MIT CEEPR
MIT Center for Energy and Environmental Policy Research

Massachusetts Institute of Technology
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139-4307
T: 617 253 3551 F: 617 253 9845
E: ceepr@mit.edu

February 3, 2022

The Honorable Michelle L. Phillips
Secretary
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

RE: Case Number 15-E-0302 – Letter Sharing Research Pertinent to the Champlain Hudson Power Express (CHPE)

Secretary Phillips,

The New York State Energy Research and Development Authority (NYSERDA) recently selected the Champlain Hudson Power Express (CHPE) and the Clean Path NY (CPNY) projects under the Tier 4 process pursuant to the implementation of New York's Climate Leadership and Community Protection Act (CLCPA) and the goal of a zero-emission grid.

We submit this comment to bring to the Commission's attention the results of our research on the potentially valuable contribution transmission connections between New York State and Quebec can make towards achieving the goal of a zero-emission grid. The results were originally published in a working paper titled "Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower," available on the website of the *MIT Center for Energy and Environmental Policy Research*.[1] A peer-reviewed version was published in the journal *Energy Policy* under the title "The Role of Hydropower Reservoirs in Deep Decarbonization Policy."[2] Copies of these papers are attached to this comment letter.

The research analyzes the task of achieving increasingly deep decarbonization goals for the power systems in New York—and also in New England, starting with an 80% reduction in CO2 emissions relative to 1990 levels by 2050, and moving to deeper decarbonization targets of 90%, 99%, and ultimately 100%. We use a capacity expansion and dispatch optimization model to analyze different portfolios of generation investments, with a focus on the role Quebec hydropower might play and the economic trade-offs involved.

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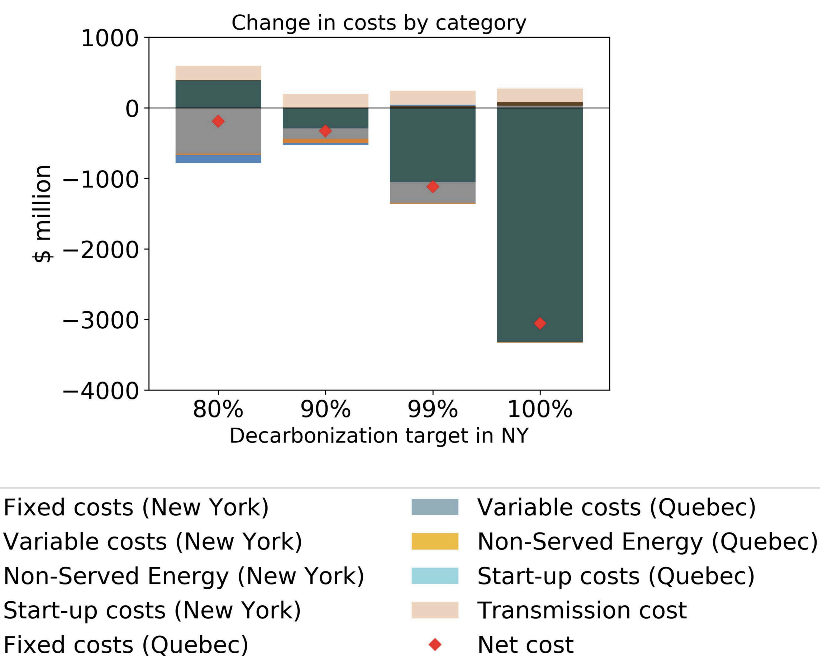
[1] https://ceepr.mit.edu/workingpaper/two-way-trade-in-green-electrons-deep-decarbonization-of-the-northeastern-u-s-and-the-role-of-canadian-hydropower/
[2] https://doi.org/10.1016/j.enpol.2021.112369

One of our key results is that expanded transmission interconnection between New York and Quebec can help achieve deep decarbonization goals at a lower cost. Our analysis focused on a very large, 4 GW expansion of transmission. As shown in the figure below, at an 80% decarbonization level (leftmost column), the investment in additional transmission results in annual net savings of $190 million (red diamond), or $0.50/MWh of annual load. The savings grow as the state moves to deeper levels of decarbonization: moving to 90%, to 99% and to 100%, the net savings are $330 million, $1.121 billion and $3.057 billion per year, respectively. Those translate to net savings of $0.90, $3.00, and $8.00/MWh of annual load. These savings arise primarily from avoided investment in other balancing technologies such as gas plants (with and without Carbon Capture and Storage) and batteries.

Figure. Effect of New Transmission (4 GW) on power system costs in New York and Quebec.[3]



[3] Excerpt from Figure 26 in "Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower," *MIT Center for Energy and Environmental Policy Research Working Paper 2020-003*, attached.

We repeated our analysis for a variety of scenarios for (i) the decarbonization technology pathway, (ii) the cost of renewable generation, (iii) the availability of demand response, and (iv) electrification of end-use sectors, such as transportation and buildings. While the results naturally vary across these scenarios, the basic takeaway remains consistent—additional transmission is valuable.

These results are consistent with the benefit cost analysis provided by the New York State Energy Research and Development Authority (NYSERDA).[4]

A second key result of our analysis is that the cost-optimal use of New York – Quebec transmission will be to balance intermittent renewables, rather than the way it is used today as a source of electricity. Currently, New York treats its transmission interconnect with Quebec as a tool facilitating import of low-carbon electricity. The Tier 4 contract continues this traditional utilization.[5] Quebec exports power, and New York imports it. However, as the New York system shifts to a portfolio of low carbon generation technologies, especially of wind and solar generation, our research shows that the most valuable use of transmission changes. Both New York and Quebec will benefit most if they shift the utilization of the transmission interconnects to balancing tools. In a cost-optimal low-carbon power system, transmission assets are used to flow power to Quebec in hours of excess wind and solar generation in New York State and to flow power to from Quebec to New York in hours of scarcity. This two-way trading of electricity leverages the short- and long-term energy storage capabilities of Quebec's hydro reservoirs. Expanding transmission would help New York take further advantage of existing hydro reservoirs as a balancing resource, facilitating greater deployment and more efficient use of wind and solar in New York. Fully realizing this balancing potential will require appropriate institutional arrangements between New York State and Quebec.

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[4] Case 15-E-0302 Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program Case and a Clean Energy Standard. NYSERDA, Petition Regarding Agreements for Procurement of Tier 4 Renewable Energy Certificates, Appendix C. Cost Analysis, November 30, 2022.

[5] Case 15-E-0302 Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program Case and a Clean Energy Standard. NYSERDA, Petition Regarding Agreements for Procurement of Tier 4 Renewable Energy Certificates, Appendix B. Tier 4 Renewable Energy Certificate Purchase and Sale Agreement between the New York State Energy Research and Development Authority and H.Q. Energy Services (U.S.) Inc., November 30, 2022.

As New York moves forward with its implementation of the CLCPA, it is vital that it look beyond the near-term steps, out towards the ultimate destination. Our research shows that new transmission to Quebec would help New York reach its end-goal of a deeply decarbonized electricity system. Along with laying this physical infrastructure, New York and Quebec would have to begin the work needed on the appropriate institutional arrangements for that destination.

Sincerely,

Emil Dimanchev
Research Affiliate, and PhD Candidate, Norwegian University of Science and Technology

Joshua Hodge
Executive Director

Dr. John Parsons
Associate Director, and Senior Lecturer, Sloan School of Management

Center for Energy and Environmental Policy Research
Massachusetts Institute of Technology

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Working Paper Series

Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower

EMIL DIMANCHEV, JOSHUA HODGE, AND JOHN PARSONS

FEBRUARY 2020

CEEPR WP 2020-003

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower

Emil Dimanchev, Joshua Hodge and John Parsons, MIT CEEPR

February 12, 2020

Abstract

Meeting climate policy targets in the U.S. Northeast will likely require the nearly complete decarbonization of electricity generation. To that end, consideration is being given to expanding imports of hydropower from neighboring Quebec, Canada. We use a capacity expansion and dispatch optimization model to analyze the role Canadian hydro might play, and the economic trade-offs involved. We find that, in a low-carbon future, it is optimal to shift the utilization of the existing hydro and transmission assets away from facilitating one-way export of electricity from Canada to the U.S. and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation. Doing so reduces power system cost by 5-6% depending on the level of decarbonization. In a cost-optimal low-carbon power system, transmission assets are used to flow power to Quebec in hours of excess wind and solar generation and to flow power to the U.S. in hours of scarcity. Therefore, the cost-optimal use of Canadian hydropower is as a complement, rather than a substitute, to deploying low-carbon technologies in the U.S. Expanding transmission capacity enables greater utilization of existing hydro reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy. New transmission also reduces the costs of deep decarbonization. Adding 4 GW of transmission between New England and Quebec is estimated to lower the costs of a zero-emission power system across New England and Quebec by 17-28%.

1 Introduction

Recent policy changes in the Northeast region of the U.S. commit several states to deep decarbonization of the electricity sector. New legislation in New York and Maine mandates 100% clean electricity by 2040 and 2050 respectively. An executive order in Connecticut calls for 100% clean electricity by 2040. A recent bill in Massachusetts contained a goal of economy-wide net zero emissions by 2050. Meeting such climate policy objectives will require decisions about how to design a portfolio of low- or zero-carbon technologies that can meet future electricity demand.

Pathways toward zero-carbon electricity systems tend rely more or less heavily on wind and solar PV generation (Jenkins, Luke, and Thernstrom (2018)). An emerging question is what additional technologies are best suited to compensate for the high variability of wind and solar. The solution may include improved flexibility in demand; long-distance transmission; dispatchable low carbon technologies; power-to-gas; thermal energy storage; new storage technologies; or a high renewable capacity approach (what some have referred to as "overbuilding"): relying on large renewable capacities to deliver enough power even during periods of low wind or solar availability (National Renewable Energy Laboratory (NREL) (2012), Krey et al. (2014), The White House (2016), Clack et al. (2017), McPherson, Johnson, and Strubegger (2018), Brown and O'Sullivan (2019), Sepulveda et al. (2018), Davis et al. (2018), Jenkins, Luke, and Thernstrom (2018), Energy Futures Initiative (2019)). For Northeastern U.S. states, an additional option is the use of hydropower reservoirs in neighboring Quebec.

Although it is widely accepted that wind and solar PV technologies play an important role in state decarbonization plans, the role of hydropower is contested. Existing precedent from Renewable Portfolio Standards (RPS) reveals a preference among states against energy from new hydropower reservoirs but a general acceptance of energy imports from existing dams. For example, New Hampshire excludes any energy from new hydropower facilities from eligibility in its RPS program. New York excludes energy from new reservoir hydro, in-state or imported, from its Clean Energy Standard. Connecticut, Massachusetts and Rhode Island limit additional hydropower project eligibility in their state RPS programs to projects under 30 MW. In Maine, additional hydropower generation projects are RPS-eligible up to 100 MW.[1] However, both New York and Massachusetts have recently moved to significantly

[1]NH: Class IV (Existing Small Hydroelectric) specifies hydro facilities up to 5 MW, provided the generator

increase hydro imports from Quebec. In 2016, Massachusetts passed the Act to Promote Energy Diversity, which required the procurement of renewable energy and included Canadian hydropower as an eligible resource, with a view to meeting the carbon reduction targets set out under the Global Warming Solutions Act (Commonwealth of Massachusetts (2016)). In support of realizing the goals of this act, and pursuant to Section 83D of the Act, the state required its electric distribution companies (EDCs) to competitively solicit proposals for 9,450,000 MWh of clean energy generation (Commonwealth of Massachusetts (2018)). These proposals were subsequently reviewed by an evaluation team established by the Massachusetts Department of Public Utilities consisting of the Massachusetts Department of Energy Resources (DOER) and the EDCs. At the conclusion of the evaluation process, the evaluation team determined that the two highest ranked project portfolios capable of fulfilling Section 83D's objective were the New England Clean Energy Connect (NECEC) project in Maine and the Northern Pass Transmission (NPT) project in New Hampshire (Commonwealth of Massachusetts (2018)). Both of these projects called for the import of approximately 9,450,000 MWh of additional hydropower from Quebec, Canada to the ISO-New England power market of which Massachusetts is a member.

In January 2018, the Massachusetts Department of Public Utilities evaluation team chose the NPT project as the winning bid. Shortly after this announcement, however, the New Hampshire Site Evaluation Committee (NHSEC) voted to deny a Certificate of Site and Facility for NPT. NECEC was then subsequently and conditionally selected by the evaluation team to enter into contract negotiations with the EDCs concurrent with NPT. In March 2018, the EDCs at the direction of DOER, terminated NPT's conditional selection. Upon termination of the NPT selection, NECEC became the sole, winning bid. Under NECEC, a Power Purchase Agreement (PPA) was successfully undertaken between Hydro-Quebec and Massachusetts EDCs (Anderson and Rubin (2019)). Implementation of NECEC, however, has thus far been held up by opposition in Maine to the transmission infrastructure required to realize the project (AP (2019)).

began operation before January 1, 2006 (New Hampshire PUC (2020)); NY: The Clean Energy Standard limits new hydropower eligibility to the following: run-of-river hydro facilities (no new storage impoundment) and hydroelectric upgrades (no new storage impoundment) (NYSERDA (2020)); CT: Small hydro only (up to 30 MW), Class 1 in service after July 1, 2003, no new dams. (Connecticut Department of Energy & Environmental Protection (2020)); MA: Small hydro only (up to 30 MW) [Class 1] in service after December 31, 1997. RI: Small hydro only (up to 30 MW). ME: Hydro generating stations of up to 100 MW (Class 1) in service after September 1, 2005.

1.1 This paper's contribution

This paper addresses three main questions: 1) how deep decarbonization changes the optimal technology portfolio for the power systems in New England, New York, and Quebec, including the optimal electricity trade between regions; 2) how transmission expansion impacts power systems under deep decarbonization; and 3) how transmission expansion impacts power system costs. We explore each of these questions separately for New England and New York using capacity expansion and dispatch modeling for deep decarbonization targets ranging from 80% to 100%.

We show how a heavy reliance on wind and solar PV generation increases the value of balancing resources. In a deeply decarbonized power system it is economical for Quebec's existing hydro facilities to provide a complementary service to variable renewable generation. Shifting the operation of Quebec hydro to balance wind and solar PV results in a very different use of existing transmission lines. Currently, the lines are used almost exclusively to deliver power from Quebec to New England and New York. However, in scenarios of deep decarbonization, it is optimal to dramatically shift the use of the transmission lines toward a two-way flow of power. Flows to Quebec absorb excess wind and solar PV generation in hours when net load (electricity demand after subtracting variable renewable generation) in New England and New York is low or negative. The deeper the decarbonization targets in U.S. states, the more often are transmission lines used to send power north, encouraging the building of wind and solar PV capacity in the U.S. rather than Quebec. Investing in wind and solar in the U.S. and using the transmission capacity and the reservoir hydropower for balancing purposes minimizes power system costs.

This result is important because future power system planning will depend on assumptions about how transmission capacity will be used. The existing transmission lines between Quebec and New England or Quebec and New York are used for exports from Quebec, and current discussions about new lines focuses exclusively on the idea that they will add even more imports into New England and New York.[2] That discussion presents Quebec hydro as a substitute for other low-carbon generation technologies such as wind, solar PV or perhaps nuclear. Our results recast Quebec hydro imports to New England and New York as a complement to the further expansion of other renewables such as wind and solar PV. Elsewhere along the border of the U.S. and Canada, the planning of the Great Northern

[2] Even as the proposed power purchase agreement between Central Maine Power and Hydro Quebec for the use of NECEC makes the schedule of exports contingent on electricity marginal costs in New England.

Transmission Line currently under construction between Manitoba and Minnesota explicitly contemplates swapping excess wind generation from Minnesota in some hours for hydro generation from Manitoba in other hours when wind generation is low (Minnesota Public Utilities Commission (2015)).

In all of our deep decarbonization scenarios, the existing transmission is being used to capacity, and is a binding constraint shaping the choice of the optimal generation portfolio. We therefore analyze the value of expanding transmission capacity between Quebec and New England and between Quebec and New York. Greater transmission capacity allows Quebec's hydropower reservoirs to provide additional balancing services to New England and New York. In many scenarios, the complementary service provided by additional transmission makes it economical to expand wind and solar PV capacity even further, saving on the cost of more expensive alternatives such as gas generation. At an 80% decarbonization target, the cost of new transmission is approximately equal to the savings. At a 99% decarbonization target, the savings exceed the cost, resulting in a net economic benefit of $913 million/year. In a fully decarbonized power system the net savings from new transmission amount to $2.387 billion/year in our Base Case.

A strategy for power system planning across regions includes a variety of considerations not captured in our analysis. We only utilize information about the hourly profile of renewable resources across a single year, where a full analysis would need to incorporate the inter-annual uncertainty. Our analysis does not address how transmission into and out of the regions interacts with other contingencies shaping the security and stability of the grids, nor do we analyze geographic issues shaping installed capacity requirements. In addition, other non-economic factors will also determine which portfolios are optimal in the broadest sense. These will include issues of land-use and siting, for example, which–aside from the relatively minor pecuniary charges embedded in the cost of capacity–do not enter our analysis.

Among those important issues is an assessment of the Greenhouse Gas (GHG) emissions attributable to hydropower. Measures of emissions attributable to the land use change associated with hydro facilities vary widely by the facility and its environment – see Schlömer et al. (2014) and the discussion in Section 2.2 – and applying those data to prospective facilities is contentious. However, our main results do not involve construction of any new facilities. Instead, they call attention to the value created by changing the operating pattern of pre-existing facilities. Therefore, in our optimization we do not attribute any emissions to the hydro generation. Of course, it is possible that the change in operating pattern could drive a change in emissions, whether positive or negative, and that is something worthy of further investigation. Alongside those main results, we present a small number of scenarios in which the optimization yields installation of new hydro capacity. With respect to those scenarios, it would be appropriate to investigate the facility specific value for emissions from land use change and what that means for overall GHG emissions.

1.2 Previous literature on role of reservoir hydropower in decarbonization

Previous research on hydropower reservoirs has demonstrated their capability to balance wind output in Europe (Korpaas et al. (2013), Solvang et al. (2014)) and reduce curtailment of variable renewable energy (Moser et al. (2015)). Schlachtberger et al. (2017) show how transmission expansion between Norway and the rest of Europe can reduce power system costs by balancing variable renewable resources. The flexibility of hydropower reservoirs has also been explored by Wolfgang et al. (2016) who model how the operation of hydropower reservoirs in Norway can change in response to deployment of variable renewable energy.

In a U.S.-Canadian context, Dolter and Rivers (2018) identify valuable transmission investments between Canadian provinces in pursuit of efficient decarbonization of Canada's electricity system, including additional transmission connecting Quebec and Ontario. Tries (2018) documents the value of additional transmission connecting Quebec to New England. Williams et al. (2018) develops alternative deep decarbonization pathways for the Northeastern U.S., and examine the benefits of adding new transmission capacity with Quebec. These pathways also envision some degree of complementarity between Quebec hydro and renewables in the Northeast. However, the pathways in Williams et al. (2018) are developed only as feasible options and not as the outcome of an optimization. Such a user-defined modeling exercise precludes a complete understanding of how a complex system will respond in different scenarios. For instance, Williams et al. (2018) do not model how transmission expansion impacts power plant investment decisions, including any impact it may have on investments in new hydropower reservoirs in Quebec. The study also does not model how cost-effective utilization of transmission changes with deep decarbonization. While the authors assume exogenously that Quebec will maintain historical net export levels, we show that a two-way transmission utilization is economically optimal given our assumptions. Bouffard et al. (2018) use linear optimization to analyze optimal capacity investments across the Northeastern U.S. and Quebec and also identify a shift in the utilization of Quebec's reservoir hydro to a balancing role for the expanded renewable capacity. They also estimate the benefits of regional integration via additional transmission capacity. However, they do not report on the pattern of utilization of the transmission connections. The literature has also not addressed how the role of transmission and the impact of transmission expansion varies by decarbonization level. Our study is also the first to our knowledge to model the role of Quebec hydropower in a 100% decarbonized power system in New England or New York.

The remainder of this paper proceeds as follows. We begin in Section 2 with a brief overview of key features of the current electricity system across the various sub-regions covered in our analysis. Section 3 describes our capacity expansion and dispatch modeling and details our chosen assumptions. Section 4 explores optimal technology portfolios for each sub-region for a variety of decarbonization scenarios, and addresses the many subsidiary questions we posed. Section 5 concludes with our main findings and implications.

2 Overview of the Current Electricity Systems

2.1 New York and New England

Table 1 shows the 2018 profile of capacity and generation by fuel type in the Northeastern U.S. The data is broken out for New York and for the six state New England region since New York's power grid and energy markets are managed by the state's own Independent System Operator (ISO), NYISO, whereas the grid and markets for the six states of New England are managed by a shared ISO, ISO-NE. As it happens, the two electricity markets are of roughly comparable sizes, with New York being slightly larger than New England. New York's average hourly load is 18.6 MW, with a summer peak of 32.5 MW and a winter peak of 24.9 MW, and so a load factor of 1.74. New England's average load is 14.3 MW, with a summer peak of 26.0 MW and a winter peak of 20.7 MW, and so a load factor of 1.81.

The profiles of capacity are also roughly comparable.

- Both regions have minuscule legacy coal capacities that will be completely phased out shortly.

- Both regions have a large volume of capacity and generation fueled by natural gas and/or oil. Most of this is generation solely fueled by natural gas, including combined-cycle units that can efficiently provide baseload, as well as combustion turbines used as peakers. A sizable segment of this capacity, especially in NY, has dual-fired capability, and a small segment is exclusively oil-fired. In both regions, oil is used primarily as a back-up fuel in cases when the available throughput of natural gas is constrained due to high volumes dedicated to heating and related uses.

- Both regions have a sizable volume of hydro capacity and generation, although they differ in the type of hydro as can be seen in the capacity factors. New York's two large operations at Niagara and on the St. Lawrence operate at much higher capacity factors than the many smaller run-of-river plants that otherwise makeup most of the capacity in the two regions. New England has a larger volume of pumped storage capacity.

- Both regions have a sizable volume of nuclear capacity providing baseload generation, although, going forward the capacity in both regions will be reduced relative to the 2018 figures–NY is scheduled to lose roughly 37% of its 2018 capacity when it closes

Table 1: Capacity and Generation by Fuel Type in New York and New England in 2018

New York (NYISO)

Technology by Fuel	Capacity (MW)	Capacity Share	Generation (GWh)	Generation Share	Capacity Factor
Coal	978	2%	692	0%	8%
Natural Gas / Oil	28,061	62%	55,272	34%	22%
Hydro	6,726	15%	29,856	18%	51%
Nuclear	5,848	13%	43,003	26%	84%
Solar	1,303	3%	2,072	1%	18%
Wind	1,827	4%	3,985	2%	25%
Other	548	1%	2,729	2%	57%
Total Region	45,291		137,609	84%	
Net Imports			26,759	16%	
Total Generation			164,368		
Pumping Load			(1,159)		
Net Energy			163,209		

New England (ISONE)

Technology by Fuel	Capacity (MW)	Capacity Share	Generation (GWh)	Generation Share	Capacity Factor
Coal	1,184	3%	1,109	1%	11%
Natural Gas / Oil	24,616	54%	51,676	41%	24%
Hydro	3,784	8%	8,710	7%	26%
Nuclear	4,213	9%	31,385	25%	85%
Solar	2,391	5%	3,436	3%	16%
Wind	1,347	3%	3,374	3%	29%
Other	1,448	3%	6,228	5%	49%
Total Region	38,983		105,918	83%	
Net Imports			21,536	17%	
Total Generation			127,454		
Pumping Load			(1,804)		
Net Energy			125,650		

Sources:

NYISO capacity data is from NYISO, 2018, "Gold Book", Load & Capacity Data, Table III-2, Nameplate Capacity. The solar value includes Behind-the-Meter PV from Table I-9a, p. 26, using an 86% DC-to-AC derate.

NYISO generation data is from NYISO, 2019, "Gold Book", Load & Capacity Data, Figure III-3, 2018 NYCA Energy Production by Fuel Type, p. 78. Behind-the-Meter generationi is estimated based on an 18% capacity factor derived from Tables I-9a and I-9b. Net Imports are from Table III-d, p. 75. Pumping load is estimated from pumped storage generation based on a 70% efficiency.

ISONE capacity data is from ISONE, 2018, CELT Report, Excel Workbook, Table 2.1 Generator List, Nameplate Capacity. Solar capacity is from ISONE, 2018, Final 2018 PV Forecast, p. 11, in order to include Behind-the-Meter solar.

ISONE generation data is from ISONE, 2019, Net Energy and Peak Load by Source.xlsx File ("2018_energy_peak_by_source.xlsx"). Solar generation is from ISONE, 2018, Final 2018 PV Forecast, p. 40, in order to include Behind-the-Meter solar.

Notes:

Natural gas / oil category includes units fueled either by natural gas or by an oil product, or dual-fired.

Hydro includes pumped storage generation.

