin and generation requirements. When hydro is limited, the system invests in backup gas generation but in actual operation this will likely need to be some form of zero emission dispatchable generation.

6.3. Transmission capacity

The installed transmission capacities within the U.S., within Canada, and internationally between the two countries in 2050 are shown in Fig. 6. Transmission within Canada remains constant in all the scenarios, indicating little value in east-west interconnections. The transmission

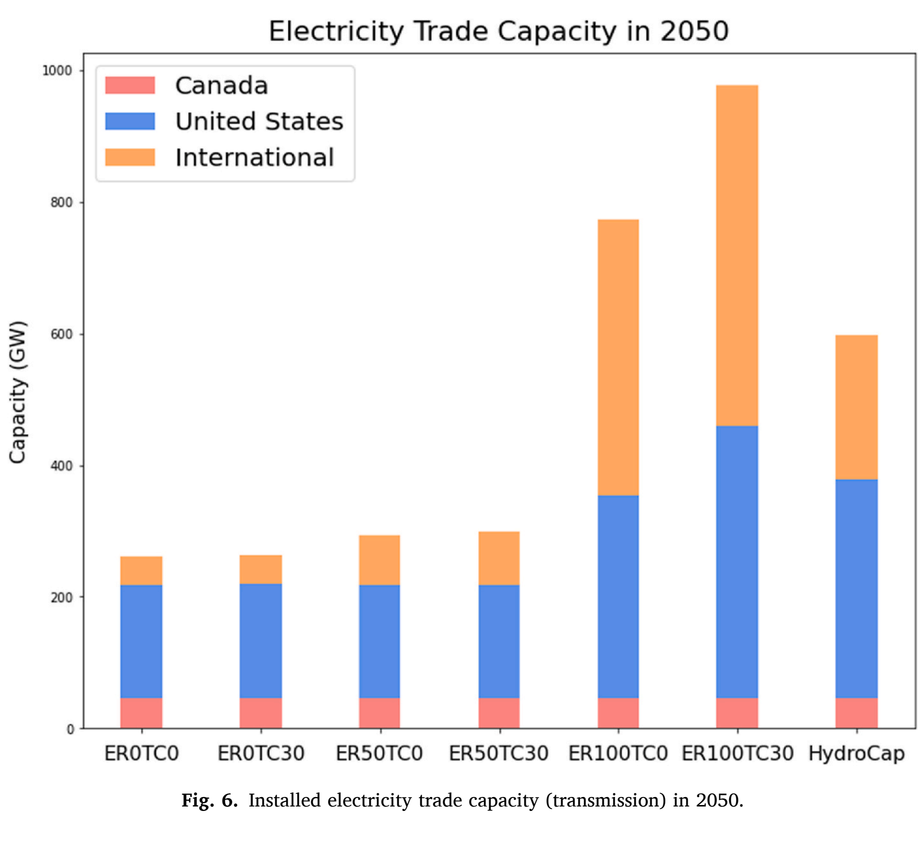


Fig. 6. Installed electricity trade capacity (transmission) in 2050.

capacity within the U.S. and international transmission capacity between the U.S. and Canada both increase by 2050 with the imposition of emission limits to enable trade. Furthermore, the 30% reduction in the transmission capital cost results in visible transmission capacity increases only for international transmission and U.S. national transmission in the aggressive emission reduction, limitless hydro scenario (ER100).

Based on the transmission capacity values in Table A1 in the appendix, international trade capacity increases by 33.75GW in 2050 with the addition of the 50% emission limit (ER50TC0) compared to the ER0TC0. With the reduction in transmission capital cost by 30% (ER50TC30), the results do not change significantly as the international trade capacity in 2050 increases by only 6.8% (5.17GW). In the aggressive climate policy scenario (ER100TC30), the emission reduction requirements are greater and the international and U.S. national trade capacities increase. The international trade capacity increases by 521.1% (176.08GW) and the U.S. national trade capacity increases by 192.6% (160.08GW) compared to the results in ER0TC0. Overall, increased transmission capacity allows renewable generation in certain regions to complement hydro in other regions. Further details on the capacities are provided in the supplementary material.

One interesting feature in the net-zero scenarios is the drastic difference in international transmission when the expansion of hydro is limited to existing and planned capacities. This highlights both the strength of flexible hydro in firming variable renewables, but also the ability to build gas firming capacity in each region if hydro cannot be expanded. Firm, non-emitting technologies will be needed to ensure that the system can operate and provide the benefits of net-zero electricity.

6.4. Cross-border electricity transmission

The increased transmission capacity discussed in Section 6.3 is utilized to allow increased renewable penetration in both the U.S. and Canada. In the BAU scenario the majority of electricity exports are from Canada to the U.S. due to the Canadian hydro-dominated resources and the ability to build gas generation where needed. Between 2019 and

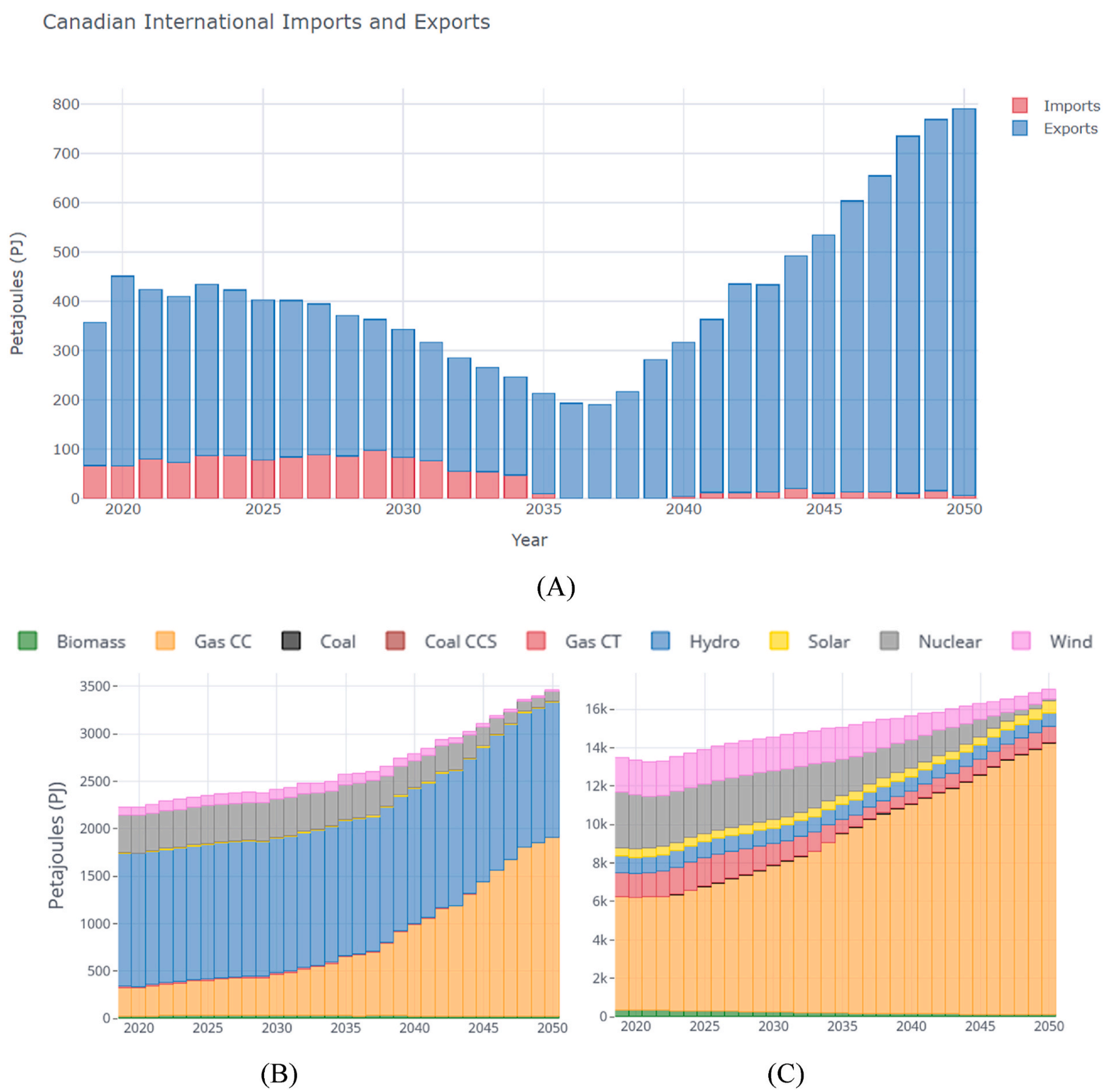


Fig. 7. Transmission increment results (ER0TC30): (A) Canadian exports to/imports from the U.S., (B) Electricity production in Canada and (C) Electricity production in the U.S.

2050 exports from Canada to the U.S. increase by 471.37 PJ indicating the value that large hydro generation facilities in Canada provide. The reduction of transmission costs (ER0TC30) increases international trade between both countries. Canadian exports increase by 3.7% (27.68 PJ) in 2050 when compared to the unreduced cost in the BAU scenario. The U.S. exports increase by 35.3% in 2050 (1.65 PJ) respectively. In Fig. 7A, Canadian imports and exports from 2019 to 2050 are shown for the ER0TC30 scenario.

In the moderate climate policy of ER50TC0, the majority of the exports in 2050 are from the U.S. to Canada (625.38 PJ). Reducing transmission costs has little impact as the U.S. exports only a small amount more (633.29 PJ) for ER50TC30. The investment in gas and wind in the U.S. in the ER50 scenarios leads to higher exports of electricity from the U.S. to Canada (see Fig. 8).

In the aggressive climate policy with limited hydro expansion scenario (ER100TC30), the exports from Canada to the U.S. are higher by about 676.61 PJ in 2050 compared with ER0TC0 while imports from the U.S. to Canada are higher by about 448.73 PJ. This electricity is mainly produced through the hydro investments in Canada and wind investments in the U.S.

Overall, the net-zero scenario increases international transmission, increases intra-U.S. transmission, and has little impact on intra-Canada transmission. Fig. 9B shows the large increase in hydro production in Canada and 9C the corresponding increase in wind and solar generation in the U.S. A 50% emission reduction target causes a large build out of renewable resources primarily in the U.S., with corresponding lower cross-border transmission. With a net-zero emission requirement large