Other includes a wide variety of generation, including landfill gas, municipal waste, biogas, batteries and flywheels, among others.

Indian Point in 2021 and New England recently retired roughly 17% of its 2018 capacity when it closed the Pilgrim plant in mid-2019.

- Both regions have a small but growing capacity in solar PV and wind.
- Finally, both regions rely on imports to serve a sizable share of their load. Hydro imports from Quebec represent just under 50% of New York's total imports and about 85% for New England. New York also imports from Ontario and from the PJM region on its southern border. Power flows in both directions between New York and New England, although on net, New England is the importer from New York.

Electricity supply in New York and New England is primarily from private generation companies, mostly unbundled from transmission and distribution. However, New York is distinguished by its large public power authority that controls two large hydro projects at Niagara and along the St. Lawrence. Both territories have a number of small municipal or cooperative entities with their own generation. Both territories administer a competitive wholesale market.

The wholesale cost of electricity in NYISO averaged \$44.92/MWh in 2018, while in ISO-NE it was \$43.54/MWh–NYISO (2019) and ISO-NE (2019b). Since these are competitive market prices, they are average short-run marginal costs. These are all-in wholesale market costs, including the energy market, the capacity market and the ancillary services market. They do not include the cost of transmission or distribution, nor any other retail charges. They also do not include any subsidies channeled outside of the wholesale market, which include credits and support to renewables. For example, state support for renewables has often included requirements that load serving entities source renewable power under long-term contracts, and the premium cost of this power is not included in the wholesale market price.

GHG emissions in the electricity sectors of both New York and New England have experienced a long-term decline over the past decades, driven by several factors. Figure 1 shows the trend in New York from 1990 to 2017.

The left-hand axis measures annual generation, and the colored areas show total generation by fuel. The right-hand axis measures annual CO2 emissions in the electricity sector which are indicated by the solid black line with square markers at each year. Total generation is roughly constant, but CO2 emissions decline approximately 63%, from nearly 70 million

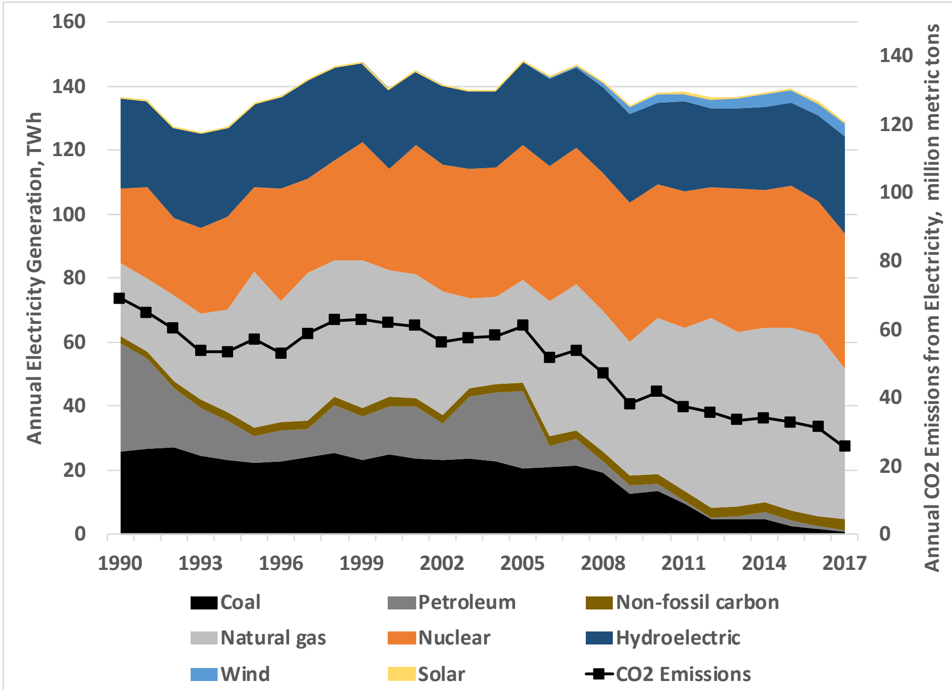

Figure 1: Electricity Generation, Fuel Shares and CO2 Emissions in New York, 1990-2017.

Data source: EIA.

metric tons to less than 26 million. The main driver for this change is fuel substitution: declining generation from coal- and oil-fired plants, and increasing generation by natural gas-fired and by nuclear plants. From 1990 to 2017, coal-fired generation declined by 25 TWh and oil-fired generation by 33 TWh. This produced CO2 emission reductions of 26 million tons from coal-fired generation and 28 million from oil-fired. During the same period, natural gas-fired generation increased by 26 TWh and nuclear generation by 19 TWh. This produced an increase of CO2 emissions of 9 million tons from natural gas-fired generation, and zero from nuclear.

The early substitution of natural gas- for coal- and oil-fired generation followed the development of advanced combined-cycle gas turbine technology that significantly improved heat rates. This was a nationwide trend in which New York took part–see Hartley, Medlock and Rosthal (2008).

The increasing share of nuclear generation is a result of two related developments. The most important of the two is the improved operation of the existing fleet of generation. Between 1990 and 2017, operators of New York's nuclear plants increased the aggregate

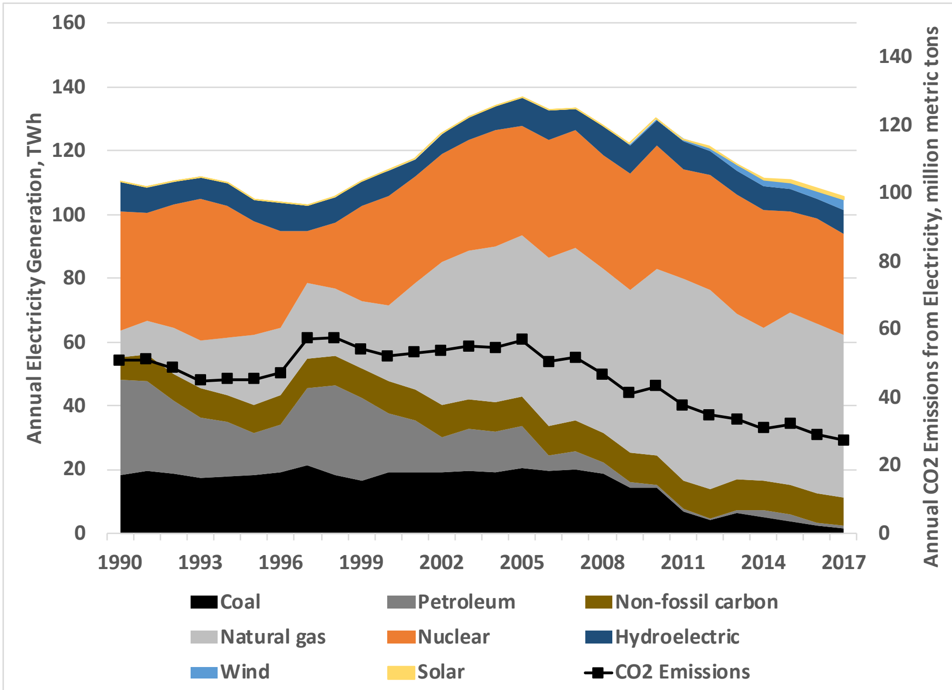

Figure 2: Electricity Generation, Fuel Shares and CO2 Emissions in New England, 1990-2017.

Data source: EIA.

annual capacity factor from 56% to 93%. That yields a 66% increase in generation between 1990 and 2017–i.e., it is comparable to keeping the 1990 capacity factor and increasing capacity by 66%. In addition, owners of several of the plants made investments that increased the capacity of the plants by nearly 500 MW–an increased capacity of 10%.

Since 2008, the low price of natural gas has continued to drive its increased share in generation, aided by continued policy pressure against coal- and oil-fired generation in order to avoid emissions of all kinds. By 2018, the carbon intensity of in-state generation was approximately 200 gCO2/kWh.

The figure also shows the establishment of a small share of generation from wind and solar PV in these later years. Combined, wind and solar increased their generation by less than 5 TWh, which is responsible for a small share of the declining GHG emissions during this period.

Figure 2 shows that New England experienced a similar trend over the past decades. Total generation follows a slightly different path, increasing to a peak during the middle of the time period, but returning to slightly below where it began. CO2 emissions decline approximately 46%, from 51 million metric tons to 28 million. Again, the main driver is fuel substitution: declining generation from coal- and oil-fired plants, and increasing generation by natural gas-fired plants. Coal-fired generation declined by more than 16 TWh and oil-fired generation by nearly 29 TWh. This produced CO2 emission reductions of more than 15 million tons from coal-fired generation and nearly 26 million from oil-fired. During the same period, natural gas-fired generation increased by nearly 48 TWh at a cost of CO2 emissions of 17 million tons.

In New England, nuclear generation declined over this period by nearly 6 TWh, which limited the reductions in CO2 emissions. While operating performance at the New England plants improved during the period, and while three of the reactors had capacity uprates, this was counteracted by several reactor closures early in the period and by a closure at the end of the period. The loss of this zero carbon capacity substantially limited the reduction of carbon emissions. By 2018, the carbon intensity of in-state generation was approximately 200 gCO2/kWh.

New England, too, established a small share of generation from wind and solar PV in the later years. Combined, wind and solar increased their generation by less than 5 TWh, which is responsible for a small share of the declining GHG emissions during this period.

In both New York and New England, implementation of the states' current, ambitious decarbonization targets will require a reversal in the growth of emissions from natural gas and a dramatic acceleration in the growth of wind and solar PV capacity and generation, among other major changes.

2.2 Quebec

Table 2 shows the 2018 profile of capacity and generation by fuel type in Quebec. Almost 90% of the capacity and more than 90% of the generation is hydropower. There is also a small, growing share from wind power alongside a nascent solar sector. Most of the remainder is from a diverse set of small thermal units including a gas turbine plant, an array of biomass (primarily wood products) and waste-to-energy plants, and many small off-grid diesel units. Imports are almost entirely the contract supply from the Churchill Falls hydro facility in neighboring Labrador. Exports are primarily to New York and New England, but also to Ontario and Brunswick.

Table 2: Capacity and Generation by Fuel Type in Quebec in 2018

Quebec					
	Capacity		Generation		Capacity
Technology by Fuel	(MW)	Share	(GWh)	Share	Factor
Hydro	40,438	89%	201,007	96%	57%
Solar	0	0%	2	0%	
Wind	3,432	8%	10,641	5%	35%
Combustibles	1,499	3%	2,212		17%
Total Region	45,369		213,862	102%	
Net Imports			-3,403	-2%	
Total Generation			210,460		

Sources:

Statistics Canada, (2019). From tables 25-10-0022-01 Installed plants, annual generating capacity by type of electricity generation, 25-10-0015-01 Electric power generation, monthly generation by type of electricity, and Table 25-10-0016-01 Electric power generation, monthly receipts, deliveries and availability.

Notes:

Capacity data is year-end 2017. Generation data is for 2018.

Nearly 90% of Quebec's electricity is produced by the province-owned utility Hydro-Quebec which owns more than 90% of the province's hydro generating capacity and nearly 40% of its thermal capacity. The balance of capacity is owned by both industrial companies and private electricity producers. Hydro-Quebec also controls the province's transmission and distribution systems and delivers power to customers under tariffs regulated by the provincial government's energy regulator (Régie de l'énergie).

The retail charge for electricity in Quebec is comparatively low, at approximately \$C31/MWh–De Villemeur and Pineau (2016) and Statistics Canada (2019). However, this is not a competitive market price, but a rate-of-return-regulated price. It incorporates an assessment of the cost of Hydro-Québec's so-called Heritage Pool of hydro resources, together with the incurred cost of other resources. This is far below the average wholesale market price of power in neighboring regions, including the province of Ontario as well as the U.S. regions of New England and New York. Because the prices in the neighboring territories are derived from fundamentally different regulatory regimes, it is not appropriate to compare them directly. Later, when we present modeling results and discuss costs, it will be important to recognize that the cost numbers produced by the model are average incremental costs, and are not directly comparable to Quebec's regulated customer charges.

Due to the dominance of hydropower in Quebec, the GHG emissions intensity of the electricity sector is very low–Canada's National Inventory, reports it at less than 2 gCO2eq/kWh in 2017–Evironment and Climate Change Canada (2019). Quebec has nevertheless taken steps to reduce the intensity by closing a fossil-fuel fired plant and expanding renewables. Between 1990 and 2017, emissions fell by 84%, from 1.495 down to 0.243 million tons CO2eq. In the future, connecting more communities to the grid will allow closing additional diesel units–see Hydro-Québec (2018).

In evaluating the GHG emissions associated with hydropower, we need to appreciate the distinction between direct (short-term marginal) and indirect emissions. Like other renewables, hydropower has zero direct emissions and a small amount of indirect emissions attributable to the infrastructure and the supply chain. National inventories record these indirect emissions in the economic sector where they are produced, and not in the electricity sector. Certain GHG policies, like a cap-and-trade system or a carbon tax, are often administered with a focus on direct emissions alone, as exemplified by the Western Climate initiative cap-and-trade system that Quebec operates with California. So long as coverage is reasonably comprehensive, indirect emissions in one sector are captured by coverage of the sector where the emissions are directly produced. Policy analysis therefore often uses calculations of direct emissions alone. However, hydropower also produces biogenic CO2 and methane emissions arising from the change in land use associated with construction and operation of a hydro facility and the resulting change in the short-term carbon cycle. These can vary greatly by the geography, climate and other features of a facility. In national inventories, these biogenic emissions should be captured in the land use, land use change and forestry (LULUCF) sector, although protocols for doing so are not yet well established. As of yet, this sector is not typically incorporated into broad-based policies like a cap-and-trade or carbon tax. Therefore, it is important that policy analyses like ours give the matter specific regard.

Doing so is complicated by the extreme variation in estimated biogenic emissions reported for different hydro facilities. Figure 3 shows estimates assembled by the IPCC (AR5 2014) of the full lifecycle (direct plus all indirect) emission intensities of a set of electric generating technologies. The solid markers are the median values for each technology, while the whiskers identify the minimum and maximum values. Renewables and nuclear show small positive median emission intensities due to indirect emissions associated with infrastructure and the supply chain. The figure shows hydropower's median emission intensity is comparable to that of other renewables, but with a strikingly large range. The maximum is far above the intensity of fossil fuel sources. This highlights the facility specific information needed to

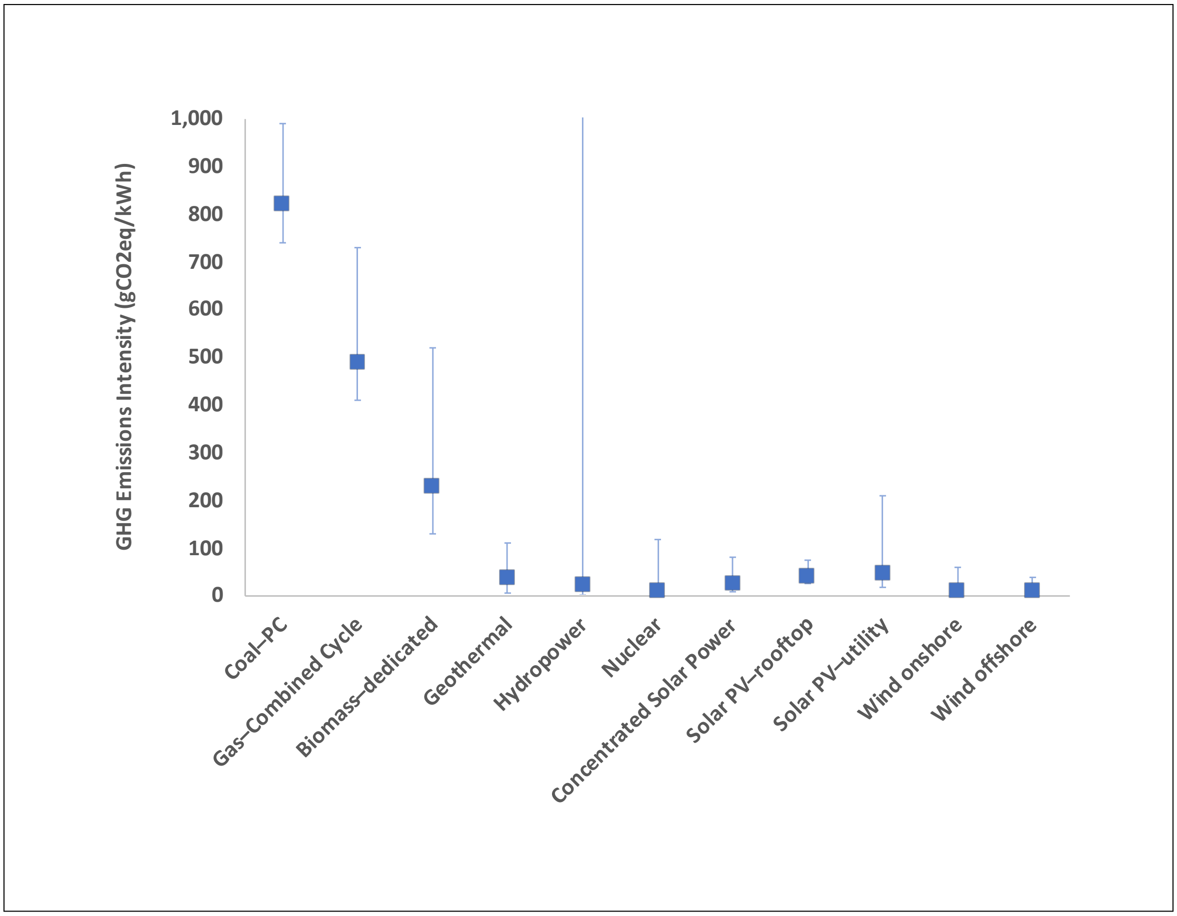

Figure 3: Estimates of Life-cycle GHG Emissions Intensity for Alternative Generation Technologies.

Data source: Schlömer et al. (2014)

evaluate the lifecycle emissions of a hydropower project.

The situation is complicated by the difficulty of calculating the change in land use emissions associated with hydro facilities. The primary focus of research has been on measuring areal emissions of CO2 and CH4 at a reservoir–gross emissions–and calculating the change from what emissions would have been without the reservoir–net emissions. There are important difficulties involved in making these measurements. In addition, these measurements do not capture the whole picture. Not all of the net areal emissions measured at a reservoir accurately represents a net contribution to atmospheric concentrations, since some of the carbon reflected in this measurement would have been returned to the atmosphere elsewhere had it not been returned at this location. At the same time, there are other changes to the carbon cycle that are not measured at that point and which may represent net contributions. For example, sedimentation at the reservoir can temporarily sequester carbon, but it could also yield a net contribution to atmospheric concentrations if it is ultimately dredged and depending upon what is done with the product of the dredging–see Hertwich (2013).

3 Methodology

3.1 Modeling approach

We employ the capacity expansion and dispatch model GenX, described in detail by Jenkins and Sepulveda (2017). GenX is a constrained optimization model that determines the least-cost mix of generation, storage, and demand response investments, as well as the least-cost set of operational decisions, to meet electricity demand at all chosen time periods. We parameterize and configure the model to represent a power system encompassing New England, New York, and Quebec in 2050. The power system is modeled at an hourly resolution, with GenX optimizing electricity supply for all 8760 hours of the year. Our chosen configuration represents important constraints on the operation of thermal plants and reservoir hydro such as ramping limits but we do not model frequency regulation or operating reserve requirements. The configuration and parameterization of the model is described in detail below.

The configuration described below forms our Base Case set of assumptions, unless otherwise specified. The impact of alternative assumptions is explored in Section 4.3.

3.2 Network Topology

We model a three-region network encompassing New England, New York, and Quebec as shown in Figure 4. Each region is treated as a copper plate, with no representation of intra-regional transmission or distribution. Inter-regional transmission is included between New England and Quebec and between New York and Quebec, respectively. We omit existing transmission between New England and New York to specifically explore the interaction between U.S. Northeastern regions and Quebec.

Current transmission lines allow flows from Quebec to New England up to 2.225 GW, and flows from New England to Quebec of 2.17 GW (these capacities account for the Phase II and Highgate transmission corridors) (Hydro Quebec TransEnergie (2017)). Current capacity between Quebec and New York allows flows from the former to the latter of 2 GW and flows in the opposite direction of 1.1 GW. For the purpose of this study, we assume that flow capacities are identical in both directions and equal to 2.225 GW for Quebec-New England and 2 GW for Quebec-New York. In Section 4, we present scenarios that show the impact of expanding these transmission capacities beyond their current values.

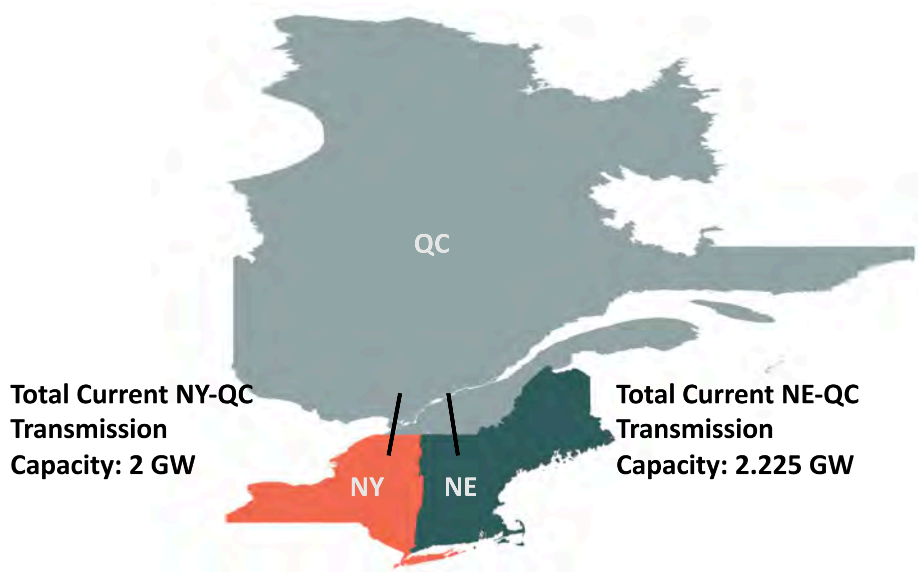

Figure 4: Power system topology

3.3 Power technologies

Our capacity expansion modeling includes existing electricity generation capacity as well as a choice of new technologies that can be deployed. For New England and New York, we combine existing capacity data from U.S. Energy Information Administration (2019b) with typical plant lifetime assumptions from Logan et al. (2017) to determine the amount of power capacity by technology that would be available in 2050 (Table 3). In addition, we assume offshore wind capacities consistent with current state-level mandates.

Table 3: Existing capacity estimated in 2050 (MW)

Technology	New England	New York	Quebec
Run-of-river hydroelectric	853	3,939	
Pumped storage hydroelectric	1,768	1,407	
Combined-cycle gas turbine	9,628	4,702	
Open-cycle gas turbine	746	1,304	
Nuclear	3,500	2,000	
Reservoir hydroelectric			41,108

Existing nuclear facilities will be at or beyond the end of their typical 60-year lifetime in 2050. For these plants, we assume a level of 2050 capacity consistent with the 2019 Annual Energy Outlook by the U.S. Energy Information Administration (2019a), which assumes lifetime extensions for nuclear capacity equivalent to 3,500 and 2,000 MW in New England and New

York respectively. Section 4.3 shows results from additional scenarios that assume all nuclear plants in the region are closed by 2050. Our system-wide cost results in Section 4 include any nuclear lifetime extension costs, which we assume to be 112 \$/kW/y based on European Commission Joint Research Center (JRC) (2014) and calculations reported in Fratto-Oyler and Parsons (2018). Several technology categories are excluded from the model, including plants using Municipal Solid Waste, Oil, and Wood biomass. While biomass plants may play a role in a deeply decarbonized power system, it is uncertain whether such plants will be categorized as carbon neutral in the future (Sterman, Siegel, and Rooney-Varga (2018)), how land use practices and costs may change, and whether existing plants will be granted lifetime extensions.

For Quebec, we begin with Hydro Quebec's existing capacity of 36,653 MW (including reservoir and run-of-river hydro, using plant data from Hydro Quebec (2019a) and decommissioning dates from OATI (2019). We determine the amount of capacity available in 2050 using commissioning dates from Hydro Quebec (2019a) and a 100-year typical lifetime assumption from Logan et al. (2017). For plants where commission dates vary by individual units, we use the last commissioning date. Due to this assumption, 1,218 MW of existing capacity is assumed to no longer be available in 2050. Additionally, we include Churchill Falls in Quebec's total hydro capacity therefore increasing it by 5,428 MW (Hydro Quebec (2019c)). We further include the 245 MW Romaine-4 project currently under development. The resulting estimated total 2050 reservoir hydro capacity in Quebec is 41,108 MW. We include no other existing capacity in our model, therefore excluding independent power producer hydro capacity (which accounts for differences between our assumed existing hydro capacity and that reported in Figure 2) and the current wind and biomass capacities (see Section 2.2).