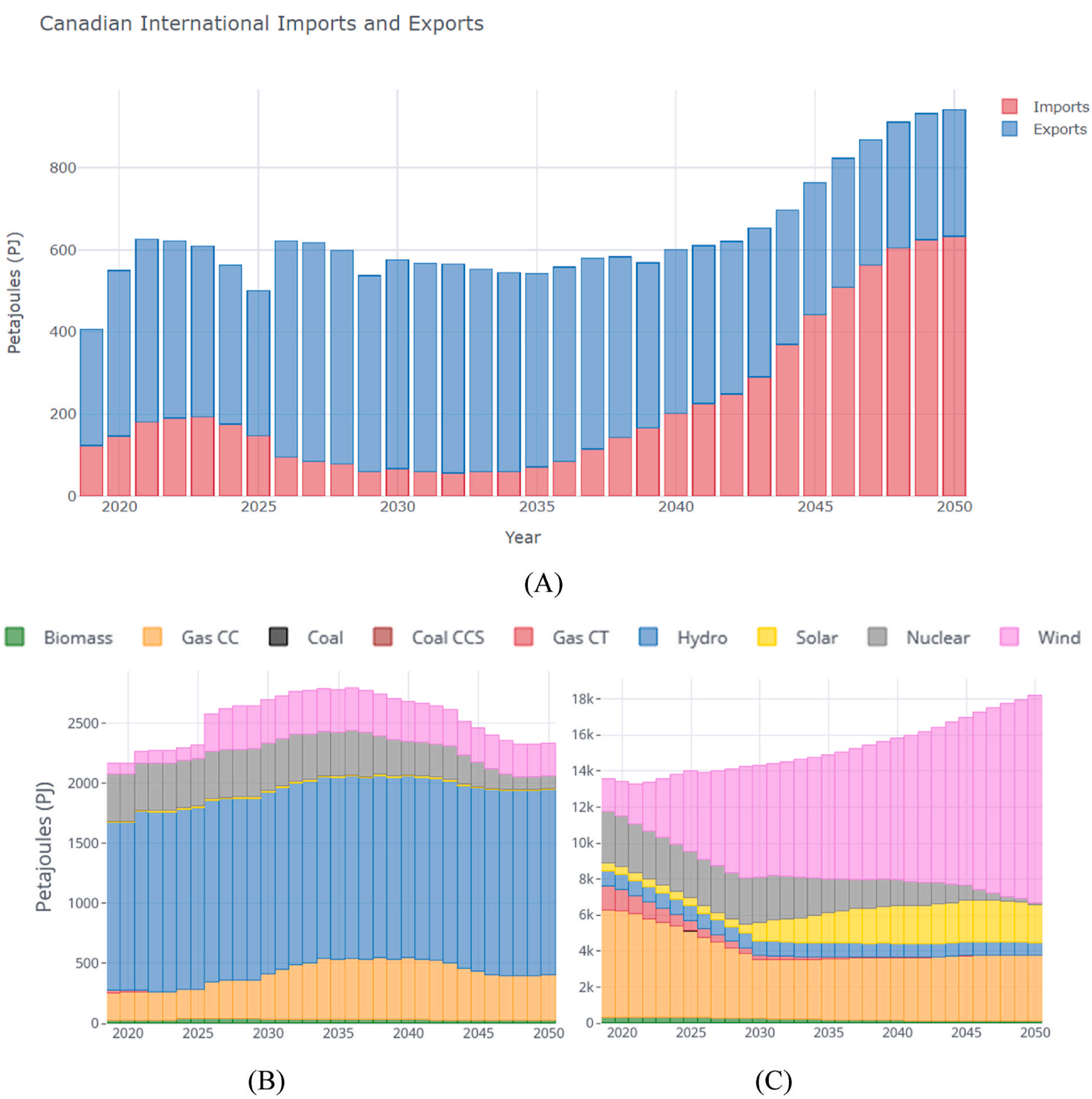


Fig. 8. Transmission increment results (ER50TC30): (A) Canadian exports to/imports from the U.S., (B) Electricity production in Canada and (C) Electricity production in the U.S.