Technology cost data is sourced from National Renewable Energy Laboratory (2019a) using 2050 costs based on medium-cost future trajectories, unless otherwise specified. New power technologies and their assumed fixed costs and associated financial parameters are listed in Table 4. The Weighted Average Cost of Capital (WACC) for Li-ion batteries is calculated based on financial assumptions from National Renewable Energy Laboratory (2019a) as well as debt fraction and capital recovery period from Lazard (2018). Variable costs and heat rates are displayed in Table 5. Start-up costs are shown in Table 6 and are sourced from Massachusetts Institute of Technology (2018).

Table 4: Power Technology Investment Costs in 2050

Technology	Overnight Cost ($/kW)	Construction Finance Factor	Capex ($/kW)	WACC	Capital Recovery Period (years)	Project Finance Factor	Investment Cost ($/MW/y)
Open-cycle gas turbine	769	1.02	786	2.7%	30	1.11	422,819
Combined-cycle gas turbine	907	1.02	927	2.7%	30	1.11	50,474
Wind onshore	1,685	1.02	1,722	2.4%	30	1.05	84,912
Wind offshore	1,956	1.40	2,739	2.4%	30	1.07	137,648
Solar PV	858	1.01	870	2.4%	30	1.05	42,878
Battery			1,759	7.2%	20	1.05	176,752
Carbon-capture and storage (CCGT)	1,660	1.02	1,697	2.7%	30	1.11	92,388
Reservoir hydro	5,217	1.02	5,333	0.3%	30	1.08	200,038

Table 5: Variable Costs and Heat Rates for Power Technologies in 2050

Technology	O&M cost ($/MW/y)	Non-fuel variable cost ($/MWh)	Fuel cost, new plants ($/MWh)	Fuel price ($/MMBtu)	Heat rate, new plants (MMBtu/MWh)	Heat rate, existing plants (MMBtu/MWh)
Open-cycle gas turbine	53,630	7.54	18.78	5.13	9.750	11.176
Combined-cycle gas turbine	12,018	7.03	49.99	5.13	6.430	7.649
Nuclear	10,387	2.72	32.96	0.69	10.460	10.459
Wind onshore	99,197	2.27	7.20			
Wind offshore	38,775					
Solar PV	142,675					
Pumped hydro	7,280					
Battery	5,980	5.40				
Demand response	0	0.00				
Carbon-capture and storage (CCGT)	33,056	7.05	38.40	5.13	7.490	
Reservoir hydro	29,312					
Run-of-river hydro	29,312					

Table 6: Start-up Costs

Technology	Start-up cost ($/start)	Start-up fuel requirement (MMBtu/start)
Open-cycle gas turbine	16,000	0.18772
Combined-cycle gas turbine	30,000	0.58947
Nuclear	1,000,000	0.58947
Carbon-capture and storage (CCGT)	45,000	0.58947

Non-fuel OM costs are assumed to be the same for new and existing plants of the same type. However, existing capacity incurs higher fuel costs due to lower efficiency. Heat rates for existing plants are sourced from U.S. Energy Information Administration (2019c) and are also listed in Table 5. Costs for onshore and offshore wind represent averages across National Renewable Energy Laboratory (NREL) resource groups weighted by the available potential capacity National Renewable Energy Laboratory (2019a). Reservoir hydro costs represent NREL 2050 estimates for New Stream Development for large dams with head greater than 30 feet and capacity greater than 10 MW as the category most representative of potential development in Quebec. Fuel price costs for 2050 are based on U.S. Energy Information Administration (2019a).

We also include demand-side electricity resources. A demand response technology allows 5% of load to be shifted within a six-hour window (Section 4.3 provides additional results assuming a 20% demand response capability). This demand response is assumed to cost $20/MWh, representative of the costs of shifting load from air conditioning, residential hot water, and electric vehicle charging Dyson et al. (2015). We further assume that electricity demand can be curtailed at a cost of non-served energy of $15,000/MWh.

New capacity investments in New England and New York are assumed to be possible for all technologies with the exception of nuclear, run-of-river hydro, pumped hydro, and reservoir hydro, as we do not assume future investments in these technologies. In Quebec, new investments are assumed to be possible in new reservoir hydro, solar, onshore wind, or battery storage.

Storage technologies, including pumped hydropower, battery storage, and reservoir hydropower, are further parameterized based on their efficiencies and duration. For all storage technologies, we assume charging and discharging single-trip efficiencies of 90%. Reservoir hydro discharge efficiency is factored into hydro flow data provided by Hydro Quebec (2019b). We assume no self-discharge for all storage technologies. Our included battery technology has an 8-hour storage capacity (a power-to-energy ratio of 0.125 MW/MWh). Pumped hydro is assumed to have a power-to-energy ratio of 0.083 MW/MWh (equivalent to 12-hour storage capacity). For reservoir hydro, the storage capacity is based on the aggregate size of Hydro Quebec's reservoirs of 175.5 TWh (Hydro Quebec (2019d)). We estimate a power-to-energy ratio of approximately 209 MW/TWh, derived by dividing the total existing Hydro Quebec generating capacity (combining reservoir and run-of-river) estimated above to equal 36,653 MW by the reservoir energy capacity of 175.5 TWh (Hydro Quebec (2019b)).

Table 7: Canadian Hydropower Project Costs

Project	Capacity (MW)	Cost ($US billion)	Capital Cost ($/kW)
Site C	1,132	8.24	7,279
Keeyask	695	6.70	9,640
Muskrat falls	824	9.78	11,869
Romaine, QC	1,550	6.50	4,194
Yellow Falls, ON	16	0.08	4,861
Saskatoon Weir	6	0.05	8,206
Canyon Creek, AL	75	0.15	2,053
Peter Sutherland, ON	28	0.23	8,251
Boulder Creek, BC	25	0.10	3,832
Upper Lillooet River, BC	81	0.27	3,287
Big Silver Creek, BC	41	0.16	3,907
Jimmie Creek, BC	62	0.17	2,819
Tretheway Creek	21	0.08	3,759
Waneta facility, BC	355	0.69	1,952

Note: We assume a CAD/USD rate of 1.2986

Hydropower costs exhibit high variability due to relatively high site-specificity. In Table 7, we compile costs on Canadian hydropower projects commissioned or in progress over the last five years based on financial reports or other official sources[3]. The average capital cost is $5,422/kW, which is approximately in line with our assumed cost based on National Renewable Energy Laboratory (2019a).

3.4 Operational constraints

We configure GenX to simulate inter-temporal operational constraints for power generating technologies. The model includes specifications for ramping speed, minimum power output, down-times, and up-times as specified in Table 8. Additionally, we represent unit commitment, accounting for start and stop decisions for all thermal technologies, using a linearized clustering method as described in Jenkins and Sepulveda (2017). Operational constraints for thermal plants are sourced from Massachusetts Institute of Technology (2018).

[3]Sources for Site C, Keeyask, and Muskrat Falls: Goulding and Jarome (2019); Romaine: Hydro-Québec (2018); Yellow Falls: Boralex (2019); Saskatoon Weir: City of Saskatoon (2020); Canyon Creek: Alberta Government (2020); Peter Sutherland: Ontario Power Generation (2020); Boulder Creek and Upper Lillooet River: Innergex Renewable Energy Inc (2018); Big Silver Creek: Innergex Renewable Energy Inc (2017); Jimmie Creek: Alterra Power Corp (2014); Waneta facility: Columbia Power (2020)

Table 8: Operational Constraints on Power Generation Technologies

Technology	Maximum ramp up/down (% of capacity/hr)	Minimum up-time (hours)	Minimum down-time (hours)	Minimum output (% of capacity)
OCGT	70%	1	1	24%
CCGT	70%	5	6	38%
CCGT CCS	70%	12	24	30%
Nuclear	25%	36	36	50%
Reservoir hydro	14%			27%
Run-of-river hydro	100%			5%

3.5 Modeling hydropower in Quebec

We model the operation of the Quebec hydropower system as a single unit, with a generation capacity equal to the combined capacity of reservoir and run-of-river hydro in Quebec in 2050 and with reservoir capacity equal to the combined capacity of reservoirs. We configure the reservoir based on assumptions sourced from Hydro Quebec (2019b). We assume that the year begins with the reservoir 70% full. Hydro in-flows are provided at a monthly resolution by Hydro Quebec (2019b) based on average long-term historical hydrological conditions. Figure 5 illustrates the monthly variability. The operation of the reservoir is optimized through the year based on perfect foresight on these inflows and the power demand, subject to a number of constraints. Hydro generation must run at least at 27% of its capacity to account for downstream ecological management and transmission grid stability constraints. We also constrain the ramping speed of reservoir hydro to 14% of total capacity per hour, in line with current operational practices and constraints. Although we do not explicitly model stochastic optimization in the face of uncertainty, we impose two additional constraints that reflect how uncertainty should constrain the optimization. First, we require that the reservoir be not more than 55% full at the beginning of the Spring (specified in the model as May 1), a level deemed appropriate to reliably absorb spring flows. Second, we require that the reservoir again be 70% full at the end of the year, reflecting the normal precaution against inter-annual uncertainty in flows. Previous research exploring the ability of Norwegian reservoirs to balance renewable intermittency found that a simplified approach such as the one employed here compares well with a stochastic and bottom-up representation (Korpaas et al. (2013)).

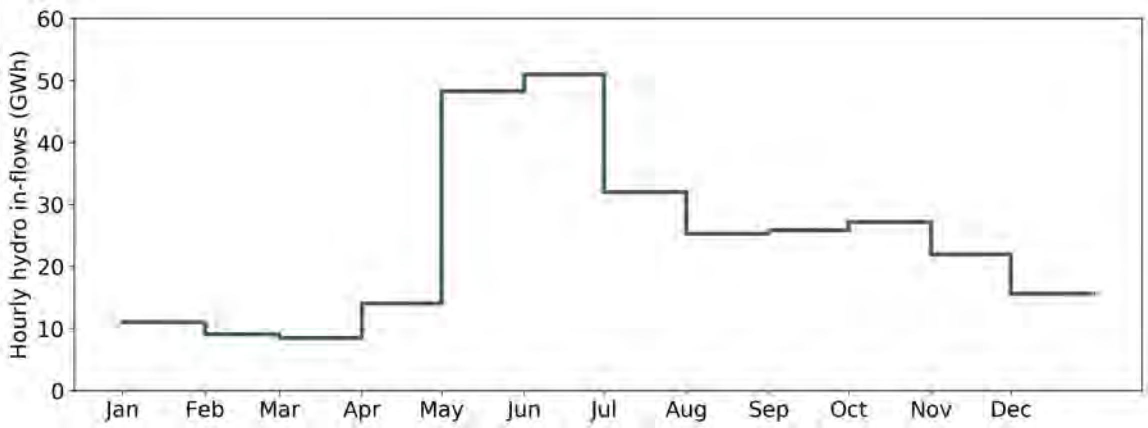

Figure 5: Historical in-flows into hydropower reservoirs in Quebec

3.6 Electricity demand

Hourly electricity demand data is based on 2050 load data for New England and New York (Mai et al. (2018a), Mai et al. (2018b)). This data is based on 2012 weather patterns. We therefore use 2012 data for other weather-dependent variables, including renewable capacity factors, to account for statistical associations between these variables (with the exception of reservoir hydro inflow data in Quebec due to data limitations). For electricity demand, we use the NREL "Reference" scenario from Mai et al. (2018b), which follows the EIA Annual Energy Outlook 2017 Reference case (U.S. Energy Information Administration (2017)). All load data uses NREL's "Moderate" assumption for the efficiency of electrification technologies and NREL's "Base" load flexibility parameters. The total 2050 loads in New England and New York represent annual load growth of 9% and 8% relative to 2016 NREL estimated values respectively. This increase in demand primarily reflects population and economic growth. In section 4.3, we model the impact of large-scale electrification using the NREL "High" electrification scenario (also assuming "Moderate" end use efficiency and "Base" load flexibility) from Mai et al. (2018b).

For Quebec load, we use hourly data for 2012 (Regie de l'energie Quebec (2014)), reflecting a total annual load of 180 TWh, and assume an annual growth rate of 0.4% consistent with projections by Hydro-Quebec Distribution for the next decade Hydro Quebec Distribution (2019) and long-term projections by Williams et al. (2018). The load duration curves for all three regions are displayed in Figure 6.

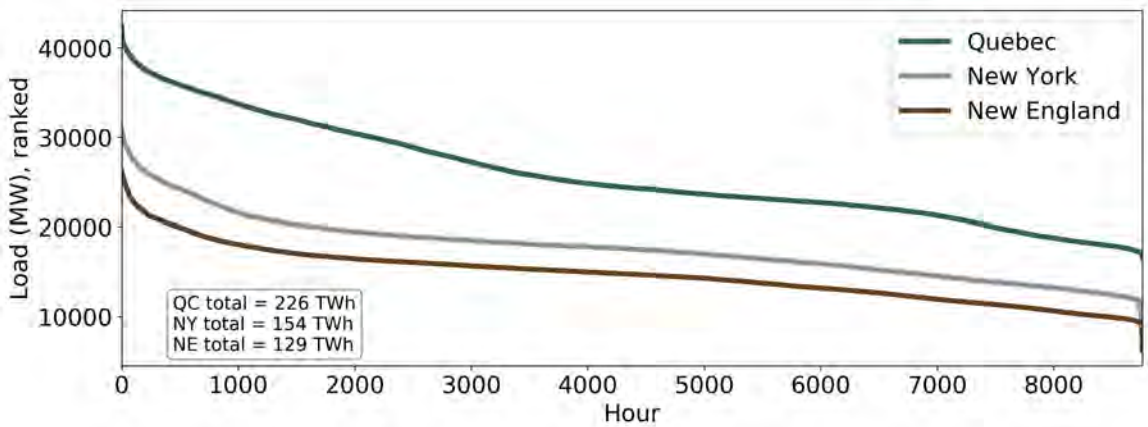

Figure 6: Load duration curve by region in 2050

To represent trade between Quebec and regions not modeled (Ontario and New Brunswick), we further adjust the Quebec load inputted into GenX. For this purpose, we increase the Quebec load by the 2012 hourly net exports from Quebec to Ontario (Independent Electricity System Operator (2019)) and to New Brunswick (Energie NB Power (2019)). The purpose of this adjustment is to account for the demand placed on Quebec's power system that is additional to the demand being represented by our model (the load presented in Figure 6 does not include this adjustment). While a share of Quebec's exports to New Brunswick are for the purposes of wheeling power to New England (Hydro Quebec (2019b)), we do not represent flows from New Brunswick to New England in our model.

3.7 Renewable capacity factors

Hourly capacity factors for onshore and offshore wind for New England and New York are based on the NREL Wind Toolkit dataset of hourly power output based on 2012 meteorology at potential wind turbine site locations (Draxl et al. (2015)). We compile data from all sites corresponding to each region and estimate regional average capacity factors. Onshore wind in Quebec is based on modeled power output using 2012 wind speed data from the NREL's gridded atmospheric WIND Toolkit (National Renewable Energy Laboratory (2019b)) and power curves described in Draxl et al. (2015). The capacity factor represents an average across Quebec with the exception of metropolitan areas (Statistics Canada (2019)) and national parks (Government of Canada (2019)). We estimate solar capacity factors in New England, New York, and Quebec by modeling power output for a representative PV system at a large number of points uniformly spread across each region. We assume PV systems are one-axis east-west tracking with 0-degree tilt based on the most common utility-scale project design (Bolinger, Seel, and Robson (2019)). Insolation data is sourced from the National Solar Radiation Database (Habte, Sengupta, and Lopez (2017)). We use the PV model developed by Brown and O'Sullivan (2019) based on the PVLIB Python toolbox (Stein et al. (2016)). Run of river capacity factors in New England and New York are calculated by dividing monthly 2012 generation from U.S. Energy Information Administration (2013) by capacity from U.S. Energy Information Administration (2019b).

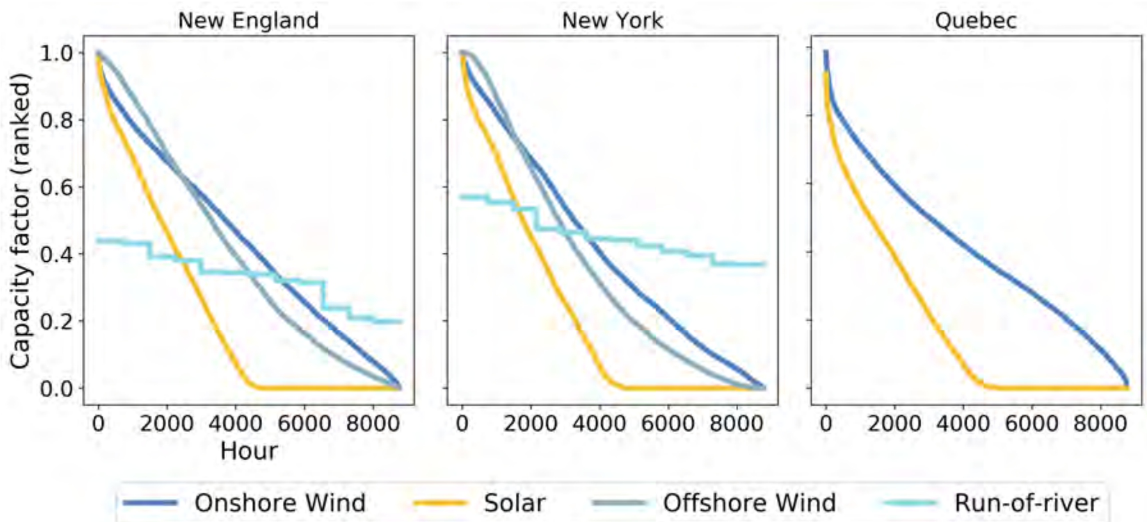

Figure 7: Variable renewable capacity factors by region

3.8 Transmission costs

Transmission expansion costs depend on site-specific factors including presence of existing right-of-ways, the state of the existing network (the need for substation upgrades), and whether the lines are overhead or buried. A selection of three recent projects in the Northeast shows high variability as displayed in Table 9[4]. Champlain Hudson Power Express line, a buried line, is the most expensive of the three. For our discussion on the costs and benefits of new transmission (Section 4.1.3), we assume an investment cost for transmission expansion of $1,129,778/MW (the average between the reported costs of Northern Pass and the New England Clean Energy Connect). We annualize this number and estimate an yearly cost of

[4]Sources for NPT: International Hydropower Association (2018); NECEC: NECEC (2020); CHPE: TDI (2020).

$49 million per GW (Table 10). The values for return on equity, interest rate, and tax rate are sourced from National Renewable Energy Laboratory (2019a).

Table 9: Transmission projects and costs

Line	Cost ($US billion)	MW	Miles	Cost ($/MW-mile)
Northern Pass	1.60	1,090	192	7,645
New England Clean Energy Connect	0.95	1,200	145	5,460
Champlain Hudson Power Express	3.00	1,000	330	9,091

Table 10: Calculation of annual transmission cost (New England)

Cost factor	Value
Investment cost ($/MW)	1,129,778
Return on equity	0.11
Interest rate	0.06
Debt fraction	1.00
Tax rate	0.26
WACC	0.04
Inflation	0.03
WACC (real)	0.02
Capital recovery period	30
Capital recovery factor	0.04
Annual cost ($/GW)	49,326,139

3.9 Scenarios

We design a set of scenarios, described in detail in Table 11, which explore this paper's three overarching questions: how decarbonization alters the optimal technology mix and operation of the power system under study; how transmission expansion between Quebec and neighboring jurisdictions impacts the power system under a given level of decarbonization; and how transmission expansion impacts power system costs. We explore each of these questions separately for New England and New York. The purpose is to show how decarbonization and additional transmission to Quebec will impact each individual jurisdiction (New England and New York respectively).

We explore the first question by modeling the impact of decarbonization in a given jurisdiction assuming that transmission capacity between the respective jurisdiction and Quebec remains at the current level (represented by our Current Transmission scenarios). We run four Current Transmission scenarios, each assuming a given level of decarbonization ranging from 80% to 100%. Each decarbonization scenario denotes a given reduction in CO2 emissions from power generation relative to 1990 levels in the respective jurisdiction. We then explore the impact of transmission expansion in the "New Transmission" scenarios, which assume that transmission between Quebec and the respective jurisdiction is increased by 4 GW. New Transmission scenarios are run for the same range of decarbonization targets to assess how the effects of transmission expansion vary across decarbonization levels.

Table 11: Scenarios descriptions

Analysis Focus	Description	Transmission Capacity (GW) from Quebec to … New England	New York	Decarbonization constraint in … New England	New York
New England	Current Transmission	2.225	2	80% 90% 99% 100%	----90%----
	New Transmission	6.225	2	80% 90% 99% 100%	----90%----
New York	Current Transmission	2.225	2	----90%----	80% 90% 99% 100%
	New Transmission	2.225	6	----90%----	80% 90% 99% 100%

To isolate the impacts of decarbonization and transmission expansion in a one jurisdiction (for example, New England), we keep the model's constraints on CO2 emissions and transmission in the other U.S. jurisdiction (for example, New York) unchanged, as shown in Table 11. For this purpose, we assume that the second jurisdiction decarbonizes its power sector by 90% and maintains its transmission capacity with Quebec at its current level. It is noteworthy that this 90% decarbonization constraint is lower than decarbonization goals expressed by some U.S. states such as the 2040 target for a 100% carbon-free electricity stipulated in New York's Climate Leadership and Community Protection Act or Connecticut's 2040 100% clean electricity goal. The purpose of this assumption is to approximately account for the likely low-carbon characteristic of the future power systems and thus ensure the results are relatively generalizable. Our model's results for fully decarbonized power systems are likely to be less generalizable than those for less ambitious levels of decarbonization due to the possibility that jurisdictions meet 100% CO2 abatement targets using resources not represented in our model (such as negative emission technologies or new long-term storage technologies).

The scenarios described in Table 11 are modeled for a Base Case, which reflects our central assumptions described in this section. Additionally, we run these scenarios for a number of sensitivity cases discussed in Section 4.3.

4 Results

We first present our New England analysis where we discuss the optimal technology mix and operation of the New England power system under deep decarbonization (Section 4.1.1). Next, we present results on the power system impact of new transmission between New England and Quebec (Section 4.1.2), comparing the New Transmission decarbonization scenarios for New England to the respective Current Transmission scenarios. We then show how power system costs in New England and Quebec change as a result of new transmission (Section 4.1.3). The same questions are explored for New York in Section 4.2. Finally, in Section 4.3, we discuss the sensitivity of our results to relevant underlying assumptions.

4.1 New England analysis

4.1.1 Effects of New England decarbonization with current transmission

The optimal technology mix for New England's power system across different levels of decarbonization is shown in Figure 8[5]. For 80% decarbonization, the power system portfolio includes existing assets - Open Cycle Gas Turbines (OCGT), Combined Cycle Gas Turbines (CCGT), nuclear, and hydropower - as well as new resources (solar, wind, and a small amount of new CCGT). Offshore wind is also present in all scenarios because the model is constrained to meet existing offshore targets in New England. Existing gas plants play a balancing role in 2050 and are dispatched in periods of high net demand (when demand is relatively high compared to variable renewable output from wind, solar, and run-of-river hydro plants). Their average capacity factor is 0.14. New gas capacity is run more frequently with a capacity factor of 0.48. Nuclear plants run almost uninterrupted but are ramped down during periods of high renewable output, with an overall capacity factor of 0.96 (our model does not factor in refueling; in reality nuclear's capacity factor will be somewhat lower).

If New England were to decarbonize further than 80%, new and existing gas capacity and energy becomes displaced by wind, solar, and CCGT CCS, which plays the role of providing energy during hours of high net demand in the near-full decarbonization of 99%. Li-ion batteries play an intra-daily balancing role in the 99% decarbonization scenario and to a larger extent under a 100% decarbonization target. Full decarbonization (100% scenario) requires a high renewable capacity approach to ensure demand is met even during periods of low availability of solar, wind, and run-of-river hydro in New England. In our model,

[5]ROR refers to run-of-river hydropower; Imports and exports refer to power flows from and to Quebec

such periods occur during the summer (particularly July and August), when wind capacity factors are relatively low. Full decarbonization precludes CCS (this is because we assume a less-than complete CCS carbon capture rate of 90%), requiring demand to be met by variable renewable energy, batteries, and nuclear. However, nuclear generation decreases in the 100% scenario relative to less stringent decarbonization scenarios because the greater wind and solar capacities in this scenario decrease the model's marginal power costs, leading to fewer hours during which nuclear can be economically dispatched while respecting operational constraints (described in Section 3). This results in a nuclear capacity factor of 0.21.