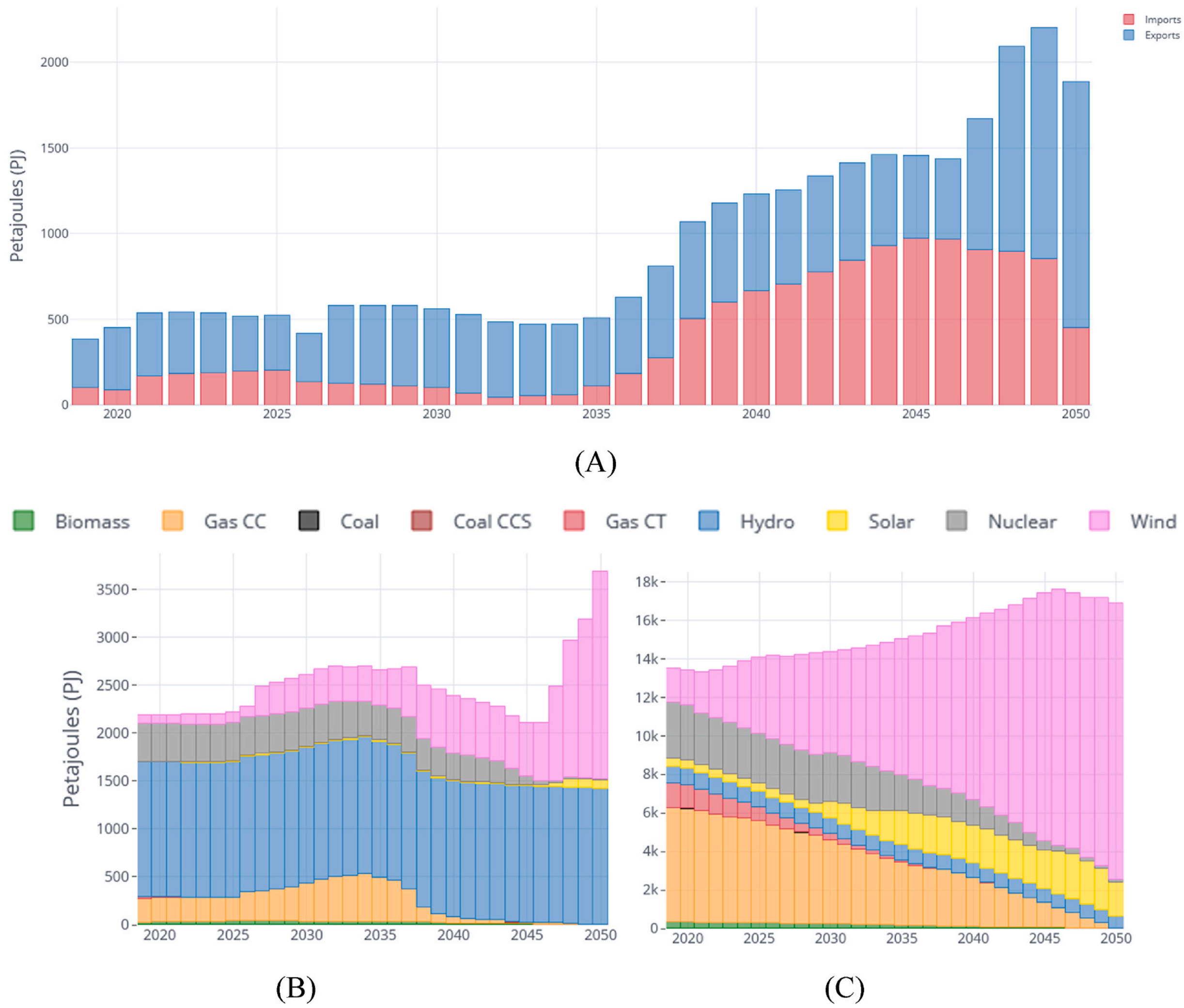


Fig. 9. Transmission increment results (ER100TC30): (A) Canadian exports to/imports from the U.S., (B) Electricity production in Canada and (C) Electricity production in the U.S.

renewable build outs occur in both countries with corresponding larger transmission quantities to balance the variability in these resources.

6.5. Greenhouse gas (GHG) emission

In the BAU scenario the emission penalty is not yet high enough to discourage gas use and therefore emission does not decline significantly. Notably, if no extra intervention is made, 2050 emission will be double 2019 emission, highlighting the need for emission policies.

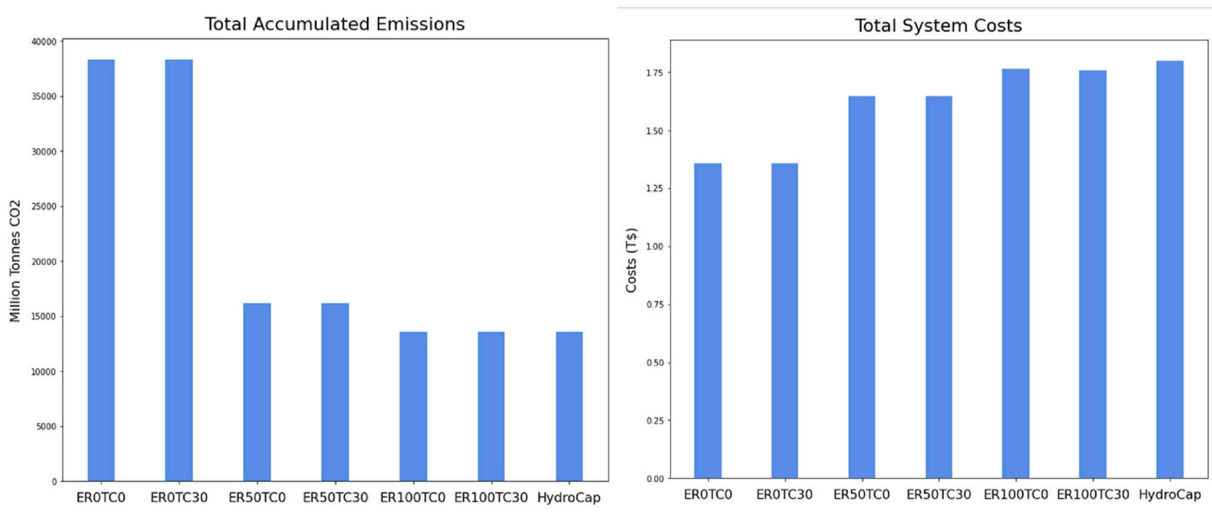
Fig. 10 shows the total system emission across all scenarios. The most dramatic emission reduction happens between the BAU scenario and the 50% emission reduction scenario. The significant decrease in emission is due to implementing limits in the earlier years and these emission limits being applied to all future years. For example, to go from the BAU scenario to a 50% emission reduction by 2030 requires the lifetime emission to be reduced by almost two-thirds. Getting to net-zero in 2050 only reduces the overall lifetime emission by another 15–20%. This indicates that earlier reductions are critical in reducing lifetime emission and postponing emission restrictions will likely result in higher climate impacts.

Although trade capacity increases in the net-zero scenario, and especially in the reduced cost net-zero scenario, transmission capacity investments achieve a given level of emission reductions at a lower cost, but do not lead to deeper emission reductions.

6.6. System costs

The system costs in the model represent the total discounted cost of electricity production in Canada and the U.S. for each scenario. Total system costs, shown in Fig. 10B, show that the gas-dominated BAU scenarios are clearly the cheapest option. To reduce emission levels by 50% in 2030, an 18% increase in spending is required which is a relatively modest increase. Only an additional 7–8% spending increase is required to reach net-zero by 2050. We recognize that it is unlikely that the idealized, least-cost pathway envisioned by the model could actually be realized through real-world policy instruments, but these pathways represent the potential optimal solution within our modelling assumptions.

It might seem, on first glance, that it gets cheaper to reduce emission as we increase policy stringency but this would be an incorrect reading of these figures. As noted above, the 50% emission reduction scenarios reduce lifetime emission by around 65% (~38,000 to ~16,000 Mt) for



(A) (B)

Fig. 10. (A) Total system emissions over the model period and (B) CO2 Emissions for each scenario.

an increased cost of 18–20%. The 100% emission reduction scenarios only reduce the lifetime emission by another ~2000 Mt (from ~16,000 to ~14,000 Mt) for an additional 7–8% of the system cost. The marginal cost of cumulative (over the whole model timeframe) emission reduction is therefore much higher for the net-zero scenario than the 50% reduction scenario.