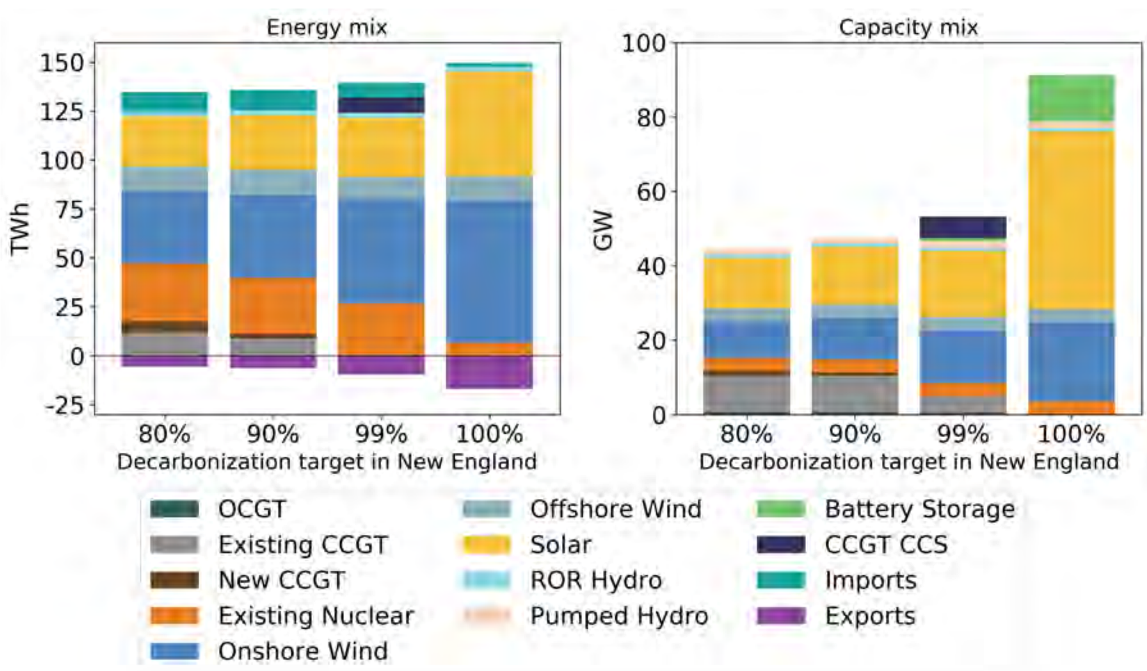

Figure 8: Technology portfolio in New England by CO2 reduction scenario

CO2 emissions in New England are reduced by 85% in our 80% scenario. According to our model, it is cheaper for New England to achieve a deeper level of decarbonization than required by the target (the implied CO2 price in our model is zero in this scenario). Deeper emission reductions, however, come at a cost. For example, our 90% decarbonization scenario results in a CO2 price of $42/ton-CO2.

Estimated imports from Quebec under deep decarbonization are lower than current levels (Figure 10). In 2018, New England imported approximately 13 TWh from Quebec through the Phase 2 and Highgate transmission lines (ISO-NE (2019a). In the 80% decarbonization scenario, imports are 10 TWh. This occurs because, as New England decarbonizes, imports from Quebec compete with zero-marginal-cost wind and solar energy. In a deeply decarbonized New England, wind and solar output decrease the model's estimated electricity marginal cost in New England below the estimated electricity marginal cost in Quebec (driven by the water value of reservoir hydro) during a considerable number of hours out of the year, thus disincentivizing imports. The share of imports from Quebec in the energy mix further decreases as the emission target becomes more stringent (Figure 8 and 10) as wind and solar generation in New England rises. Concurrently, exports from New England to Quebec increase with decarbonization, as it becomes economical for Quebec to import excess low-cost renewable energy from New England. This result indicates that two-way trading of electricity is the optimal use of the transmission infrastructure in a low-carbon future. We estimate that the power system cost across New England and Quebec is lower with two-way flows by 5-6% than if we constrain our model to allow only north-to-south power flows, depending on the decarbonization scenario, equivalent to cost saving of $1-2/MWh.

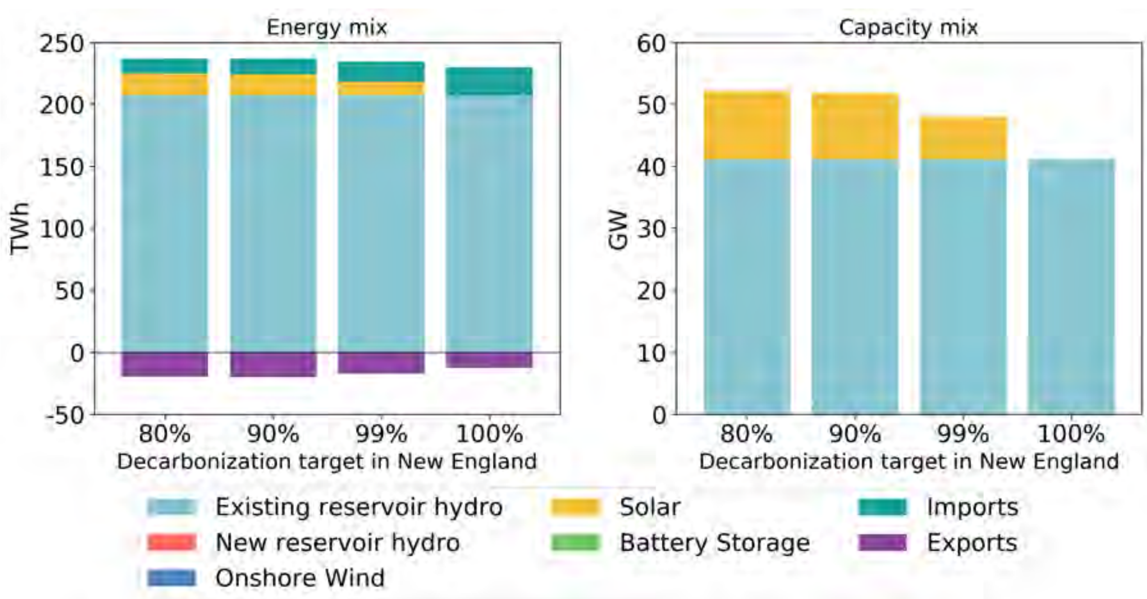

Figure 9: Technology portfolio in Quebec by CO2 reduction scenario

In Quebec, the optimal capacity and energy mixes (Figure 9) includes existing reservoir hydro, as well as new solar. Imports from the U.S. are also part of the optimal mix, with Quebec importing approximately 12 TWh from New England and New York in the Current Transmission-80% New England scenario. In comparison, in 2018, Quebec imported no energy from New England and approximately 0.9 GWh from New York (New York ISO (2019), ISO-NE (2019a)). As New England's decarbonization target increases, solar in Quebec decreases both in terms of capacity and generation as it is outcompeted by renewable resources with better capacity factors in New England. The amount of hydro generation is the same across decarbonization scenarios.

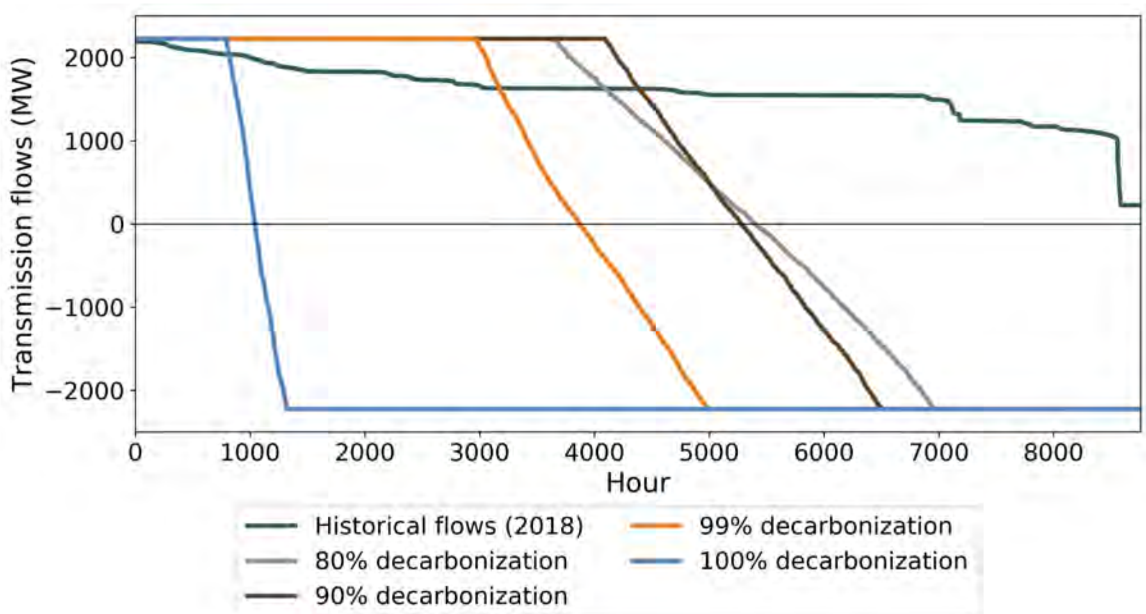

Figure 10: Power flows between New England and Quebec by CO2 reduction target in New England (positive values denote north-to-south flows)

In the set of New England scenarios being discussed in this section, the New York power system is constrained to decarbonize by at least 90%. As a result, the modeled New York energy mix is comprised of 76% renewable energy, the rest roughly equally split between new CCGT plants and existing nuclear plants. The optimal mix and operation of the New York power system are virtually the same across decarbonization targets in New England.

The utilization of the transmission capacity between New England and Quebec changes with deep decarbonization. While transmission lines our currently used exclusively to send power from Quebec to New England, in 2050 they are used to send power in both directions in our model. Figure 10 displays the power flows through the transmission lines linking New England and Quebec. A positive value indicates power flowing from Quebec to New England and vice versa.

4.1.2 Effects of new transmission on the New England and Quebec power systems

In New England, new transmission raises wind and solar capacity and generation and lowers gas generation and capacity relative to the Current Transmission scenarios (Figures 11). New transmission allows New England to export more energy during periods of high renewable output and import more energy in other periods when gas plants are otherwise dispatched. This effectively enables New England to replace gas with wind and solar (and in some scenarios with nuclear). This effect applies to both existing and new gas plants. New gas plants are no longer part of the optimal technology mix in any of our scenarios. As gas generation declines, CO_2 emissions fall by 5 Mt and 2 Mt in the 80% and 90% decarbonization scenario respectively. In the 99% decarbonization scenario, new transmission drastically reduces the need for CCS. Another effect of new transmission is an increase in generation from existing nuclear plants. As additional transmission enables New England to export more excess renewable energy, it alleviates the economic pressure on nuclear plants to ramp down in periods of high renewable output.

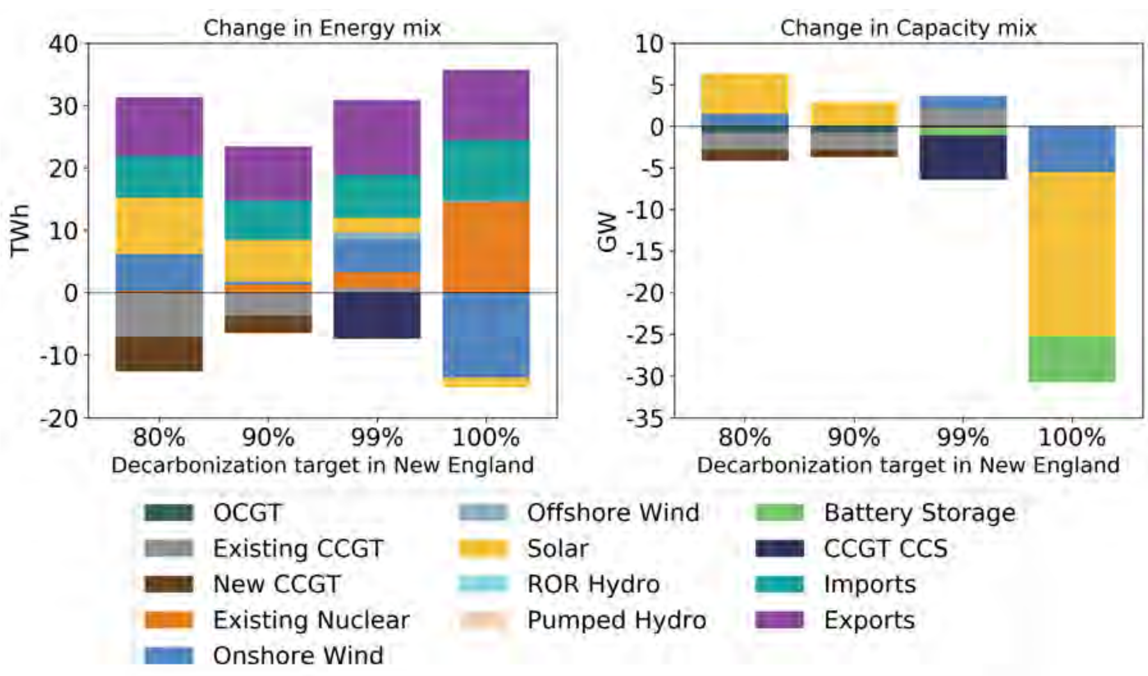

Figure 11: Effects of new transmission (4 GW) on technology portfolio in New England relative to current transmission

In the 100% decarbonization scenario, transmission expansion reduces renewable generation and capacity (Figure 11) in New England. By making additional imports available during hours of relatively low intermittent renewable availability, new transmission reduces the need for rarely used wind and solar capacity. This mitigates renewable curtailments by 93%, or 44 TWh (Figure 14).

Trading between New England and Quebec increases in both directions as a result of transmission expansion (Figure 11). In most scenarios, net imports decrease because additional transmission allows Quebec to import more net energy from New England, where wind and solar have greater capacity factors relative to Quebec. Renewable generation and capacity in Quebec falls as a result (Figure 12).

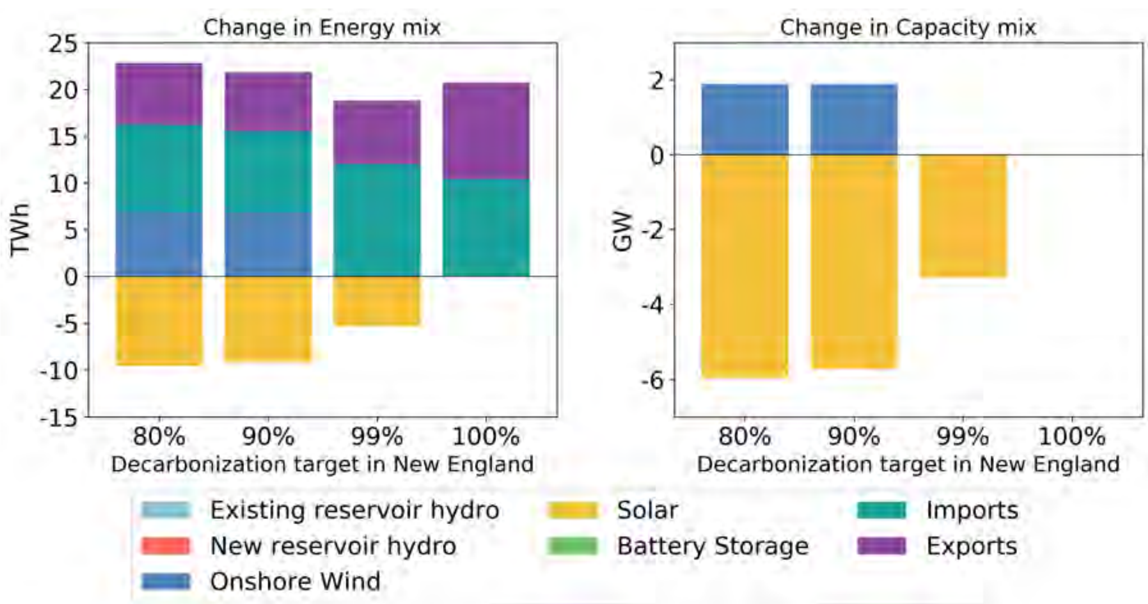

Figure 12: Effects of new transmission (4 GW) on technology portfolio in Quebec relative to current transmission

The overall effects across New England and Quebec are displayed in Figure 13. System-wide renewable generation goes up while gas generation goes down (with the exception of the 100% decarbonization scenario, as discussed above).

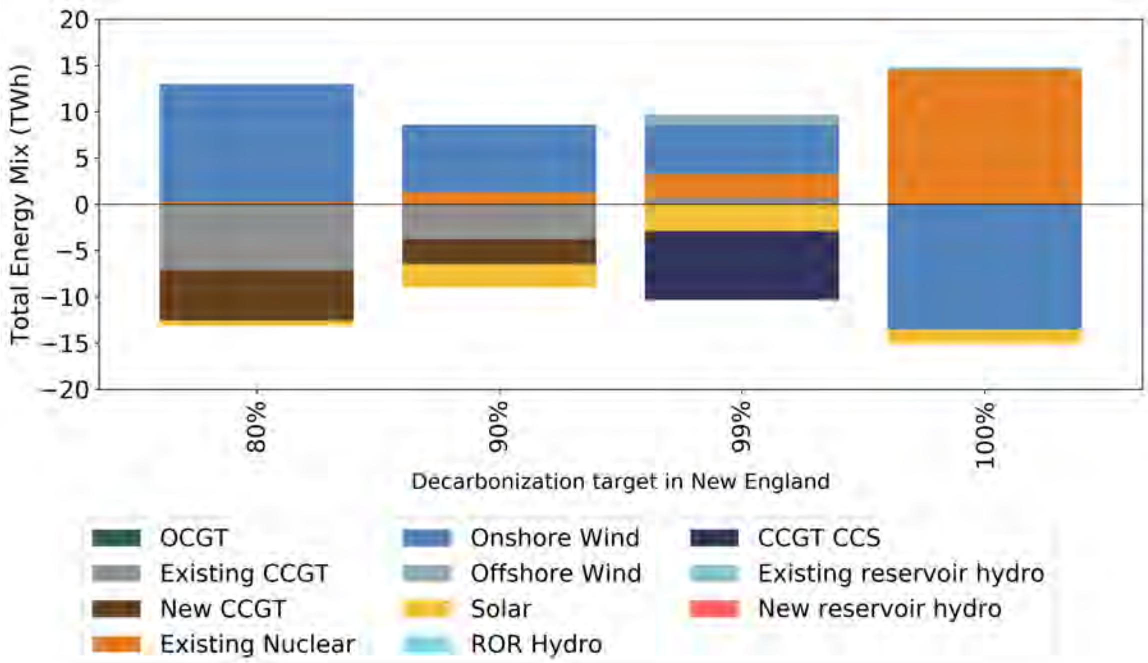

Figure 13: Effects of new transmission (4 GW) on technology portfolio in New England and Quebec relative to current transmission

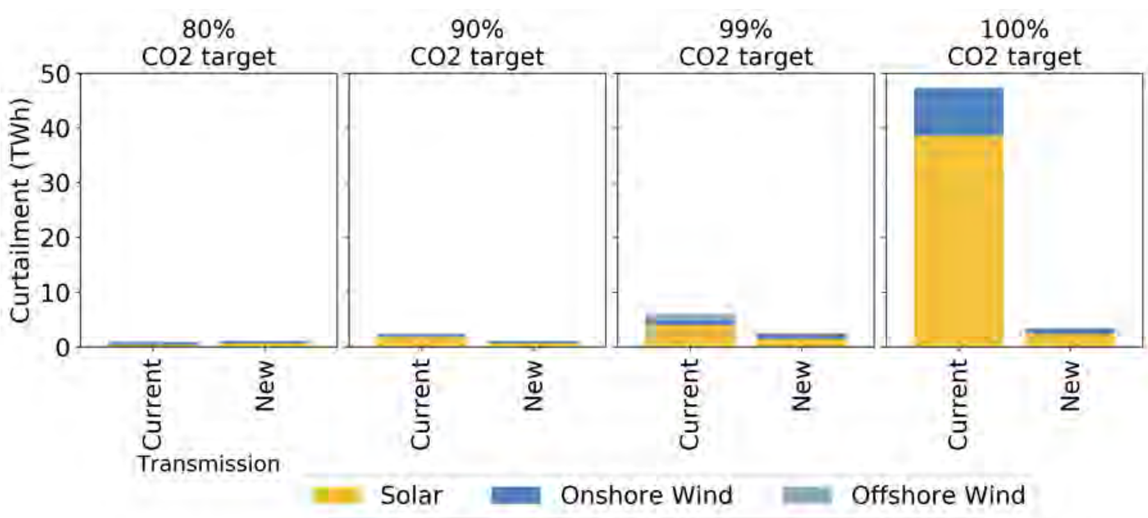

Figure 14: Curtailment of renewable energy in New England by scenario

Notably, new transmission does not result in additional hydro investments (Figure 12). Total hydro generation from existing reservoir hydro also stays the same. However, new transmission alters the way in which the existing reservoir hydro is operated. In the New Transmission scenarios, the timing of existing reservoir hydro operation becomes more complementary to the New England power system and the variability of wind and solar in New England, relative to the Current Transmission scenarios.

Figure 15 illustrates how transmission expansion allows reservoir hydro to provide an additional daily balancing service. The capacity factor of reservoir hydro (actual output relative to power capacity) decreases in the early morning and midday hours and increases during the evening peak in the New Transmission scenario relative to Current Transmission. In the 100% decarbonization scenario, utilization changes by around 10%, equal to approximately 2 GW of power output.

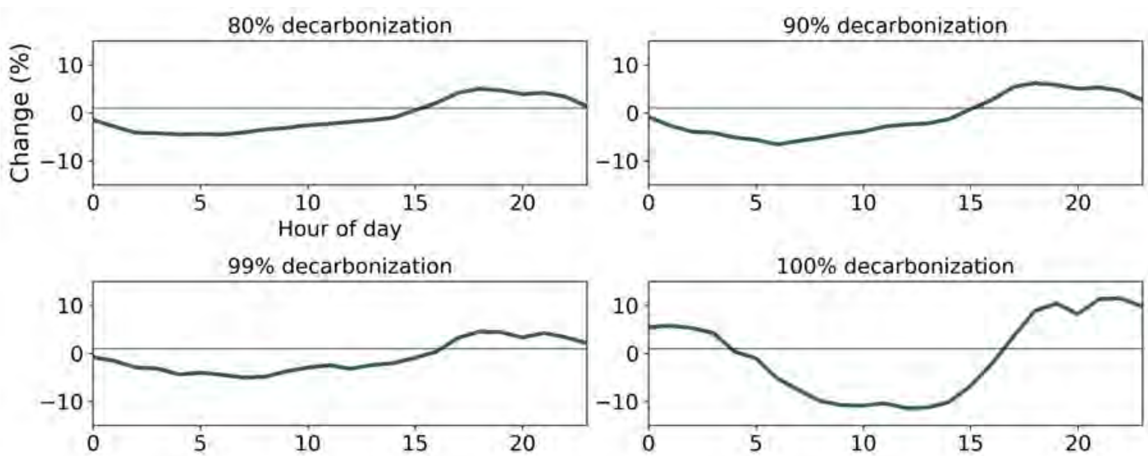

Figure 15: Intra-daily changes in reservoir hydro capacity factor resulting from 4 GW of new New England-Quebec transmission relative to current transmission (average day in 2050)

The operation of the reservoir also changes seasonally. Figure 16 illustrates the change from the Current Transmission to the New Transmission scenarios in average hourly capacity factor across the months of the year. New transmission causes reservoir hydro output to shift toward the summer, raising it by about 10% in August in the 100% decarbonization scenario (equivalent to 2 GW of power output), when New England net demand is relatively high (primarily due to low wind output), thus providing a seasonal balancing service. This is also illustrated in Figure 17, which shows how the state of charge of the reservoir (amount of energy stored relative to the total reservoir storage capacity) changes from the Current Transmission scenario to the New Transmission scenario. New transmission leads the reservoir to store about 2-3 TWh of additional water in the spring. This is followed by a greater discharge from the reservoir in the summer (reflective of greater hydro production and exports to New England). In the fall, the reservoir level is lower than in the Current

Transmission scenario by around 1 TWh (less in the 100% decarbonization scenario). Toward the end of the year, the reservoir receives additional charging (relative to Current Transmission), which is due to the greater amount of net imports from New England (illustrated in Figure 19), partially driven by stronger wind output.