7. Conclusions

We developed a model of the U.S.-Canada electricity system to analyze the transition towards a decarbonized electricity system. We focused only on the interconnections between Canada and the U.S. using the OSeMOSYS energy system model and evaluated electricity infrastructure pathways from 2019 to 2050. Imposing stricter CO2 emission limits causes the generation mix to transition from predominantly gas to a mixture of variable renewables, non-variable renewables, and gas (if emission limits allow it). Transitioning to net-zero emission requires an increase in the amount of hydro and renewable, zero-carbon generation to provide emission-free electricity for both countries. In our model, this need is met by expanding hydro in Canada for the limitless hydro scenarios, and hydro, wind, and solar in Canada and the U.S. for the limited hydro scenarios. Furthermore, all scenarios heavily rely on gas capacity as a flexible generation source to cheaply meet reserve margin requirements. This highlights the potential for low-carbon dispatchable generation to contribute to the energy mix.

ER0TC0 and ER0TC30 predict that current U.S.-Canada trade, which is somewhat balanced, will shift to have Canada be a major net exporter of electricity by 2050. The unlimited emission in the ER0TC0 and ER0TC30 scenarios allow a higher investment in natural gas in Canada, with corresponding increases in exports to the U.S. When emission is constrained, this balance shifts, with the U.S. exporting significantly more electricity than it imports in the 50% emission reduction scenarios (ER50TC0 & ER50TC30), mainly based on expanded wind and solar in the U.S. Conversely, and relying on expansion of wind generation and consistency of hydro in Canada, when a 100% GHG-free electricity requirement is implemented, energy flow from Canada to the U.S. expands significantly in 2050, highlighting the value of dispatchable low-carbon generation. The sensitivity of exports and imports to GHG targets implies that small differences in policies in different jurisdictions might have significant impacts on the balance of electricity trade, and early action is critical. Finally, we find that small changes in transmission costs do not have a large impact on overall system infrastructure investments, and that transmission expansion is driven more by climate policy (and resulting changes in generation mixes) than by the capital cost of building new transmission. The focus should be on identifying an appropriate generation mix for the combined system and not on transmission per se, as transmission infrastructure will be built to support the emerging generation mix.

Several limitations of our study should be noted. First, increasing variable renewable energy shares in the system will lead to periods of over- and under-production due to weather conditions. The model currently has no way to deal with overproduction periods other than curtailing the generation. Introducing short-term energy storage solutions, such as batteries, or long-term storage solutions, such as power-to-gas to produce hydrogen, may influence generation and capacity mixes. Second, our transmission line capital cost does not take regional geography into account. Applying region-specific cost multipliers to address geographic barriers such as mountains may improve transmission capacity expansion accuracy. For example, the Rocky Mountains stand along the border between the U.S. Northwest and U.S. Mountain North regions. Therefore, we should expect that installing new transmission lines between these two regions will be more costly than doing so between the U.S. Mountain North and U.S. Central regions, for example, whose border runs mostly through prairie land. Lastly, our North American decarbonization study concentrates on Canada and the U.S. because of the limited electricity transmission between Mexico and the U.S [103]. In the future, we plan to include Mexico and calculate optimal electricity generation and transmission investments amongst all the North American countries.

Credit author statement

In this project, I researched and collected data, set up meetings with representatives from the universities working on the project (SFU & UOT). I assigned students to different sections of the project, while assisting in every stage. I started and finished the entire report and studies with the assistance of everyone in the team.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

A. Appendix.

A.1 Reserve Margin Constraint Equation

The following figures show the default and modified reserve margin constraint equation. Highlighted in red is the removal of the fuel summing in the original constraint equation. Highlighted in blue are our additions to force the reserve margin to index over fuels.

```
s.t. RM3_ReserveMargin_Constraint{r in REGION, l in TIMESLICE, y in
YEAR}: sum{f in FUEL, (m,t) in MODExTECHNOLOGYperFUELout[f]}
RateOfActivity[r,l,t,m,y]*OutputActivityRatio[r,t,f,m,y] *
ReserveMarginTagFuel[r,f,y] * ReserveMargin[r,y] <=
sum {t in TECHNOLOGY} ((sum{yy in YEAR: y-yy < OperationalLife[r,t] &&
y-yy>=0} NewCapacity[r,t,yy]) + ResidualCapacity[r,t,y]) *
ReserveMarginTagTechnology[r,t,y] * CapacityToActivityUnit[r,t];
```

Fig. A.1. Default Reserve Margin Constraint Equation.

```
s.t. RM3_ReserveMargin_Constraint{r in REGION, l in TIMESLICE, y in
YEAR, f in FUEL: ReserveMarginTagFuel[r,f,y]>0}: sum{t in TECHNOLOGY,
m in MODEperTECHNOLOGY[t]}
RateOfActivity[r,l,t,m,y]*OutputActivityRatio[r,t,f,m,y] *
ReserveMarginTagFuel[r,f,y] * ReserveMargin[r,y]<= sum {t in
TECHNOLOGY} ((sum{yy in YEAR: y-yy < OperationalLife[r,t] && y-yy>=0}
NewCapacity[r,t,yy])+ ResidualCapacity[r,t,y]) *
ReserveMarginTagTechnology[r,t,f,y] * CapacityToActivityUnit[r,t];
```

Fig. A.2. Modified Reserve Margin Constraint Equation.

A.2 U S.-Canada Transmission Capacity (GW)

Table A.1
U.S.-Canada Transmission Capacity (GW)

	Scenario	Trade Power (GW) 2019	Trade Power (GW) 2030	Trade Power (GW) 2050 - Limitless Hydro	Trade Power (GW) 2050 - Limited Hydro
Canada	ER0TC0	45.78	45.78	45.78	–
U.S.	ER0TC0	172.87	172.87	172.87	–
International	ER0TC0	19.68	19.68	41.81	–
Canada	ER0TC30	45.78	45.78	45.78	–
U.S.	ER0TC30	172.87	172.87	173.24	–
International	ER0TC30	21.58	21.90	44.86	–
Canada	ER50TC0	45.78	45.78	45.78	–
U.S.	ER50TC0	172.87	172.87	172.87	–
International	ER50TC0	21.73	36.05	75.56	–
Canada	ER50TC30	45.78	45.78	45.78	–
U.S.	ER50TC30	172.87	172.87	172.87	–
International	ER50TC30	22.87	39.69	80.73	–
Canada	ER100TC0	45.78	45.78	45.78	–
U.S.	ER100TC0	172.87	172.87	307.92	–
International	ER100TC0	21.73	30.56	419.07	–
Canada	ER100TC30	45.78	45.78	45.78	45.78
U.S.	ER100TC30	172.87	172.87	413.40	332.95
International	ER100TC30	22.22	34.91	518.57	217.89

A.3 U S.-Canada Cross-Border Electricity Transmission (PJ)

Table A.2
U.S.-Canada Exports (PJ)

	Scenario	Export (PJ) 2019	Export (PJ) 2030	Export (PJ) 2050 - Limitless Hydro	Export (PJ) 2050 - Limited Hydro
Canada	ER0TC0	285.36	248.10	756.73	–
U.S.	ER0TC0	64.86	76.21	4.68	–
Canada	ER0TC30	289.63	259.97	784.41	–
U.S.	ER0TC30	66.97	82.84	6.33	–
Canada	ER50TC0	280.98	488.53	312.97	–
U.S.	ER50TC0	101.58	68.39	625.38	–
Canada	ER50TC30	283.11	509.25	308.63	–
U.S.	ER50TC30	122.95	66.94	633.29	–
Canada	ER100TC0	280.98	438.89	5464.88	–

(continued on next page)

Table A.2 (*continued*)

	Scenario	Export (PJ) 2019	Export (PJ) 2030	Export (PJ) 2050 - Limitless Hydro	Export (PJ) 2050 - Limited Hydro
U.S.	ER100TC0	101.58	99.06	0.00	–
Canada	ER100TC30	283.95	445.16	6455.47	1433.34
U.S.	ER100TC30	101.95	97.26	0.00	453.41

A.4 Objective Costs

Table A.3
Total System Cost Results

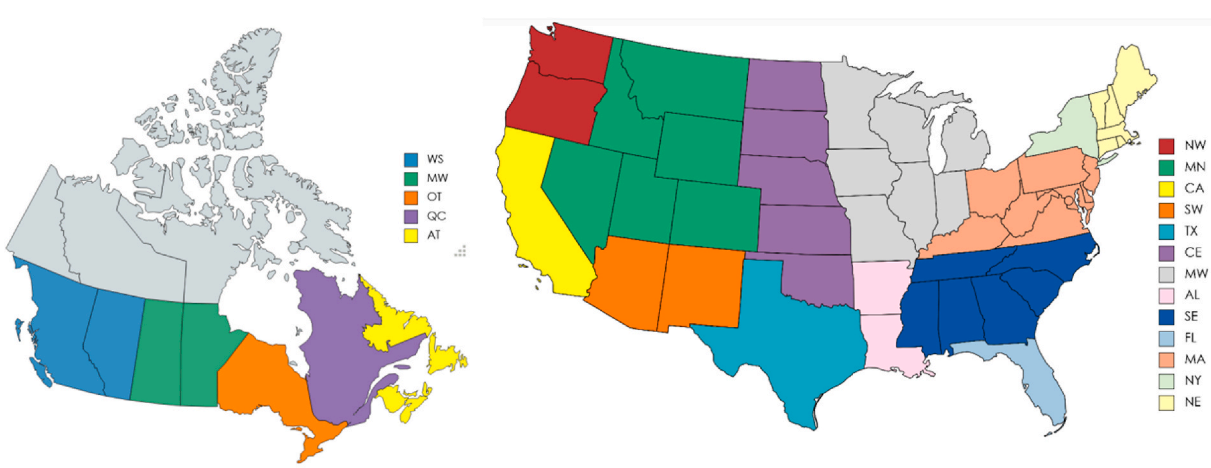
Scenario	Cost (T$">$)
ER0TC0	1.358
ER0TC30	1.358
ER50TC0	1.648
ER50TC30	1.647
ER100TC0	1.765
ER100TC30	1.759
HydroCap	1.801

A.5 Wind and Solar Capacity Results

Table A.4
2050 Installed Wind and Solar Capacity by Region for ER100TC30

Country	Region	Solar Capacity (GW)	Wind Capacity (GW)
Canada	WS	2.31	3.40
	MW	0.00	0.00
	OT	0.00	0.00
	QC	0.00	25.35
	AT	0.00	0.00
United States	NW	2.31	11.64
	CA	34.10	43.12
	MN	2.07	63.26
	SW	12.97	15.60
	CE	8.26	20.19
	TX	126.56	106.30
	MW	0.30	17.78
	AL	13.39	5.23
	MA	64.78	172.21
	SE	110.76	99.59
	FL	52.84	47.68
	NY	0.29	0.08
	NE	0.03	14.75

A.6 Additional Figures



(A) (B)

Fig. A.3. Regional breakdown of (A) Canada (B) United States.