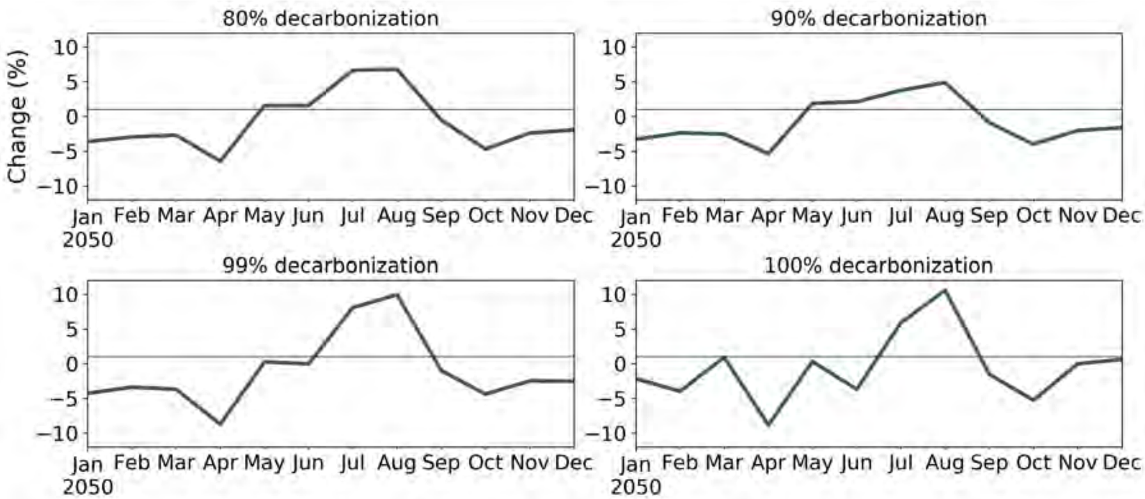

Figure 16: Seasonal changes in reservoir hydro capacity factor resulting from 4 GW of new New England-Quebec transmission relative to current transmission

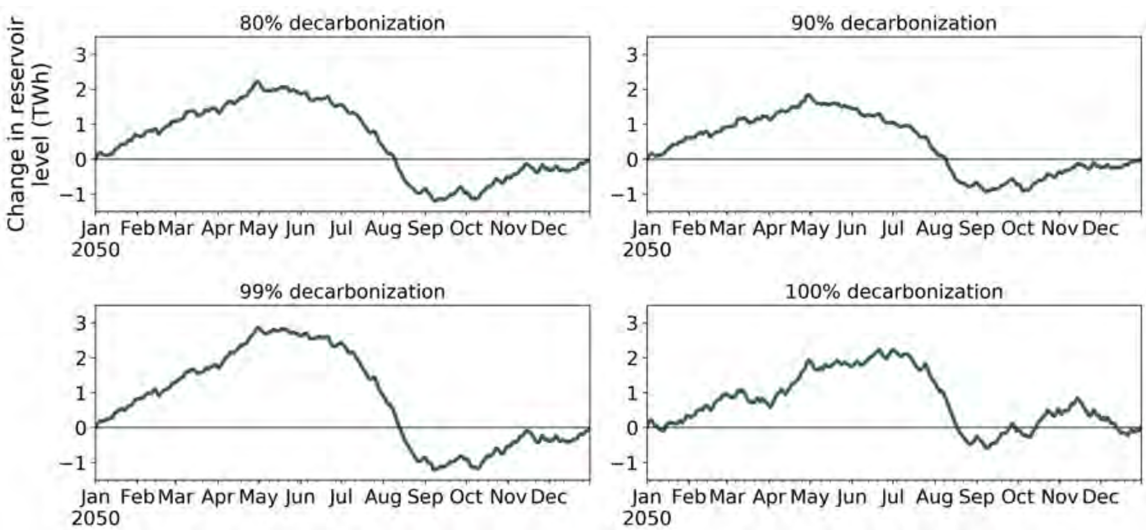

Figure 17: Changes in reservoir hydro storage in Quebec resulting from 4 GW of new transmission relative to current transmission

The additional balancing services enabled by transmission expansion are also reflected in the transmission flows between Quebec and New England. Figure 18 displays the daily transmission flow averaged across the year (positive values reflect flows from Quebec to New England and vice versa). In the New Transmission scenario, exports to Quebec increase in the middle of the day relative to Current Transmission, reflecting high solar output and consequent low marginal cost of electricity in New England. Imports from Quebec rise during the evening peak hours relative to Current Transmission. Figure 19 illustrates the longer-term balancing effects of increased trade with Quebec. The direction of electricity trading shifts both weekly - reflecting balancing at a synoptic (multi-daily) scale - and seasonally, reflecting relatively low New England renewable output in the summer and relatively high output in the spring.

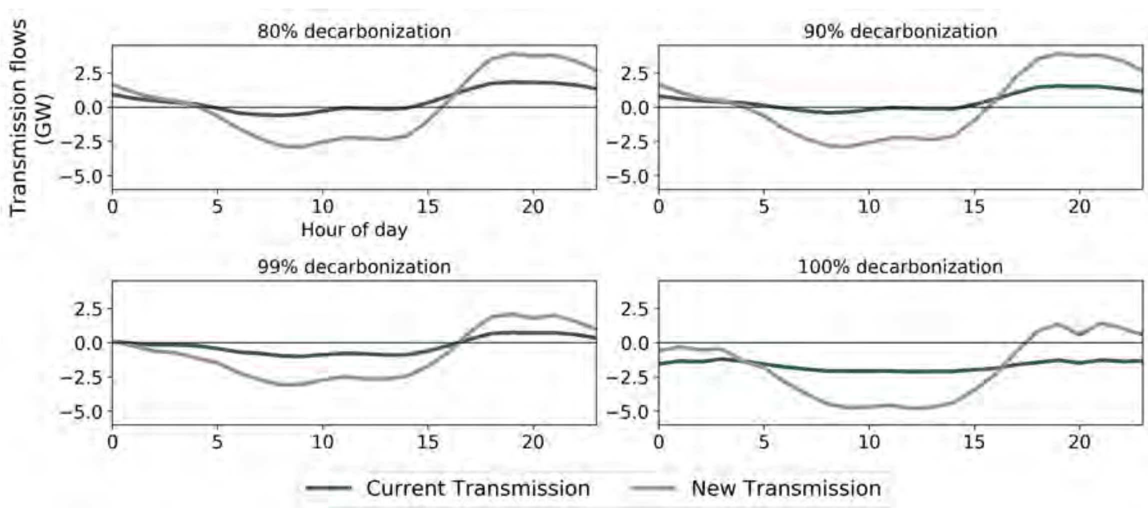

Figure 18: Intra-daily transmission flows between New England and Quebec for an average day in 2050 (positive values denote north-to-south flows)

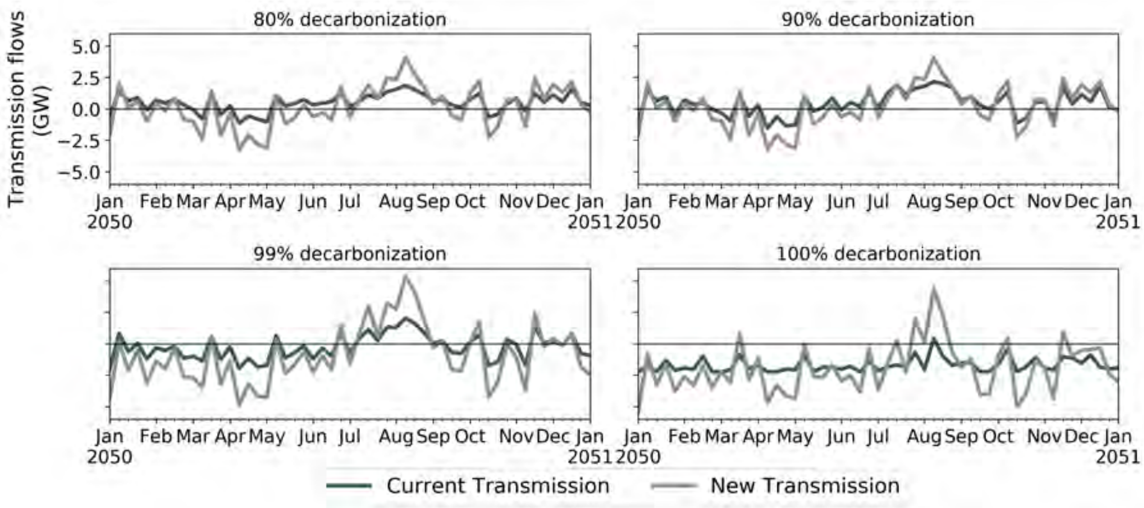

Figure 19: Hourly transmission flows between New England and Quebec averaged for each week in 2050 (positive values denote north-to-south flows)

We further illustrate the daily and synoptic balancing effects of transmission expansion in Figure 20[6]. Here, we focus on the 90% decarbonization scenario and display the first two weeks of October, which are illustrative of the challenges of deep decarbonization. In the first week of October, a multi-day period of low renewable output (relative to demand) causes gas plants to become dispatched in the Current Transmission scenario. In the second week of October, a period of high renewable output leads to curtailed renewable generation. As excess renewable generation drives down the marginal cost of energy, nuclear plants also ramp down.

However, in the New Transmission scenario, imports from Quebec meet a larger portion of demand during the periods of scarcity in early October. This alleviates the need for gas generation. The additional transmission also causes greater exports during the hours of high renewable output, mitigating the curtailment of variable renewables, and reducing the number of nuclear plant ramp-downs.

[6]"Load before DR" and "Load after DR" denote the effect of assumed demand response capability on demand; "Curtailment" relates to solar, onshore wind and offshore wind; "Storage Charging" refers to charging of batteries and pumped hydro.

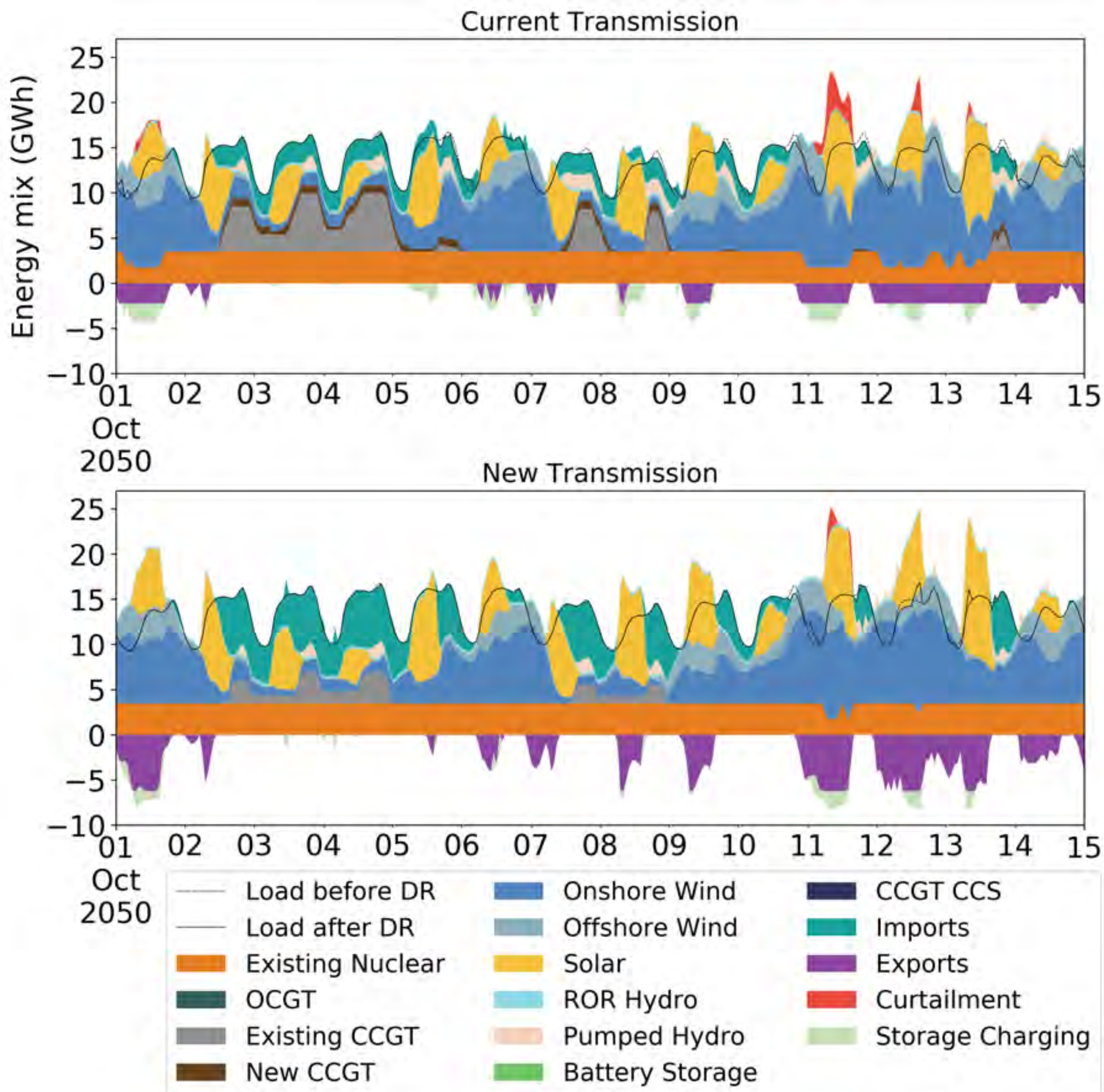

Figure 20: Hourly operation of the New England power system by transmission scenario (90% decarbonization)

4.1.3 Economic value of new transmission between New England and Quebec

The economic effect of transmission expansion varies greatly by the level of decarbonization. Figure 21 displays average power system costs across New England and Quebec with and without new transmission, which captures the cost of: building and operating power generating assets (including technologies for energy storage and demand response), building new transmission, and non-served energy. With a decarbonization target up to 90%, the economic impact of new transmission is approximately neutral. We estimate very modest savings of

0.2 and 0.3 $/MWh in the New Transmission scenarios relative to Current Transmission for 80% and 90% decarbonization respectively. Transmission expansion results in relatively significant savings if New England decarbonizes its power sector by 99% or 100%, equal to 3 and 7 $/MWh respectively (equivalent to total savings of $913 and $2,387 million/year, or reduction in power system costs of 13% and 24%).

The effects of transmission expansion on power system costs are displayed in further detail in the left panel of Figure 21. Under 80% and 90% decarbonization, new transmission results in lower variable costs in New England related to the decrease in gas generation discussed earlier, while leading to higher fixed costs in New England related to the additional investment in renewable capacity. Under 99% decarbonization, savings come from lower fixed costs in New England largely related to the decrease in gas CCS investment (Figure 11). Savings in this scenario also come from reduced variable costs related to gas CCS and fixed costs in Quebec associated with the lower amount of solar investment (Figure 12). Under 100% decarbonization, new transmission leads to a larger reduction in New England fixed costs associated with reduced wind, solar, and battery capacity. Variable costs are somewhat higher due to the previously discussed increase in generation from existing nuclear plants resulting from transmission expansion.

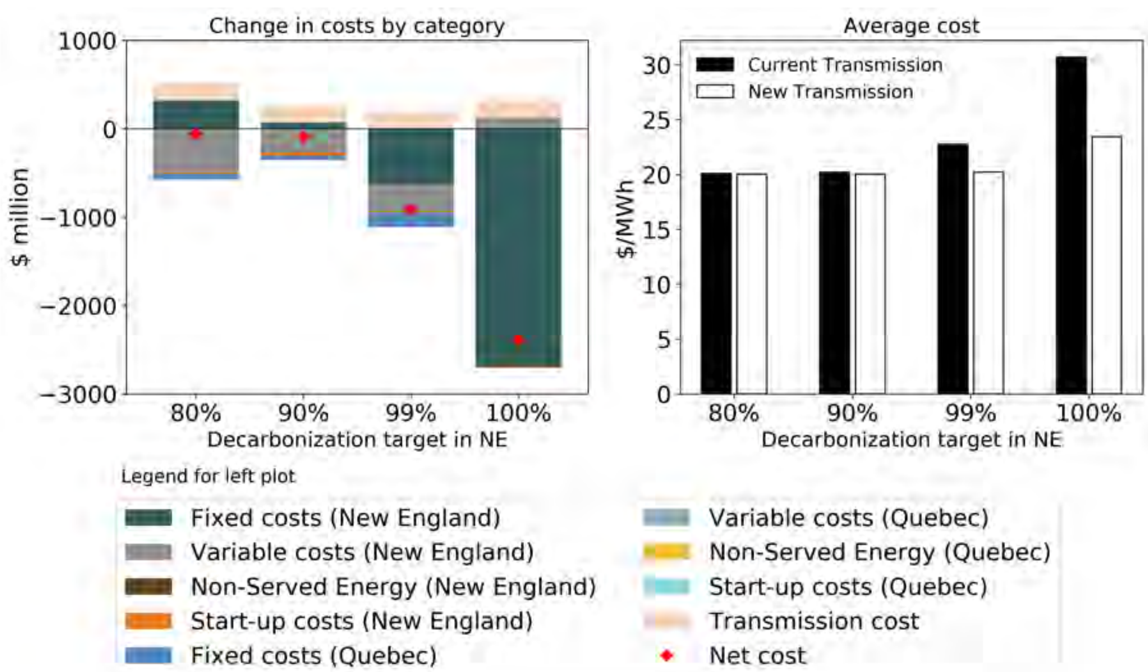

Figure 21: Power system costs in New England and Quebec and effects of new transmission (4 GW)

4.2 New York Analysis

In this section, we present our results on the impacts of deep decarbonization in New York and the effects of transmission expansion between New York and Quebec. Many of the findings are consistent with our New England analysis, due to the similarity between the power systems of these regions. Therefore, we focus on the main findings.

4.2.1 Effects of New York decarbonization with current transmission

The optimal low-carbon technology portfolio in New York is comprised mainly of variable renewable energy, new CCGT plants, and existing nuclear (Figure 22). New CCGT plants play a relatively significant role in New York, in comparison to New England. This results in part from our projection that by 2050, New York will have roughly half as much incumbent gas capacity as New England, requiring more investment in new capacity. Gas plants with CCS become part of the optimal mix in the 99% emission reduction scenario. Full 100% decarbonization results in a significantly greater build-out of variable renewable capacity, a large portion of which is curtailed during periods of excess production. In the scenarios presented in this section, the optimal energy mix in Quebec is similar to the one modeled in our New England analysis (Figure 9, comprising of existing reservoir hydro and new solar capacity that ranges depending on the level of decarbonization in New York).

Deep decarbonization causes New York to become an exporter of energy to Quebec during a portion of the year. The deeper the decarbonization target, the greater the amount of exported energy from New York. As discussed in our New England analysis (Section 4.1.1), this increase in exports is driven by the increase in zero-marginal-cost renewable energy in New York.

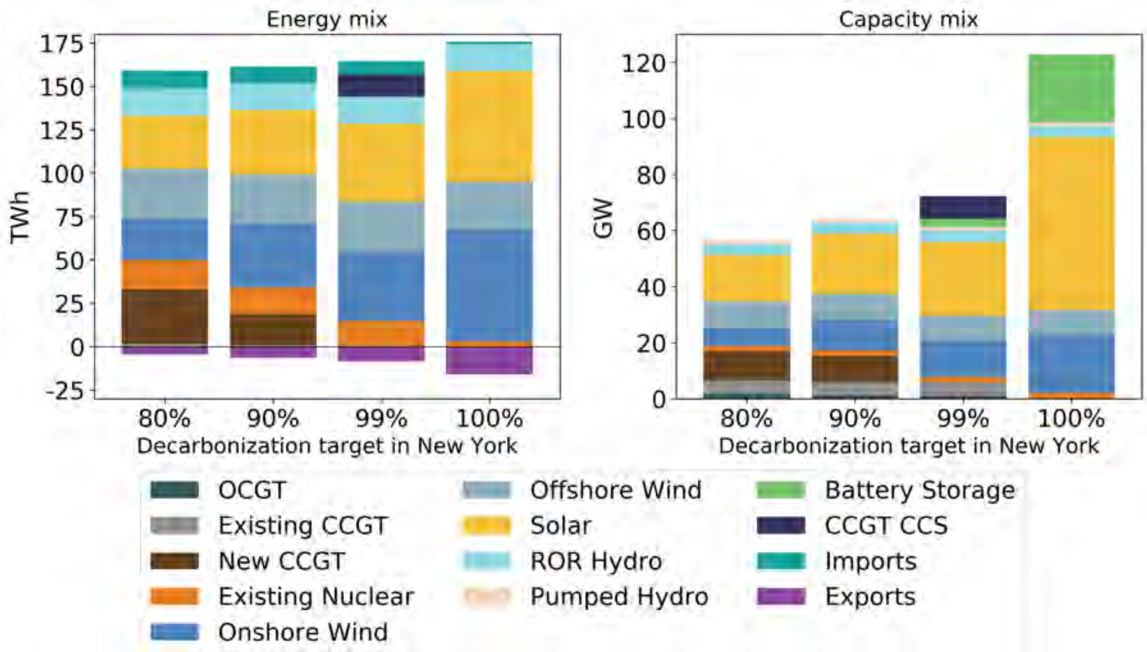

Figure 22: Technology portfolio in New York by CO2 reduction scenario

4.2.2 Effects of new transmission on the New York and Quebec power systems

Transmission expansion between New York and Quebec reduces generation from new gas plants (CCGT with and without CCS, depending on the CO2 abatement goal), increases renewable generation, and increases nuclear generation under 90% decarbonization and beyond (Figure 23). As a result, CO2 emissions in New York decline by 6 Mt and 1 Mt in the 80% and 90% decarbonization scenarios respectively. Additional transmission also reduces renewable generation in Quebec, which is replaced by renewable generation in New York. Overall, renewable generation across New York and Quebec increases and gas generation decreases across decarbonization scenarios (with the exception of the 100% decarbonization scenario). It is also noteworthy that new transmission does not lead to new reservoir hydro investments or more hydro generation in Quebec. Instead it allows the existing hydropower to be operated in a way more complementary with renewable plants in New York. Specifically, in the New Transmission scenario, Quebec's reservoir hydropower is able to provide greater balancing services to New York at a both daily (Figure 24) and seasonal (Figure 25) scale. The results of our New York analysis are broadly consistent with our New England analysis, where we discuss the reasons behind the modeled effects in more detail (Section 4.1).