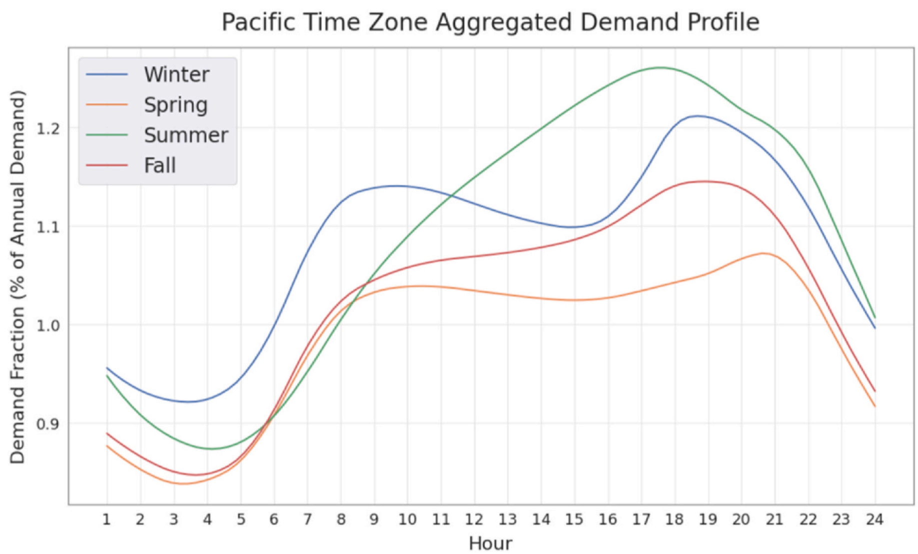


Fig. A.4. Aggregated Demand Profile for Regions in the Pacific Time Zone.

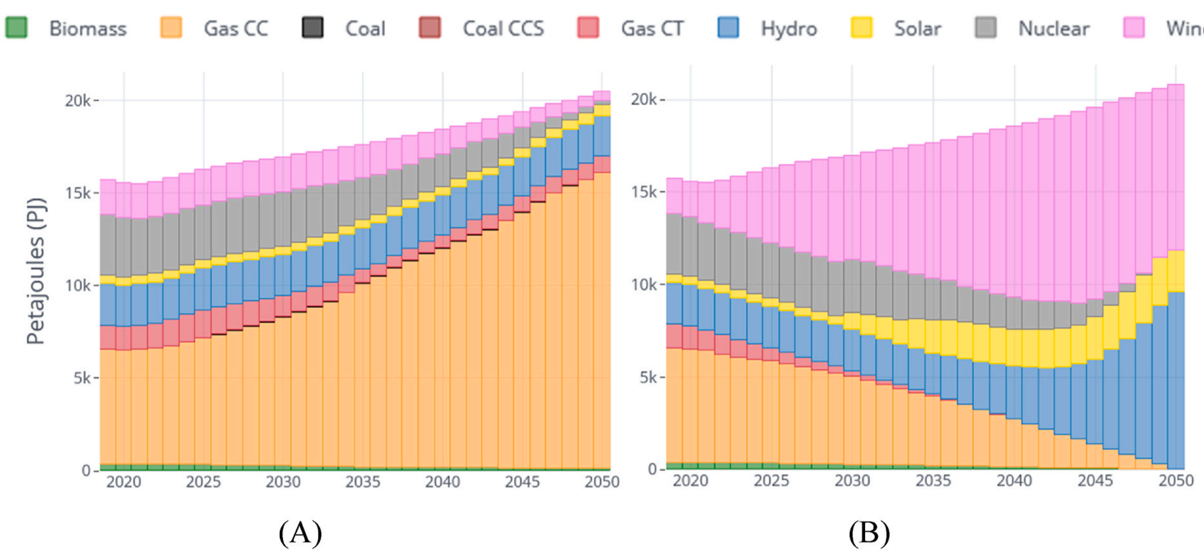


Fig. A.5. System Level Generation (A) Base Scenario ER0TC0 (B) Net-Zero Limit Less Hydro - ER100TC30.

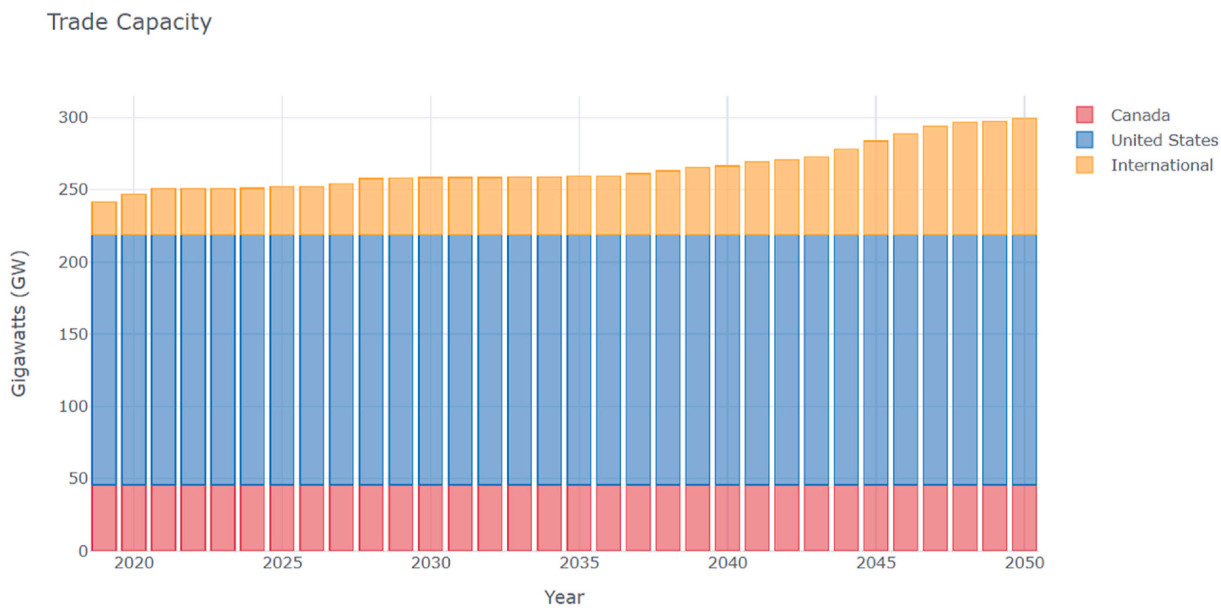


Fig. A.6. ER50TC30 Transmission Capacity (National and International).