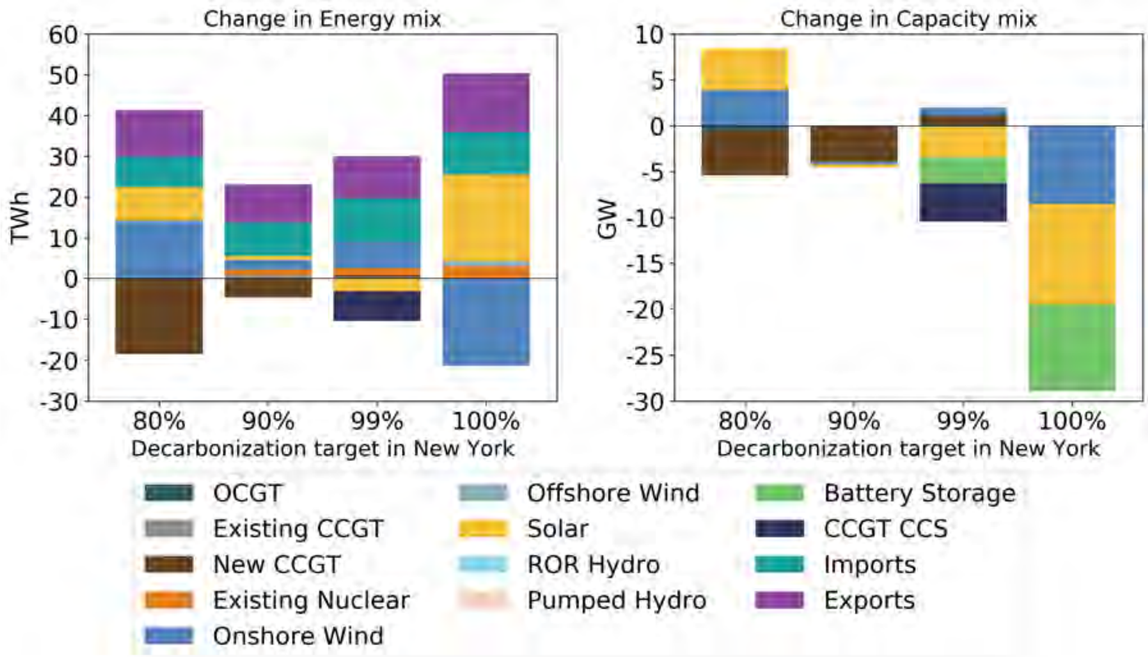

Figure 23: Effects of new transmission (4 GW) on technology portfolio in New York relative to current transmission

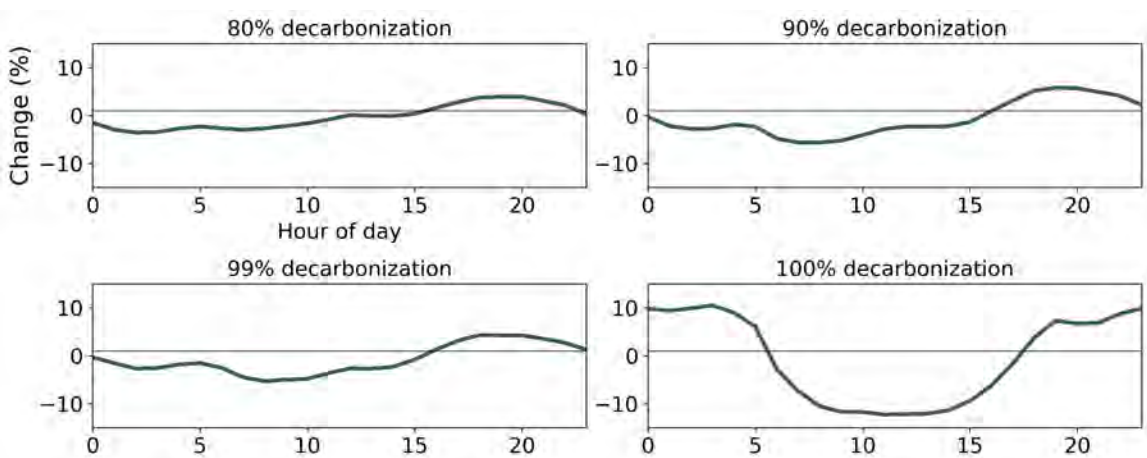

Figure 24: Intra-daily changes in reservoir hydro capacity factor resulting from 4 GW of new New York-Quebec transmission relative to current transmission (average day in 2050)

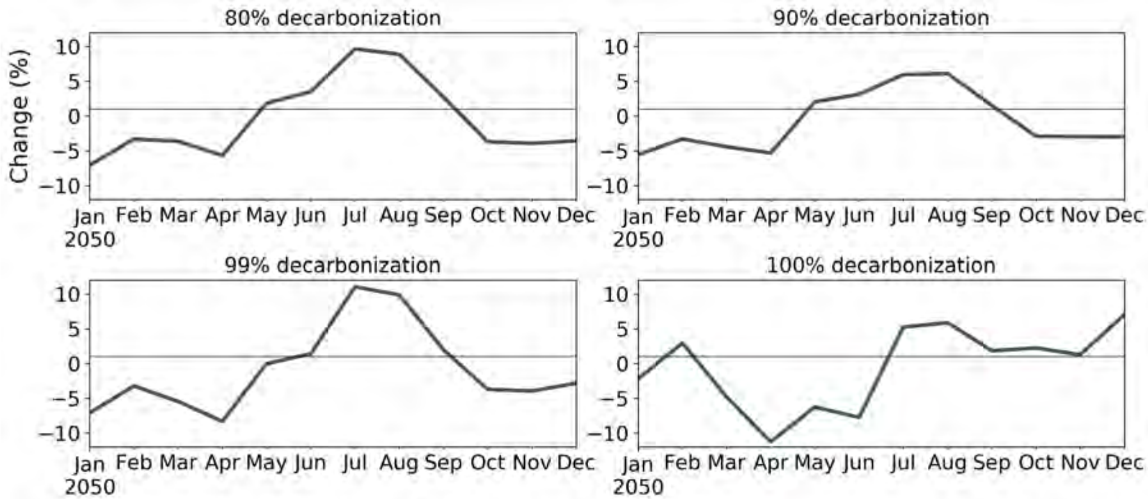

Figure 25: Seasonal changes in reservoir hydro capacity factor resulting from 4 GW of new New York-Quebec transmission relative to current transmission

4.2.3 Economic value of new transmission between New York and Quebec

Transmission expansion between New York and Quebec results in overall power system savings (after accounting for the costs of transmission). These net benefits are particularly significant if New York achieves near-full or full decarbonization (Figure 26). The savings are primarily the result of avoided fixed and variable costs for building and operating CCGT plants without CCS (in the 80% and 90% decarbonization scenarios) and CCGT plants with CCS (in the 99% decarbonization scenario), and the result of avoided fixed costs for building variable renewable energy and battery capacity in the 100% decarbonization scenario. This result is also consistent across New England and New York.

Net cost savings across New York and Quebec resulting from new transmission equal \$190, \$330, \$1121, and \$3,057 million per year. Average power system cost savings across the two regions are estimated at \$0.5, \$0.9, \$3, and \$8 per MWh of electricity. This is equivalent to reductions in power system costs of 3%, 4%, 13%, and 23% respectively.

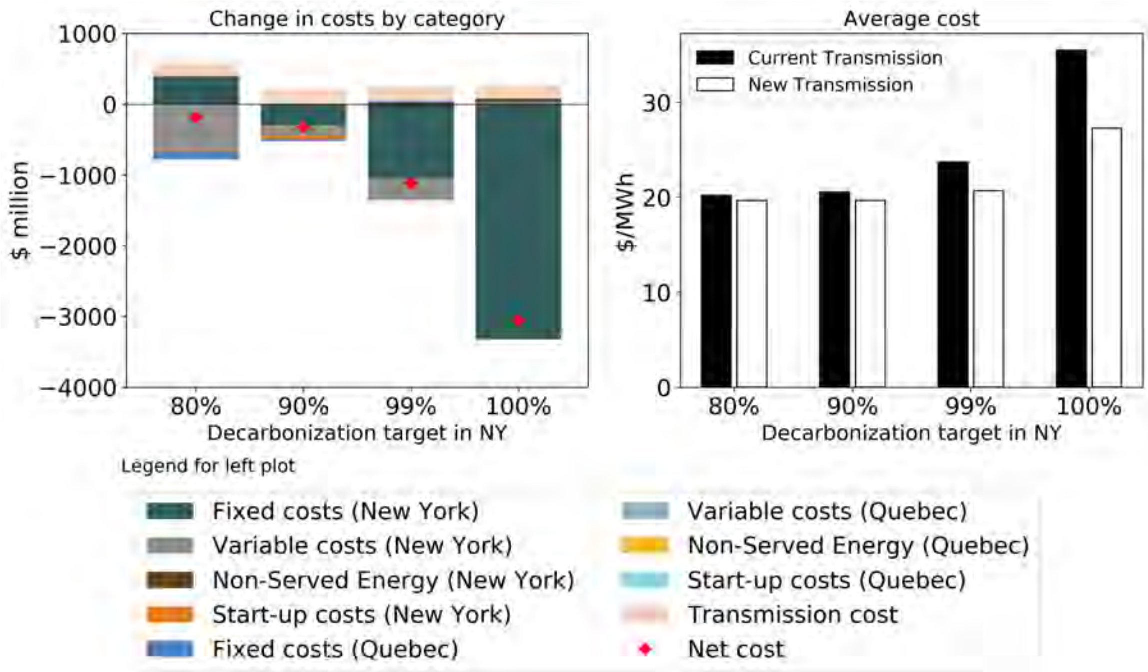

Figure 26: Power system costs in New York and Quebec and effects of new transmission (4 GW)

4.3 Sensitivity Analysis

We run the scenarios featured in Table 11 for a set of alternative cases that test the sensitivity of our results to assumptions other than the Base Case inputs we presented in Section 3.

4.3.1 Renewable-only decarbonization

We model a case where states pursue a renewable-only approach to decarbonization focused on variable renewable energy, which we refer to as "VRE Only". Nuclear plants and CCS are prevented from participating in the technology mix. In the absence of these firm resources, the optimal technology mix in New England features a significant build-out of variable renewable energy capacity, and greater investments in battery storage for 99% decarbonization and beyond (Figure 27). Under less ambitious CO2 targets, New England relies more heavily on new CCGT investments. As a result, annual CO2 emissions are 2 Mt higher in the 80% decarbonization scenario with current transmission relative to our Base Case. Expanding transmission capacity to Quebec decreases the amount of variable renewable capacity needed for deep decarbonization, and reduces the reliance on new CCGT plants.

In the absence of nuclear or CCS, transmission expansion results in more significant power system savings across New England and Quebec (Figure 29). The additional savings stem primarily from lower expenses on variable renewable energy capacity as well as avoidance of non-served energy in the 100% decarbonization scenario. The total power system cost savings across New England and Quebec in the New Transmission scenario relative to Current Transmission equal \$7, and \$10 per MWh in the 99%, and 100% decarbonization scenarios respectively. This is equivalent to relative savings of 26% and 28% respectively.

4.3.2 High renewable energy costs

We model a case in which the investment cost of variable renewable energy (including solar, onshore wind, and offshore wind) is 50% greater than assumed in our Base Case. This assumption results in a somewhat greater reliance on gas relative to our Base Case (see Figure 28 where this case is denoted as "High VRE costs").

In contrast to our Base Case, the optimal mix in Quebec includes between 1 and 2 GW of new hydropower in the 80%, 90%, and 99% decarbonization scenarios. This capacity is further expanded by 0.4-1.5 GW with the addition of new transmission. However, new hydro is not built in the 100% decarbonization scenarios, demonstrating how optimal technology mixes are not monotonic across decarbonization levels (Sepulveda et al. (2018). We also note that raising renewable costs by 40% rather than 50% does not result in new hydro investments in any scenario.

The addition of new transmission has similar effects as in our Base Case across decarbonization scenarios including: a decrease in net imports, a reduction of gas generation; and an increase in New England variable renewable energy generation and capacity (except in the 100% scenario). Unlike our Base Case, new CCGT gas plants play a role in the energy mix in the New Transmission scenarios as well.

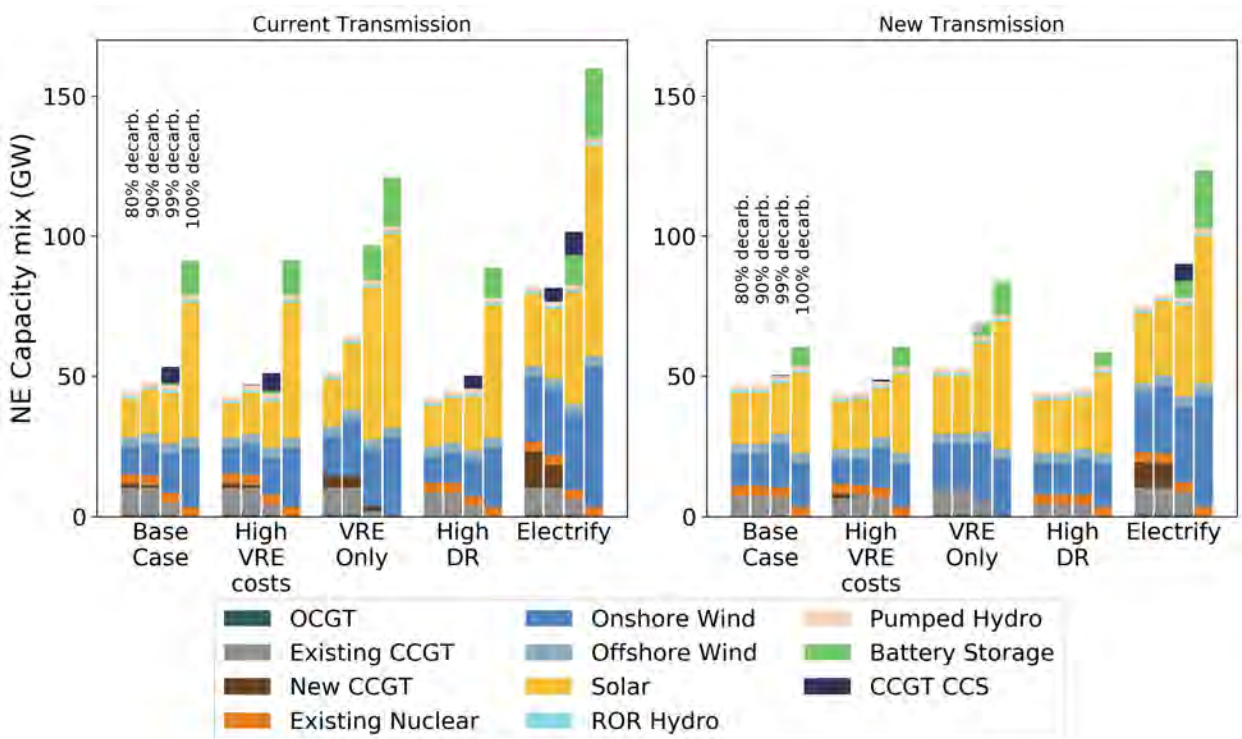

Figure 27: Capacity mix in New England in 2050 by scenario and case

The total power system cost savings across New England and Quebec in the New Transmission scenario relative to Current Transmission equal \$3 and \$9 per MWh in the 99%, and 100% decarbonization scenarios respectively. This is equivalent to relative savings of 11% and 25% respectively. The net economic value of new transmission is greater than in our Base Case (Figure 29) in the 100% decarbonization scenario. The greater value stems from greater savings from investments in variable renewable energy.

4.3.3 Greater capability for demand response

As discussed in Section 3, our Base Case results assume the availability of a demand response resource that can shift 5% of hourly total load within a six-hour window. Here we model a ”High DR” case, in which the demand response resource can shift 20% of hourly load.

In the Current Transmission scenarios, greater demand response results in a lesser need for gas generation relative to our Base Case, resulting in no new CCGT investments (Figure 27).

New transmission provides a comparable net value to the power system as in the Base Case scenarios (Figure 29). This suggests that the daily balancing service provided by demand response does not detract from the value of Quebec hydro, which provides flexibility at not only daily but also synoptic and seasonal scales. The total power system cost savings across New England and Quebec in the New Transmission scenario relative to Current Transmission equal \$2, and \$7 per MWh in the 99%, and 100% decarbonization scenarios respectively. This is equivalent to relative savings of 11% and 26% respectively.

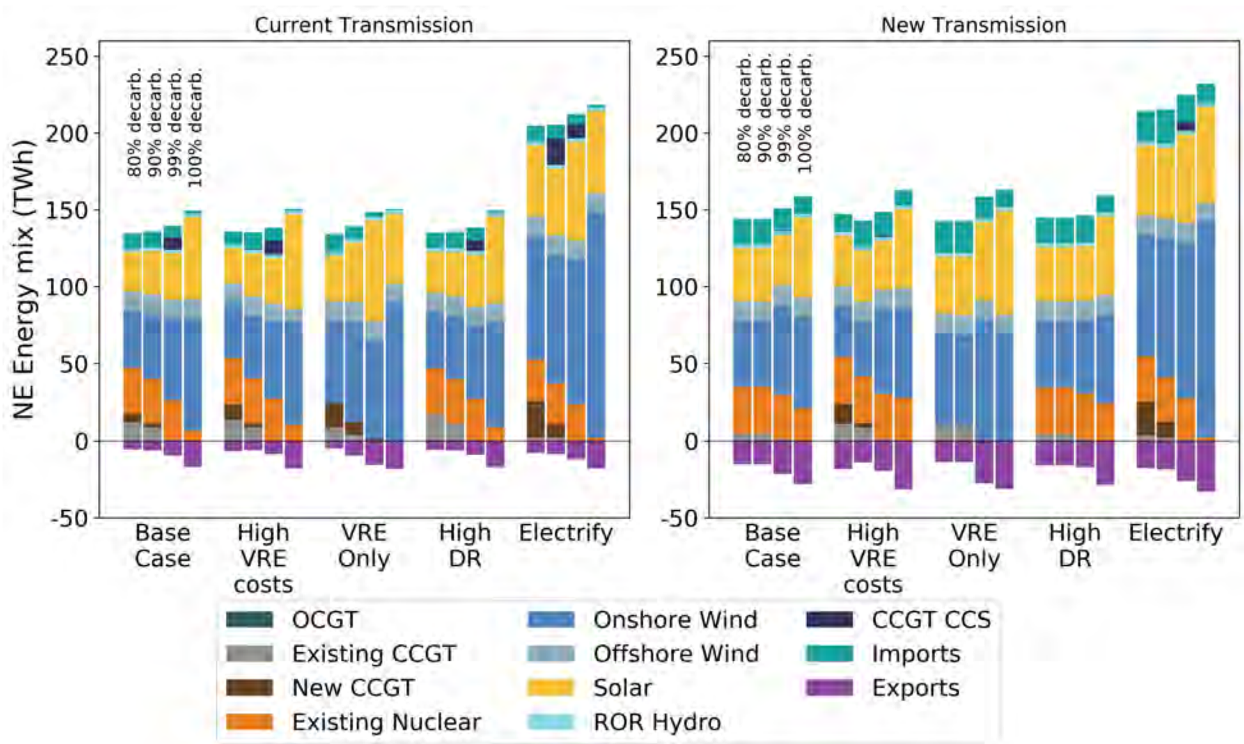

Figure 28: Energy mix in New England in 2050 by scenario and case

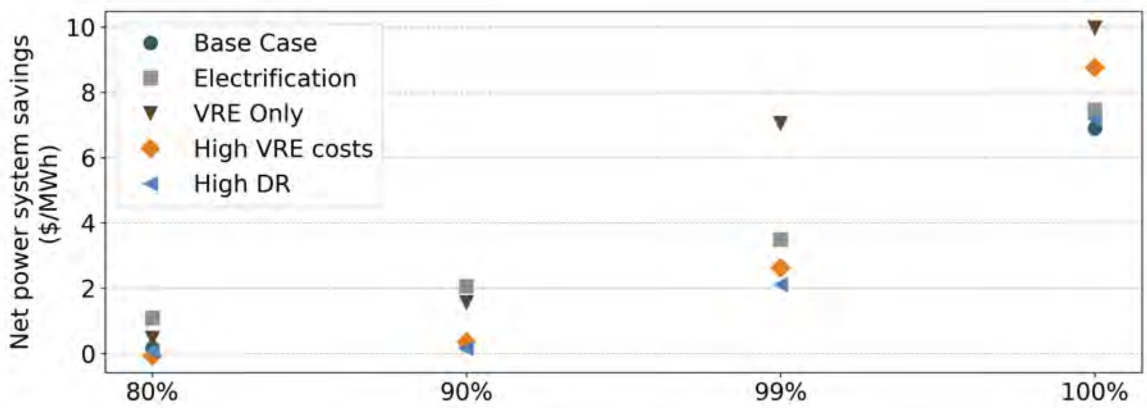

Figure 29: Net power system economic benefit of new transmission (4 GW) across New England and Quebec

4.3.4 Electrification of end-use sectors

We further explore the impact of electrification on our results. For this purpose, we use 2050 hourly load data for New England from the "High" electrification scenario by Mai et al. (2018b). The NREL High electrification scenario represents transformational electrification in multiple demand sectors, at a level that could be achieved through a combination of technology breakthroughs, policies, and behavioral changes that support the adoption of specific electricity-consuming technologies. For example, 88% and 81% of light-duty vehicles and trucks respectively in the US are electric; air-source heat pumps are installed in 107 million US residences; and heat pumps represent 60% of industrial space heating demand.

Figure 30 shows the difference between NREL's High electrification scenario and NREL's Reference scenario (the latter is used in our Base Case results) for the average day in 2050. The NREL High electrification scenario includes a higher evening peak, driven by electricity demand from heating and electric vehicle charging. As illustrated in Figure 30, electrification also leads to higher load in the winter months, with January featuring higher load than July, the highest-load month in the NREL Reference scenario.

The optimal mix now features more significant investments in CCGTs with and without CCS (Figure 28, where this case is denoted as "Electrify") relative to our Base Case. Deep decarbonization also results in a larger build out of variable renewable capacity and battery storage (Figure 27) relative to our Base Case. The optimal energy mix in Quebec is similar to our Base Case and comprises existing reservoir hydro and solar.

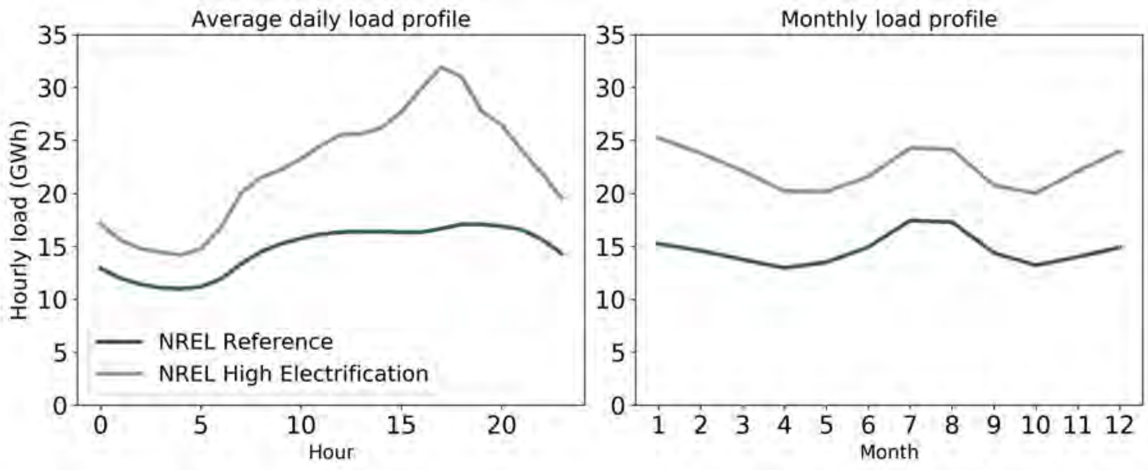

Figure 30: Effects of varying electrification assumptions on electricity demand in New England

Data source: Mai et al. (2018)

Even though both New England and Quebec have winter-peaking demand in this case, new transmission continues to be valuable as a means of expanded two-way trading. As shown in Figure 28, additional transmission increases trading in both directions. As in our Base Case, the addition of new transmission increases daily, synoptic, and seasonal balancing (imports from Quebec increase during the summer months and exports to Quebec increase during the Spring).

Transmission expansion also leads to power system cost savings in the case of electrification (Figure 29). In the New Transmission scenario relative to Current Transmission, total power system cost savings across New England and Quebec equal \$1, \$2, \$4, and \$7 per MWh in the 80%, 90%, 99%, and 100% decarbonization scenarios respectively. This is equivalent to relative savings of 5%, 8%, 12%, and 17% respectively. In the 80% decarbonization scenario, new transmission reduces costs primarily through savings on new CCGT plants (without CCS). For 90% decarbonization, new transmission reduces costs by obviating the need for investment in and operation of CCGTs with CCS. In the 99% decarbonization scenario, savings come primarily from New England fixed costs related to solar, batteries and CCS. And for 100% decarbonization, savings result from reduced investment in wind, solar, and batteries in New England.

5 Conclusion

5.1 Quebec hydro as a virtual energy storage resource

Achieving deep decarbonization of Northeastern U.S. electricity systems in a cost-effective manner requires expanding the use of low-cost variable renewable energy resources such as wind and solar PV. As a result, a predominant feature of low-carbon electricity grids will be the intermittency of electricity supply produced with wind and solar technologies. As grids become increasingly renewable, achieving additional emission reductions will come at an increasing cost, as planners look to more expensive low-carbon technologies to compensate for the variability of renewable energy. This paper's main conclusion is that Northeastern states can mitigate the challenge of intermittency through the use of existing hydropower reservoirs in Quebec.

The optimal use of U.S.-Canadian transmission lines will change drastically as Northeastern states decarbonize their power systems. Today transmission capacity is used to deliver energy south, from Quebec to the Northeast. Thus, the role of Quebec hydro in Northeastern power systems is as a generation source. Our results suggest that, in a future low-carbon grid, it is economically optimal to use the transmission to send energy in both directions, independent of a variety of assumptions we tested. Quebec imports energy (decreasing hydropower output and allowing reservoir water levels to rise) during periods when generation from zero-marginal-cost renewable energy in the Northeast is relatively high, and exports energy (drawing down reservoir levels) in periods when renewable scarcity in the Northeast drives electricity marginal costs up. Therefore, as Northeastern states decarbonize, the role of Quebec's hydropower for the Northeast increasingly becomes that of a virtual energy storage resource rather than a generation resource. Two-way trading of electricity with Quebec helps Northeastern states balance renewable intermittency at multiple time scales, mitigating the daily mismatch between solar and evening peak demand, the synoptic (multi-daily) mismatch between demand and wind output, and the seasonal mismatch between high summer demand and low summer wind output.

5.2 New transmission as complementary to building Northeastern renewable capacity

Transmission expansion enables Quebec hydro to play a greater balancing role in future low-carbon power systems in the Northeast, a finding robust to all alternative assumptions tested.

Across deep decarbonization scenarios, new transmission between Northeastern states and Quebec increases both imports from and exports to Quebec, allowing trading to further complement intermittent renewables. If we employ an analogy of Quebec's reservoirs as a battery for Northeastern power systems, more transmission to Quebec effectively increases the rate at which this battery can be charged and discharged. The role of Quebec hydro as a storage resource suggests that building additional transmission is a complement to deploying clean energy in the Northeast, rather than a substitute. This is in contrast to current plans by Massachusetts to use new transmission to import energy that substitutes for output from retiring nuclear capacity. In the near term, new transmission will likely result in more imports. However, we show that, in the longer term, cost effective decarbonization entails that states build wind and solar PV plants and utilize transmission with Quebec to manage their intermittency.

Investment in new transmission capacity also allows Northeastern states to reduce reliance on gas plants, which are otherwise called upon in periods of low renewable output. The displaced gas generation is replaced by output from wind, solar, and nuclear in the Northeast, and imports from Quebec, depending on the scenario. In our 80% decarbonization scenarios, gas generation is displaced by wind and solar generation in the Northeast (with the exception of the "Electrification" case in New England). This suggests that new transmission can increase the share of clean electricity, thus speeding up the transition toward zero-carbon energy systems. In our 80% decarbonization scenario for New England, new transmission increases the share that variable renewables contribute to New England demand from 60% to 72% (in our central Base Case results). In our New York analysis, this share rises from 64% to 78%. This finding was however not present across all sensitivities tested in Section 4.3. Transmission expansion also reduces the need for CCS gas plants in relatively deep decarbonization scenarios. This reduces decarbonization costs (see next sub-section) but also lessens dependence on additional considerations associated with CCS such as future cost uncertainty, infrastructure investment, and storage leakage risk.

Our results also show that the additional balancing services made possible by transmission expansion stem not from investments in new hydropower reservoirs but from changes in the operation of the existing hydropower resource. As a result, new transmission is not associated with GHG emissions from new hydropower impoundments. New Quebec hydro investments are not justified in our model. This result is sensitive to wind and solar costs as we showed in section 4.3. However, even when we assume 50% higher variable renewable costs, new hydro investments are not economical in our 100% decarbonization scenarios.

As a result of reduced gas dependence, new transmission lowers CO2 emissions across New England, Quebec, and New York. Our central Base Case results show that 4 GW of additional transmission between New England and Quebec reduces annual CO2 emissions by 5 Mt and 2 Mt in the 80% and 90% decarbonization scenarios. The same amount of new transmission between New York and Quebec reduces annual emissions by 6 Mt and 1 Mt respectively. Emission reductions occur across alternative cases with the exception of our high renewable costs and electrification cases where emissions are unchanged. Previous literature has likewise found that building new transmission between New England and Quebec reduces CO2 emissions in New England but has argued that this abatement may be offset by higher emissions in other jurisdictions. For example Energyzt Advisors (2018) argue that CO2 reductions in New England caused by imports from Quebec may be associated with a reduction of exports from Quebec to New York or Ontario, thus causing more gas generation in these jurisdictions. Any CO2 reductions in New England are therefore claimed to be non-additional. However, we show that CO2 abatement in New England is driven by a change in the timing of imports from Quebec (the utilization of Quebec hydro as an energy storage resource) rather than from importing more hydro energy throughout the year that Quebec could have exported elsewhere. We find that new transmission between New England and Quebec does not change emissions in New York (and similarly new transmission between New York and Quebec does not change emissions in New England). We have not explicitly modeled whether new transmission between Quebec and the Northeast U.S. would influence gas generation in Ontario. However, our model maintains hourly net exports from Quebec to Ontario (as well as New Brunswick) at historical levels in all scenarios. This demonstrates that Quebec's existing reservoir hydro can provide additional balancing services to New England or New York while maintaining sales to its other export markets.

We emphasize that the effects of transmission expansion analyzed in this paper occur in the long term when Northeastern electricity generation is modeled to be predominantly renewable. Therefore, this research does not address the merits of building new transmission lines in the near term.

5.3 Transmission expansion reduces the costs of decarbonization

State goals for zero-emission electricity will be achieved at a lower cost if transmission with Quebec is expanded according to our results. We find that new transmission delivers net electricity cost savings (after accounting for the cost of new power lines) for decarbonization levels beyond 90%. For New England, we estimate that 4 GW of additional transmission reduces power system costs across New England and Quebec by \$3/MWh (12%) in a 99% decarbonized power system and by \$7/MWh (24%) in a 100% decarbonized power system in our central Base Case. For New York, we estimated savings across New York and Quebec of \$3/MWh (12%) and \$8/MWh (23%) respectively. As we show in our sensitivity analysis (Section 4.3), savings are greater if states pursue a renewable-only approach to decarbonization (without the participation of nuclear and CCS), or if states achieve deep electrification of other energy end-use sectors including transportation, heating, and industry. These economic benefits do not factor in the value of the CO2 emission abatement estimated to result from new transmission.

It remains to be determined how these savings will be shared between Northeastern states and Quebec. The impact of new transmission on Northeastern electricity costs is contingent on the cost of imported energy from Quebec and on revenues from exported energy to Quebec.

5.4 Future research directions

Construction of transmission lines between the Northeast and Quebec will depend on additional considerations not represented in our modeling such as ecological impacts, positive or negative local community impacts, and GHG emissions associated with changes in the operation of existing reservoirs or facility-specific GHG emissions resulting from any new reservoir impoundments. We have also not considered several emerging technologies that may play a role in a future low-carbon grid such as green hydrogen or new long-term storage technologies. Our paper has not explored non-economic limitations on the amount of wind or solar capacity that can be deployed in Northeastern states. New capacity may face challenges due to siting concerns and constraints on intra-regional transmission expansion. Such constraints may limit the value of Quebec hydro as a balancing resource for Northeastern renewables. Similarly it would be beneficial to explore the impact that trading with Quebec may have on the needs for intra-regional transmission and distribution. Another topic for future work is how inter-annual variability in renewable availability, load, and Quebec hydro in-flows may impact the value of inter-regional trading.

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MIT Center for Energy and Environmental Policy Research
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139
USA

Website: ceepr.mit.edu

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Energy Policy 155 (2021) 112369

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The role of hydropower reservoirs in deep decarbonization policy

Emil G. Dimanchev *, Joshua L. Hodge, John E. Parsons

Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA, 02139, USA

ARTICLE INFO

Keywords:
Climate change mitigation macro-energy systems decarbonization hydropower energy systems engineering power system planning

ABSTRACT

This paper analyzes the role of hydropower reservoirs in the deep decarbonization of power systems. Extending previous work, this study models the impact of hydro reservoirs on optimal planning decisions. It further provides a more holistic assessment of the role and economic value of hydro reservoirs through the use of a detailed capacity expansion and dispatch model. Our model is parameterized based on the power system of New England, U.S. and the hydro-based system of Quebec, Canada. We find that expanding transmission access to hydro reservoirs reduces the need for fossil-fuel power plants that may otherwise be deployed to balance renewable intermittency. Our results show that hydro access can accelerate decarbonization by decreasing optimal gas plant capacity and generation. At levels of very deep decarbonization, reservoir hydro reduces the need for Carbon Capture and Storage. Our modeling shows how hydro reservoirs accomplish this by serving as both a short- and long-term energy storage resource. We further show that, by reducing the need for more expensive balancing technologies and by enabling a more efficient utilization of variable renewables, hydro access lowers the cost of decarbonization, and that this benefit grows non-linearly with the decarbonization target.

1. Introduction

Meeting global climate policy targets will likely require the complete or near complete decarbonization of electricity. Plans for decarbonizing the electricity sector tend to rely more or less heavily on variable renewable resources such as wind and solar technologies (Jenkins et al., 2018). There is disagreement however about what additional technologies are best suited to compensate for renewable intermittency. Decision makers have to plan for intermittency at multiple scales including diurnal, synoptic (weekly), and seasonal.

Previously studied solutions include firm low-carbon technologies such as nuclear and gas plants equipped with Carbon Capture and Storage (CCS), flexible demand, Li-ion batteries, long-term storage technologies, and power-to-gas production of synthetic fuels such as hydrogen (Brown et al., 2018b; Krey et al., 2014; Sepulveda et al., 2018; Davis et al., 2018). Another currently available technology that may complement variable renewables is reservoir hydropower. Such resources are available in a number of countries in North America, South America, Europe, and Asia (Gernaat et al., 2017; Rodríguez-Sarasty et al., 2021).

Hydro reservoirs use dams to stem waterflow, providing operators control over the scheduling of power output. Previous research at the technology level has demonstrated hydro reservoirs can be flexibly dispatched to respond to variations in renewable energy (Sørensen, 1981; Vergara et al., 2010; Korpaas et al., 2013). This is done by scheduling power production for periods of low renewable availability and letting water inflows accumulate behind the dam during other periods. To understand the broader implications of this flexibility, the role of reservoirs should also be examined at the systems level.

Previous studies on the effects of reservoir hydro on power systems vary by their chosen experimental design and methodology. With regard to experimental design, some authors have quantified the impacts of building new hydro power capacity (Wolfgang et al., 2016; Graabak et al., 2019). Others have explored the impacts of providing power systems with transmission access to existing hydro resources (Sørensen, 1981; Korpaas et al., 2013; Williams et al., 2018; Bouffard et al., 2018; Calder et al., 2020), a category to which this paper belongs. With regard to methodologies, two main approaches have been used: dispatch modeling, which represents short-term system operation; and capacity expansion modeling, which represents long-term system investment planning. Authors using dispatch modeling demonstrated the potential of hydro reservoirs to balance renewable intermittency (Wolfgang et al., 2016) and lower electricity costs (Graabak et al., 2019; Williams et al., 2018). However, this research did not consider how hydro may impact investment planning decisions (Graabak et al., 2019; Williams et al., 2018; Korpaas et al., 2013; Wolfgang et al., 2016), contribute to deep

* Corresponding author.
E-mail address: emild@mit.edu (E.G. Dimanchev).

https://doi.org/10.1016/j.enpol.2021.112369
Received 13 December 2020; Received in revised form 3 May 2021; Accepted 5 May 2021
Available online 20 May 2021

decarbonization targets (Graabak et al., 2019; Wolfgang et al., 2016; Bouffard et al., 2018), or interact with other balancing technologies such as batteries or CCS plants (Graabak et al., 2019; Wolfgang et al., 2016; Bouffard et al., 2018). This paper addresses all three gaps. Researchers have also used capacity expansion modeling to explore the role of hydro in future technology portfolios but have excluded dispatch modeling of its potential to balance renewable intermittency (Carvajal et al., 2019).

Understanding the effects of an electricity technology on future power systems requires a cohesive analysis of its impact on both the planning and operation of power systems (de Sisternes et al., 2016). For this reason, state-of-the-art optimization modeling today combines long-term capacity expansion and short-term dispatch modeling in a combined co-optimization approach (Jenkins and Sepulveda, 2017). While such studies have analyzed power systems with hydro resources, this literature has not isolated the effects of hydro on the rest of the system (Schlachtberger et al., 2017; Liu et al., 2019; Brown et al., 2018b; Jacobson et al., 2017; Barbosa et al., 2017; Rodríguez-Sarasty et al., 2021). This is another gap addressed by our paper. Through the use of a co-optimization model that represents both long-term investment planning and short-term dispatch, this paper explores the impact of hydro reservoirs on both power system operation and on optimal investment planning.

This paper contributes to prior literature in four main ways. First, our holistic methodology allows us to study how hydro's ability to balance intermittent renewables in the short term impacts long-term power system planning. It also enables us to provide a comprehensive calculation of the economic value of hydro access. Hydro access decreases the need for gas plant capacity and generation, thus reducing cost as well as facilitating decarbonization. Optimizing the short-term dispatch of reservoir hydro to balance intermittent renewables enables a more efficient utilization of wind and solar resources which then motivates expanded investment in wind and solar capacity at lower levels of decarbonization. Second, our modeling features a richer set of technologies not included in previous studies such as CCS (including associated unit commitment constraints), demand response (Graabak et al., 2019; Williams et al., 2018; Wolfgang et al., 2016) and battery storage (Graabak et al., 2019; Wolfgang et al., 2016). This enables us to analyze the role of hydro relative to other balancing technologies. Third, this paper analyzes the role of hydro for a range of deep decarbonization targets, which we define as featuring emission reductions greater than 80%. At stringent decarbonization levels, seasonal renewable intermittency presents a key challenge. We show that reservoir hydro addresses intermittency at multiple scales ranging from hourly to weekly to seasonal. The benefits of utilizing reservoir hydro for balancing are further shown to be non-linear, increasing sharply as decarbonization approaches 100%. We show not only that it is optimal to change the utilization of existing hydro capacity, but also that expanded transmission capacity is valuable because it enables further exploitation of existing hydro capacity for balancing. Fourth, this paper features a number of sensitivity cases, including a case containing substantial electrification of energy consuming sectors, an increasingly pertinent trend in decarbonization planning, not considered in prior work (Wolfgang et al., 2016; Korpaas et al., 2013; Graabak et al., 2019).

The rest of this paper is organized as follows. Our methodology is described in section 2. Results are then described in section 3. Section 3.1 discusses the role of reservoir hydro access in a deeply decarbonized power system, which provides context for subsequent results. Section 3.2 explores the effects of increasing power system access to reservoir hydro via the construction of new transmission to a hydro-rich region. In section 3.3, we quantify the economic value of hydro access. Section 4 reaches general conclusions and discusses policy implications.

2. Methodology

2.1. Experimental design and model description

Our experimental procedure seeks to isolate the effects that access to hydro reservoirs has on the planning and operation of a general power system under deep decarbonization targets. Specifically, we quantify how utilizing an available hydro resource for balancing enables increased utilization of low-cost renewable resources. We then quantify the impacts of increasing transmission between a power system and a neighboring hydro-rich region. For this purpose, two main scenarios are used: Current Transmission and New Transmission (described in Table 1). These scenarios are run for a range of climate targets and sensitivity cases representing variations in important assumptions.

We parameterize our model using data on New England, U.S. and Quebec, Canada. Quebec represents the hydro-rich region in our analysis. It operates a large reservoir hydro system, which supplies 96% of its electricity (Statistics Canada, 2019b). The New England power system is chosen to represent a power system significantly reliant on thermal generation. It features a wide set of technologies - generally available to power system planners in various jurisdictions - but lacks reservoir hydro resources. Decarbonization goals in New England states have given rise to discussions about building new transmission lines to increase access to hydro reservoirs in Quebec (Commonwealth of Massachusetts, 2018). This case is qualitatively generalizable to similar discussions on connecting hydro resources to electricity systems in Canada (Dolter and Rivers, 2018), Europe (Korpaas et al., 2013), China (Liu et al., 2019), and other U.S. states (Minnesota Department of Commerce, 2020; Calder et al., 2020).

To perform these experiments, we introduce a detailed implementation of the capacity expansion and dispatch model GenX (Jenkins and Sepulveda, 2017). GenX is a constrained optimization model that determines the least-cost mix of electricity technology investments as well as the least-cost set of operational decisions to meet electricity demand at all chosen time periods. We model the year 2050 and use the model to derive optimal investment and operational decisions to meet demand for all 8760 hours of the year. This full annual representation ensures a rigorous treatment of renewable intermittency, capturing statistical correlations between weather-dependent time series and system-defining extreme points, which has previously not been achieved by models using representative time periods (Pfenninger et al., 2014).

We further represent the short-term operation of the power system at a high detail by modeling unit commitment decisions. Unit commitment has traditionally been omitted in large-scale planning models due to high computational complexity at the expense of model accuracy (Palmintier and Webster, 2011). This paper balances accuracy and computational considerations by using a linearized clustering technique (Jenkins and Sepulveda, 2017).

The geographic scope of our model includes New England, Quebec, and New York. The New York power system is also assumed to decarbonize (by 90% in all of our scenarios) and to place demands on the Quebec hydro resource. It was therefore considered important to include it in the model as a de facto endogenous constraint on the Quebec system's ability to trade electricity with New England. Transmission capacity between regions is based on up-to-date data detailed in Supplementary Material section 1.1. We further account for demand placed on the Quebec system by trade with Ontario and New Brunswick. This is done in a reduced-form fashion by using historical hourly power exports from Quebec to these jurisdictions and adding them to Quebec load (see the Supplementary Material section 1.6 for further details).

2.2. Technology assumptions

Technology cost data is based on 2050 medium-cost projections by the National Renewable Energy Laboratory (NREL) (NREL, 2019a), unless otherwise specified. All technology types and costs are shown in

Table 1
Policy scenarios.

Scenarios	Transmission between New England and Quebec	Decarbonization target in New England	Sensitivity Cases
Current Transmission	Current (2.225 GW)	80%, 90%, 99%, 100%	See Table 2
New Transmission	+4 GW (6.225 GW)	80%, 90%, 99%, 100%	See Table 2

Table 2
Sensitivity cases.

Case	Description
Base Case	Assumptions described in Methodology and Supplementary Material
High VRE Cost	The investment cost for Variable Renewable Energy (VRE), which includes wind and solar, is 50% higher relative to Base Case
Low VRE Cost	VRE costs equal the "Low" 2050 projection by NREL (2019a). Investment costs are lower by 44%, 48%, and 11% for solar, onshore wind and offshore wind respectively relative to Base Case. Fixed O&M costs are 42%, 14%, and 9% lower respectively.
Low Li-ion Cost	Battery costs equal the "Low" 2050 projection by NREL (2019a). Investment costs are lower by 56% relative to Base Case. Fixed O&M costs are 59% lower.
VRE Only	CCS and nuclear technologies are not available
High DR	Demand response technology can shift 20% of load rather than 5% in the Base Case
Electrification	New England electrifies transportation, heating, and industry using hourly electricity load data for 2050 from the "High Electrification" scenario in Mai et al. (2018).

Tables S3-5 in the Supplementary Materials. New power technologies and their assumed fixed costs and associated financial parameters are listed in Table S2. We annualize costs using the financial methodology employed by NREL (2019a). The Weighted Average Cost of Capital (WACC) for Li-ion batteries is calculated based on financial assumptions (NREL, 2019a) as well as debt fraction and capital recovery period assumptions (Lazard, 2018). Variable costs and heat rates are displayed in Table S3. Start-up costs and operation constraints are shown in Tables S4 and S5 and are both sourced from MIT (2018).

The model includes a rich set of technologies, which are additionally differentiated by existing plants projected to be available in 2050 and new technologies. Please see Supplementary Material section 1.3 for a detailed description of our plant-level analysis used to determine existing technologies in 2050.

Additionally, we specify a number of engineering constraints on energy storage and demand flexibility, described in detail in the Supplementary Material section 1.4. Finally, transmission costs are specified based on historical regional project data and financial calculations described in the Supplementary Material section 1.8 and Table S6.

2.3. Hourly electricity system data

Our model uses detailed electricity system data at the hourly resolution. Hourly electricity demand data is based on 2050 load data for New England and New York (Mai et al., 2018). This data is based on 2012 weather patterns. We therefore use 2012 data for all weather-dependent variables, including renewable capacity factors, to account for statistical associations between these variables (with the exception of reservoir hydro inflow data in Quebec due to data limitations). For electricity demand, we use the "Reference" scenario by Mai et al. (2018). All load data uses the "Moderate" assumption for the efficiency of electrification technologies and "Base" demand flexibility parameters. Demand in New England and New York grows by 0.3% and 0.2% per year respectively up to 2050. The Electrification case uses data from the "High" electrification scenario (also assuming "Moderate" end use efficiency and "Base" load flexibility) (Mai et al., 2018).

For Quebec load, we use hourly data for 2012 (Regie de l'energie), and assume an annual growth rate of 0.4% consistent with projections by Hydro Quebec Distribution for the next decade (Hydro Quebec Distribution, 2019) and long-term projections (Williams et al., 2018). The load duration curves for all three regions are displayed in Figure S2.

Several approaches are combined to model hourly availability of intermittent renewables in all regions. Hourly capacity factors for onshore and offshore wind for New England and New York are compiled by accessing the API for the NREL Wind Toolkit dataset of hourly power output at potential wind turbine site locations. These are then used to compute regional average capacity factors. For Quebec, onshore wind capacity factors are estimated based on modeled power output using 2012 wind speed data from the NREL's gridded atmospheric WIND Toolkit (NREL, 2019b) and power curves described in Draxl et al. (2015). We use spatial GIS techniques to derive a map of Quebec excluding metropolitan areas and national parks (Statistics Canada, 2019a) and overlay this map with our wind data to derive hourly regional average capacity factors. Solar capacity factors in all regions are estimated by modeling power output for a representative PV system at a large number of points uniformly spread across each region. We assume PV systems are one-axis east-west tracking with 0-degree tilt based on the most common utility-scale project design (Bolinger et al., 2019). Insolation data is sourced from the National Solar Radiation Database (Habte et al., 2017). We use the PV model and default PV system assumptions developed by Brown and O'Sullivan (2019). Run-of-river capacity factors in New England and New York are calculated by dividing monthly 2012 generation from EIA (2013) by capacity from EIA (2019). Resulting capacity factor data for wind, solar, and run-of-river hydro are displayed in Figure S3. For Quebec, water inflows into hydropower reservoirs sourced from Hydro Quebec (2019) are displayed in Figure S4.

2.4. Modeling hydropower reservoirs

The operation of the reservoir hydropower system of Quebec is modeled as a single unit, with a generation capacity equal to the combined capacity of reservoir and run-of-river hydro in Quebec in 2050, reflecting Quebec's cascading hydro systems, which feature run-of-river plants downstream of hydro reservoirs (see sections 1.3 and 1.4 of the Supplementary Material for a detailed description of how the technological and economic characteristics of the system are parameterized). The operation of the reservoir is optimized through the year based on perfect foresight of power system conditions, subject to a number of constraints provided by Hydro Quebec (2019). Water inflows (shown in Figure S4) are provided at a monthly resolution based on average long-term historical hydrological conditions (Hydro Quebec, 2019). Hydro generation must run at least at 27% of its capacity to account for downstream ecological management and transmission grid stability constraints. We also constrain the ramping speed of reservoir hydro to 14% of total capacity per hour, in line with current operational practices and constraints (Hydro Quebec, 2019). In the Supplementary Material, we test the sensitivity of our results to changes in inflows, reservoir size, and ramping speed.

Although we do not explicitly model stochastic optimization in the face of uncertainty, we impose two additional constraints that reflect how uncertainty should constrain the optimization. First, we require that the reservoir be not more than 55% full at the beginning of the Spring (specified in the model as May 1), a level deemed appropriate to reliably absorb spring flows (Hydro Quebec, 2019). Second, we assume that the year begins with the reservoir 70% full and we require that the reservoir again be 70% full at the end of the year, reflecting the normal precaution against inter-annual uncertainty in flows (Hydro Quebec, 2019).

This aggregate and deterministic representation of reservoir hydropower is simplified relative to methods that explicitly model river systems, individual plants, and water flow interdependencies in a bottom-up fashion (Rodríguez-Sarasty et al., 2021) and use stochastic optimization to determine optimal operation (Korpaas et al., 2013). The approach we take is commonly used for representing hydropower in system-level studies (Dolter and Rivers, 2018; Brown et al., 2018b, e.g.). The advantage of a simpler approach is its computational tractability, which enables a greater number of scenarios and sensitivities as well as the representation of other relevant details such as operational details and technological resolution. While the flexibility of hydro may be less accurately represented under a simplified approach relative to bottom-up modeling (Rodríguez-Sarasty et al., 2021), our choice of constraints is intended capture real-world operational limits. Previous work has validated models with aggregate representations of reservoir hydro (Lie et al., 2017; Brown et al., 2018a). The approach has also been shown to compare well to highly detailed models using bottom-up modeling (Brandão, 2010) and stochastic optimization (Korpaas et al., 2013). Similar aggregation approaches have also been shown to maintain an adequate accuracy relative to more detailed models (Härtel and Korpå). At the same time, further investigation into the robustness of these results within a more detailed model of the hydro system and one using stochastic optimization would be a valuable.

3. Results

3.1. Optimal deep decarbonization leverages complementarity between variable renewables and hydro reservoirs

Cost-optimal deep decarbonization entails the expansion of wind and solar and the extension of existing nuclear plant lifetimes (left panels in Fig. 1 and Fig. 2). Offshore wind is part of the mix in line with existing policy mandates. To balance renewable intermittency, the power system uses trading with Quebec's hydro-based system, gas plants, demand response, and Li-ion batteries. The relative prominence of different balancing options varies by the level of decarbonization. Very deep decarbonization of 99% includes investment in gas with CCS. For 100% decarbonization, CCS is no longer part of the optimal mix due to our assumption of a 90% CO2 capture rate. Instead, our model expands wind and solar capacities to an extent large enough that demand can be met even during periods of low renewable availability, an approach which has been referred to as "oversizing" (Sepulveda et al., 2018). This is also accompanied by a high amount of renewable curtailment in New England equal to 47 TWh in the Base Case.

In Quebec, the optimal mix is mainly comprised of existing hydro reservoirs. New reservoirs are only built in the High VRE Cost case where wind and solar investment costs are 50% greater than in our Base Case. We note that new reservoir hydro is not built if we assume a 40% increase in costs, suggesting that our Base Case energy mix is robust to moderate changes in renewable costs.

In all of our scenarios, the hydro-based system of Quebec is both an importer and exporter of electricity (Fig. 1). The pattern of electricity trading reflects the way in which Quebec hydro reservoirs respond to New England renewable intermittency. Periods of high renewable availability result in low electricity prices in New England during midday hours and windy periods in the winter and spring. In such hours it is cheaper for Quebec to import than to use water in existing reservoirs, build new reservoirs, or build local wind and solar, which have poorer capacity factors than in New England. As a result, exports from New England rise together with its decarbonization target. Conversely, in hours of renewable scarcity, New England imports electricity from Quebec. This two-way trading reveals a mutual complementarity between the variable-renewable-based system of New England and the hydro-based system of Quebec.

Fig. 3 illustrates how the operation of reservoir hydro in Quebec counter-balances renewable intermittency in New England. The left panel shows that the reservoir hydro capacity factor (the hourly output divided by the maximum output capacity) is moderately correlated with net demand in New England (demand minus wind and solar output) for the 99% Base Case scenario, which is illustrative of our results. The coloring further shows that the correlation is stronger for comparable levels of Quebec electricity demand.