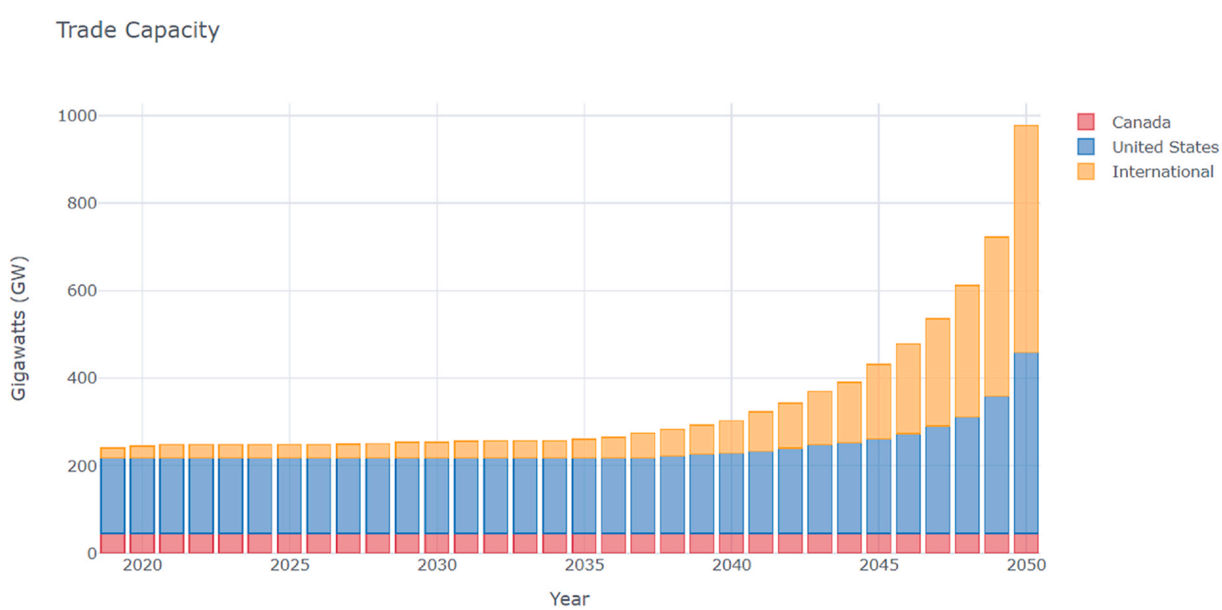


Fig. A.7. Net -Zero Limit Less Hydro - ER100TC30 Transmission Capacity (National and International).

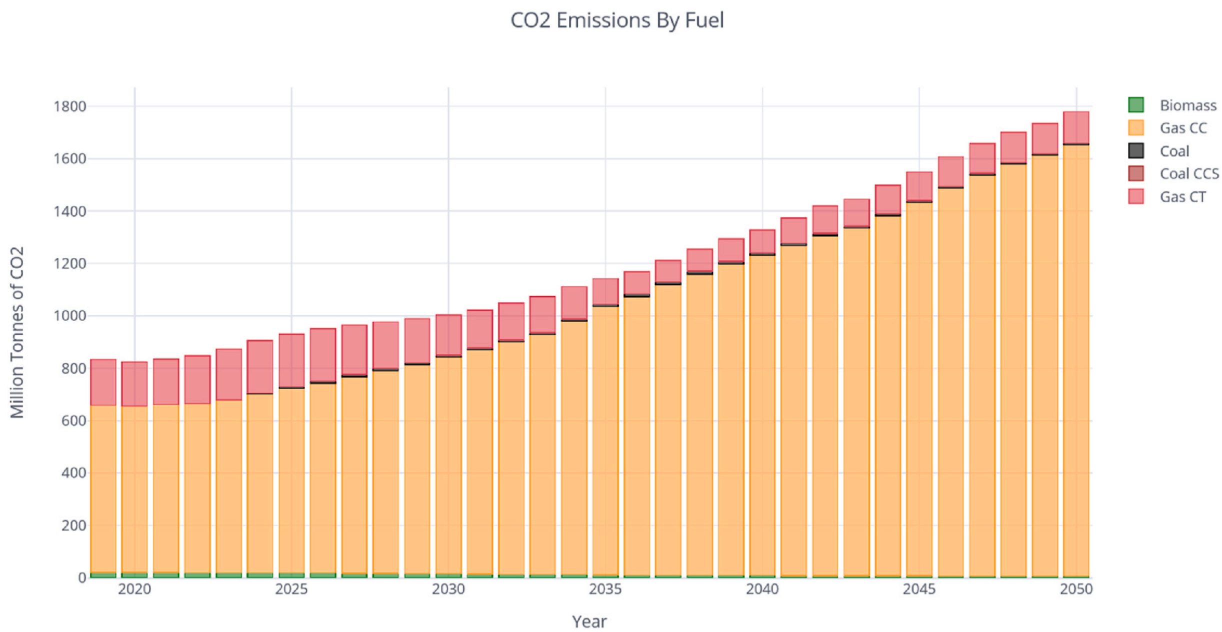


Fig. A.8. Base Scenario Emission Production (ER0TC0).

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Glossary

List & Definition of Abbreviations

Gas CC: Gas Combined Cycle
Gas CT: Gas Combustion Turbine
Coal CCS: Coal Carbon Capture & Storage
ER0TC0: Emission Reduction 0 Transmission Cost Reduction 0%
ER0TC30E: mission Reduction 0 Transmission Cost Reduction 30%
ER50TC0: Emission Reduction 50% Transmission Cost Reduction 0%
ER50TC30: . Emission Reduction 50% Transmission Cost Reduction 30%
ER100TC0: Emission Reduction 100% Transmission Cost Reduction 0%
ER100TC30: Emission Reduction 100% Transmission Cost Reduction 30%