The two-way trading that characterizes the optimal system results is very different from the current utilization and vision for trade between New England and Quebec where hydropower has been seen as a source of "base load" electricity in U.S. states (Governor's Press Office, 2016) and contracts for future electricity exchanges between New England and Quebec envision electricity flowing unidirectionally from Quebec (Commonwealth of Massachusetts, 2018). Two-way trading leverages complementarity between New England renewables, which are intermittent but low-cost, and Quebec hydro reservoirs, which are flexible but constrained by scarce water inflows. We define the value of two-way trading as the difference in total power system cost across both regions between a scenario where power is constrained to only flow north-to-south to a scenario where it is allowed to flow in both directions. We estimate that this cost reduction is 5–6%, equivalent to cost saving of $1–2/MWh. (these estimates are for our Base Case and the range reflects variation across decarbonization targets).

3.2. Access to reservoir hydro has wide-ranging implications for power system investment and operation

Greater access to hydro reservoirs changes the optimal energy and capacity mixes as shown by our New Transmission scenarios (right panels in Figs. 1 and 2 respectively). For partial decarbonization of 80%, gas capacity decreases in all cases relative to the Current Transmission scenarios. This is driven both by retirements of existing plants and by a lack of new investments, which are no longer economically justified. Gas generation also declines in all cases (with the sole exception of the 80% High VRE Cost scenario where generation remains relatively unchanged). As gas plants are the only source of CO2 in our system, the decrease in gas generation reduces CO2 emissions by 5 Mt in the 80% "Base Case" decarbonization scenario relative to the Current Transmission, thus leading to an over-achievement of the climate goal.[1] Emissions also decrease in the 90% decarbonization scenario, by 2 Mt (Figure S10 shows detailed emission results across all scenarios and cases). These results suggest that access to hydro accelerates decarbonization.

While hydro access decreases gas generation, there is an accompanying increase in generation from wind, solar, nuclear or new reservoir hydro depending on the scenario (Fig. 1). In scenarios of partial decarbonization of 80–90%, the share of wind and solar in total New England-Quebec electricity consumption increases in all cases with the exception of those where firm resources remain relatively valuable even after the addition of new transmission (these are the High VRE Cost case and the 80% Electrification scenario where it is roughly unchanged). Nuclear generation also increases in many New Transmission scenarios as nuclear plants are ramped down less frequently. In the Current Transmission scenarios, periods of high renewable generation incentivize nuclear ramp-downs but this effect is mitigated in the corresponding New Transmission scenarios due to the increased ability to export excess renewable generation.

The effect of hydro access on variable renewable capacity varies by decarbonization scenario (Fig. 2). Under the 80% decarbonization goal,

[1] The 80% the carbon constraint is not binding in our modeling in the Current Transmission scenario. It is binding at all other Current Transmission decarbonization scenarios, 90%, 99% and 100%. The result at 80% calls out the fact that our Base Case projected costs for low carbon generation are low relative to the cost of carbon intensive generation.

Fig. 1. Impact of decarbonization and hydro access on optimal 2050 energy mix.
Each panel shows the lowest-cost mix of energy generation by source across different decarbonization goals (resulting emissions may differ if a goal is over-achieved). Top panels show results for New England and bottom panels for Quebec. Left panels refer to the Current Transmission scenarios. Right panels refer to the New Transmission scenarios (greater hydro access). OCGT: Open Cycle Gas Turbines; CCGT: Combined Cycle Gas Turbines; ROR: Run-of-river hydro; Imports/Exports refer to flows between New England and Quebec.

total variable renewable capacity across all regions increases in the majority of cases with the exception of those where firm resources remain relatively valuable (the High VRE Cost and Electrification cases). In scenarios of deeper decarbonization, the amount of optimal variable renewable capacity tends to be lower in the New Transmission relative to Current Transmission scenarios, as access to hydro enables a more efficient use of this capacity (for example, renewable curtailment decreases by 93% or 44 TWh in our Base Case 100% decarbonization scenario). As a result of both effects mentioned in this paragraph, the amount of variable renewable capacity in the New Transmission scenarios is more stable across decarbonization levels than in the Current Transmission scenarios.

Hydro reservoirs reduce the need for other resources for the balancing of renewables. In very deep decarbonization of 99–100%, greater hydro access reduces optimal battery storage investments (including in the "Low Li-ion Costs" case). In these scenarios, hydro access also displaces CCS capacity (Fig. 2) and generation (Fig. 1). These results stem from the value of reservoir hydro for both short-term, diurnal, balancing (where it competes with battery storage) and long-term, weekly to seasonal, balancing (where it competes with CCS). These underlying balancing effects are discussed in more detail in the following two paragraphs.

Fig. 3 illustrates how greater access to reservoir hydro in the New Transmission scenarios enables additional balancing of renewable intermittency. As shown in the right panel, reservoir hydro becomes more closely correlated with New England net demand relative to the Current Transmission scenario (left panel). Quebec's reservoir hydro increases output during periods of high New England net demand (renewable scarcity) and vice versa.

Access to reservoir hydro provides balancing at multiple temporal scales. Fig. 4 illustrates the difference in the capacity factor of reservoir hydro (left panel) and its water level (right panel) between the Current Transmission and New Transmission scenario for 99% decarbonization in the Base Case. The left panel shows that hydro utilization changes from week to week. Hydro output adjusts to balance weekly (synoptic) variations in New England wind output. Short-term balancing is further illustrated in greater detail in Figure S9 which shows technology-level hourly dispatch. Reservoir hydro also provides seasonal balancing as output shifts toward the summer, increasing by 18% in the second week of August (equivalent to 4 GW of power output), when New England net demand is relatively high due to low wind output. The right panel shows the seasonal energy storage service provided by reservoir hydro. The reservoir accumulates energy from periods when surplus New England energy is exported to Quebec and discharges in periods when Quebec exports energy back to compensate for scarcity in New England. In the Supplementary material, we show that the balancing effects of hydro access are consistent across sensitivity cases (Figure S5). Quebec hydro also provides diurnal balancing for New England (see Figures S6 and

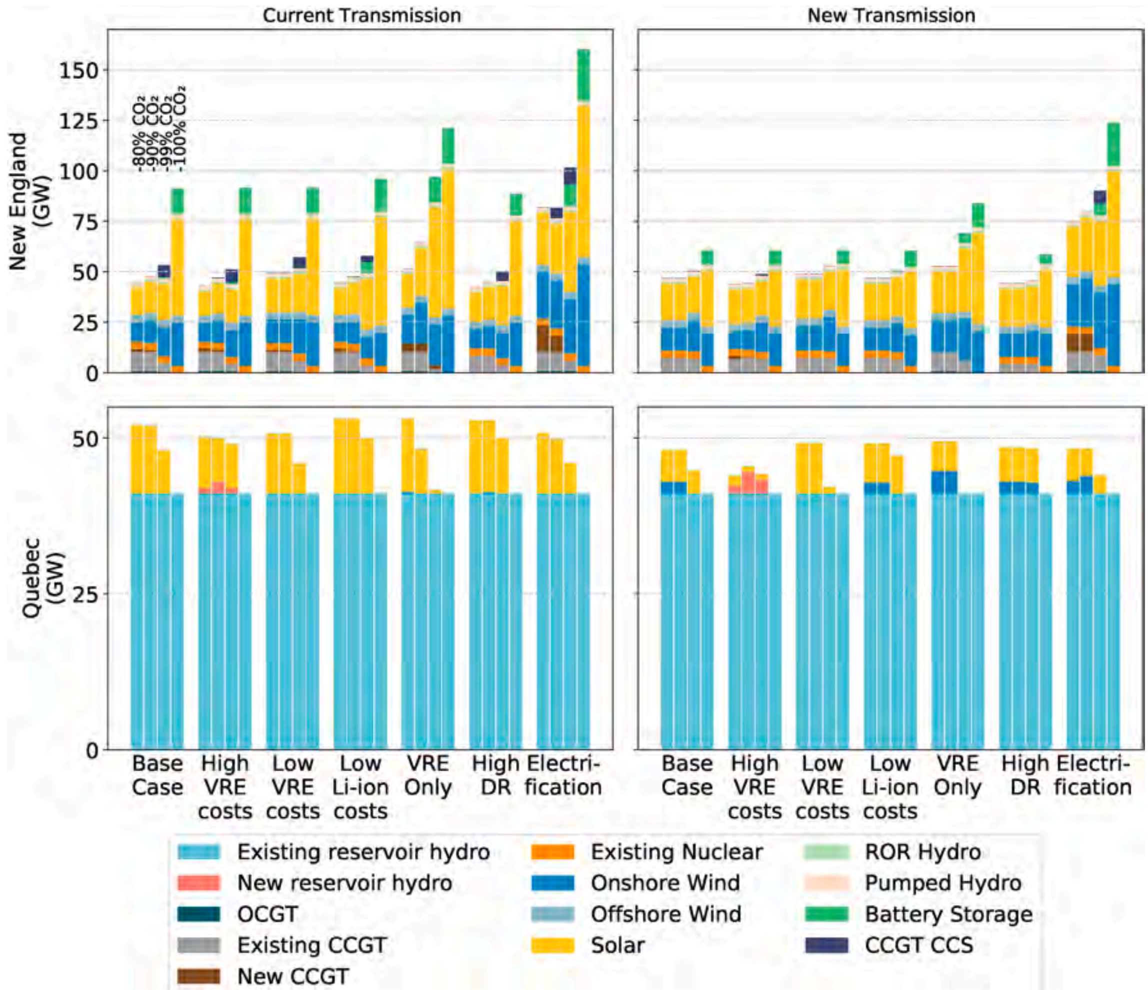

Fig. 2. Impact of decarbonization and hydro access on optimal 2050 capacity mix.
Each panel shows the lowest-cost mix of capacity by technology across different decarbonization goals (resulting emissions may differ if a goal is over-achieved). Top panels show results for New England and bottom panels for Quebec. Left panels refer to the Current Transmission scenarios. Right panels refer to the New Transmission scenarios (greater hydro access). OCGT: Open Cycle Gas Turbines; CCGT: Combined Cycle Gas Turbines; ROR: Run-of-river hydro.

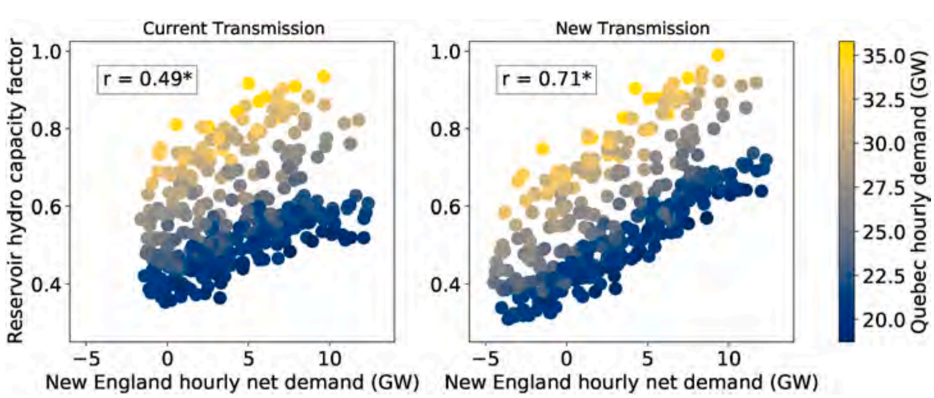

Fig. 3. Reservoir hydro counter-balancing of New England renewable intermittency.
Figure represents results for the 99% decarbonization Base Case scenario. Each dot shows the average hourly value for each day of the year. Net demand equals demand minus output from onshore wind, offshore wind and solar. *Correlation coefficients are calculated using all 8760 hours of the year, rather than the daily averages shown.

S7). The patterns of hydro utilization we discuss here also match the electricity exchange between the regions (Figure S8).

3.3. Access to reservoir hydro provides net economic benefit under very deep decarbonization

We define the systems value of hydro access as the saving in total power system cost across New England and Quebec in the New Transmission scenarios relative to the corresponding Current Transmission scenarios. The total system cost includes the cost of building and operating power generating assets (including technologies for energy storage and demand response), building new inter-regional transmission, and compensation for non-served energy. Fig. 5 displays the economic impact of hydro access on different power system cost categories and its overall value (denoted as “net cost”) across scenarios and cases.

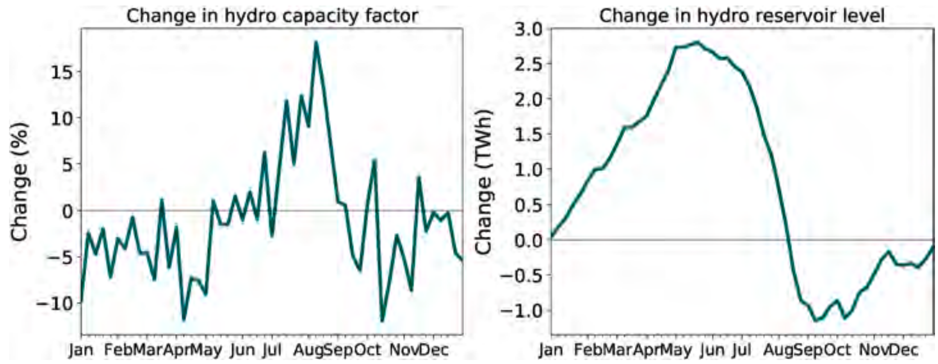

Fig. 4. Changes in reservoir hydro operation in response to renewable intermittency.
Panels show change from Current Transmission to New Transmission for 99% decarbonization under "Base Case" assumptions. Left panel shows change in hourly hydro capacity factor averaged for each week of the year. Right panel shows change in hourly water level in terms of energy averaged for each week of the year.

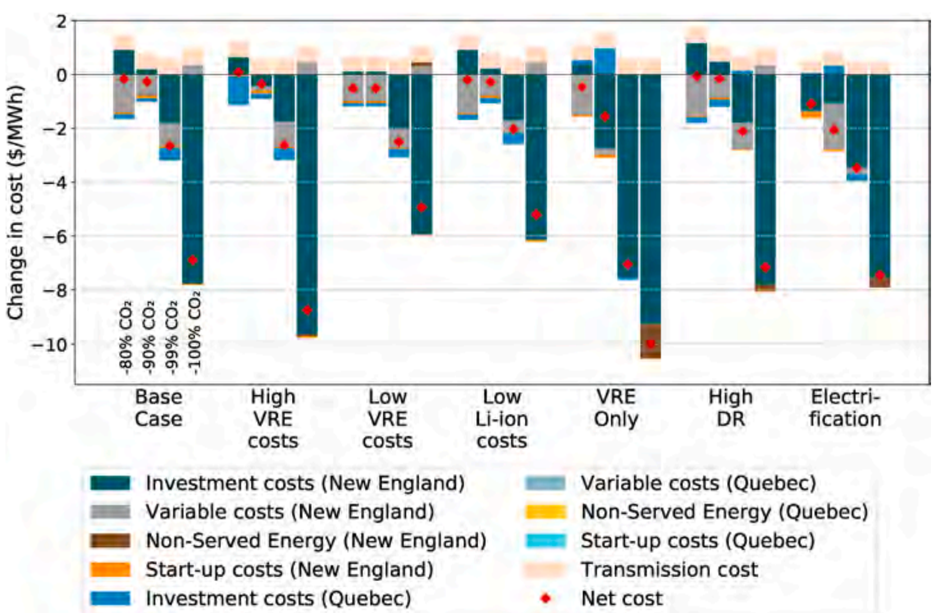

Fig. 5. Economic value of transmission between New England and Quebec.
Figure shows the change in cost of electricity across New England and Quebec between the Current Transmission and New Transmission scenarios. The cost of each category represents total cost in that category divided by total electricity demand across New England and Quebec. The "Net cost" change represents the value of hydro access.

With a decarbonization target up to 90%, the economic value of hydro access is approximately neutral. This occurs as variable and investment cost savings from gas plants are offset by higher investment costs in renewables and transmission capacity (Fig. 5). Under very deep decarbonization of 99% or 100%, the 4 GW of additional transmission to Quebec provide a net saving of $3/MWh and $7/MWh respectively in our Base Case (equivalent to total savings of $913 and $2387 million/year, or a reduction in power system costs of 13% and 24%). Across all cases, savings are in the range of 10–26% and 17–28% in the 99% and 100% decarbonization scenarios respectively. The source of the net economic benefit of hydro access varies across scenarios. In the 99% decarbonization scenarios, it stems primarily from savings on investment in gas plants with CCS and operation costs. In the 100% decarbonization scenario, it stems from savings from avoided oversizing of wind, solar, and Li-ion investments (Fig. 5).

The value of hydro access also varies across our modeling cases. Notably, it is relatively high if New England pursues an approach to decarbonization that excludes existing nuclear plants and CCS (as shown by the VRE Only case) because these technologies provided some back-up and balancing that now falls almost exclusively to reservoir hydro. In partial decarbonization scenarios, our model builds additional new CCGT plants in Current Transmission VRE Only scenarios than in our Base Case due to the additional need for back-up electricity to replace retired nuclear plants. Expanding access to reservoir hydro reduces the need for such investments. Under very deep decarbonization of 99–100%, additional trading with Quebec reduces the need to oversize wind, solar, and Li-ion batteries, which is called for in the Current Transmission VRE Only scenarios. The value of hydro access is also higher in our Electrification case. This is in part because this case requires a lower CO2 intensity of electricity to meet the same absolute CO2 target across a larger set of electricity-consuming sectors. New transmission reduces investment costs incurred from oversizing renewables in the 80% and 90% decarbonization scenarios, as well as CCS costs incurred for decarbonization of 90% and beyond. It is notable that the Electrification scenario causes New England's peak demand to shift from summer to winter, due additional heating demand. As Quebec is already a winter-peaking system, this may be expected to challenge the complementarity between the two systems. Our results show that this effect is not sufficient to detract from the value of transmission access between the two systems relative to our Base Case. Finally, the Low VRE Costs and Low Li-ion Costs cases reduce the value of hydro in the 100% decarbonization scenario, where the value of hydro stems from avoided investments in these technologies. However, these cases have limited impacts at lower levels of decarbonization where the value of hydro stems from, for example, avoided CCS investments, as discussed above.

4. Conclusion and policy implications

This paper shows that hydro reservoirs can play an important role in the planning of low-carbon power systems. Extending previous literature, this study models the impact of hydro access on optimal planning decisions. The results show that greater access to hydro reservoirs reduces optimal gas capacity (which at low levels of decarbonization is accompanied by expanded renewable capacity). This suggests that hydro access can help accelerate the phase out of fossil fuel capacity and thus the decarbonization of power systems.

This study also reaches novel insights regarding the role of reservoir hydro in system planning relative to other balancing technologies not considered in previous studies. We find that greater access to hydro reservoirs reduces optimal investments in CCS plants. This is shown to be the case even under substantial electrification, a scenario not typically considered in prior modeling. Hydro reservoirs therefore increase the feasibility of deep decarbonization by reducing dependence on new technologies and exposure to associated risks. A reduced need for CCS mitigates uncertainties with regard to future costs, CO2 infrastructure deployment, and CO2 leakage (our assumed CCS costs exclude the cost of CO2 transport and storage). Hydro access also reduces optimal investments in battery storage.

The value of hydro reservoirs is shown to derive from their balancing of renewable intermittency at multiple time scales. We study balancing in greater detail than previous studies by modeling demand flexibility, availability of batteries, and unit commitment constraints on thermal power plants. This paper shows that hydro reservoirs provide value by balancing renewables at the diurnal, weekly, and seasonal scales. Our results not only strengthen the case made in prior work showing the potential of reservoir hydro as an energy storage resource (Graabak et al., 2017), but we also show that hydro compares favorably against other balancing options such as CCS and batteries. We further show that the value of hydro reservoirs as a balancing resource is unaffected by increased flexible demand (as in our "High DR" scenarios).

We further estimate hydro access has a positive economic value and show that this value grows non-linearly with decarbonization. Previous work has shown that leveraging complementarity between different energy resources is particularly valuable under deep decarbonization (Sepulveda et al., 2018). This paper similarly finds that the flexibility of hydro reservoirs provides value as a solution to the unique challenges of deep decarbonization, such as synoptic and seasonal renewable intermittency. Additionally, we find that the value of hydro as a balancing resource is robust across a range of assumptions such as availability of competing balancing services from gas CCS plants, or changes in future demand from electrification of all energy-consuming sectors.

These results suggest that reservoir hydro could contribute to decarbonization efforts in jurisdictions, such as New England, which face the challenges of renewable intermittency and have the potential to access hydro reservoirs. While we have used data from New England and Quebec, our results are qualitatively generalizable to a number of similar power systems in proximity to a hydro-rich region. Such jurisdictions may include power systems in Europe (Graabak et al., 2019; Gleadow and Love, 2019), northern U.S. states (Minnesota Department of Commerce, 2020; Calder et al., 2020), Canada (Topp, 2019; Dolter and Rivers, 2018), Latin America (de Faria and Jaramillo, 2017; Carvajal et al., 2019), and Asia (Liu et al., 2019). We note, however, that the generalizability of our results is limited to the extent of similarity between other systems and the region studied here. Our economic analysis demonstrates the value in altering the utilization of already existing hydro resources. The estimated value of hydro is therefore primarily relevant for regions that are able to use existing hydro resources.

Our findings challenge the traditional role of hydro reservoirs in a number of jurisdictions. Hydropower has been seen as a source of "base load" electricity in U.S. states (Governor's Press Office, 2016). Contracts for future electricity exchanges between New England and Quebec envision electricity flowing unidirectionally from Quebec (Commonwealth of Massachusetts, 2018). In other jurisdictions, including Canadian provinces (Topp, 2019) and Latin American nations (de Faria and Jaramillo, 2017), hydropower has long served as the primary source of electricity. In both cases, power system planning would benefit from leveraging the value demonstrated in this analysis of hydro reservoirs as a balancing resource. In the former case, hydro balancing would help jurisdictions such as New England integrate renewables in the pursuit of decarbonization goals. In the latter case, jurisdictions formerly dependent on hydropower can diversify toward low-cost variable renewables and use existing hydro reservoirs to balance resulting intermittency. A first step toward maximizing the value of hydro as a balancing resource is the design of institutional frameworks and market signals ensuring optimal participation of hydro resources in regional and inter-regional markets.

While research has raised concerns about the GHG emissions from new hydro reservoirs (Hertwich, 2013; Scherer and Pfister, 2016), we find that considerable balancing of intermittent renewables can be accomplished with existing resources found in hydro-rich regions such as Quebec. Additional hydro investments are deemed uneconomical by our model (unless we increase assumed renewable investment costs by more than 40%).

An important limitation of this work is the use of a single meteorological year. Inter-annual variability in weather patterns induces substantial changes in renewable availability (Collins et al., 2018). Previous work found that single-year modeling can result in estimated annual CO2 emissions that deviate as much as ± 9% from an estimate derived using 30 years of data (Collins et al., 2018). This indicates that single-year modeling may underestimate or overestimate the availability of renewables relative to demand and therefore the need for balancing technologies. Other work showed how computed capacity mixes can differ depending on the assumed meteorological conditions (Tröndle et al., 2020). Inter-annual variability in hydrological flows can further affect the flexibility of hydro reservoirs (Korpaas et al., 2013). Tande et al. (2012) found that annual income for a project combining offshore wind and reservoir hydro varied by ± 5% across 30 years of weather data. Though we find limited effects of a sensitivity test of our results to a 10% reduction in water inflows (see Supplementary Material section 1.5), future work is necessary to explore how the value of hydro reservoirs would be impacted by these uncertainties.

Another limitation of this work is that we do not explore impacts of climate change on weather-dependent variables. Craig et al. (2020) found that climate change will increase the need for balancing technologies. While this could mean an increased value of hydro reservoirs, their ability to serve as a balancing resource may also be impacted by climate change. Projections by IPCC (2014) show increases in temperature and precipitation over high-latitude regions of North America by 2100, alongside decreases in spring snow cover. A large number of studies have explored the likely regional impacts on Quebec's watersheds (Velázquez et al., 2013; Rouhani and Leconte, 2018, e.g.). Broadly speaking the evidence suggests increased runoff. However, there are significant uncertainties surrounding inferences on regional effects, on which further research is needed. Moreover, there are other hydrological dimensions besides total runoff, such as the timing of the spring peak. The implications of these changing patterns for operation of the hydro facilities is another subject in need of research (Schaefli, 2015).

Future work could further explore interactions between hydro reservoirs and competing flexibility solutions such as long-term storage technologies or power-to-X solutions such as hydrogen. Another area for additional research is how renewable siting constraints may impact planning of low-carbon power systems and the role of hydro reservoirs.

CRediT authorship contribution statement

Emil G. Dimanchev: Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Writing – review & editing, Visualization, Validation. **Joshua L. Hodge:** Conceptualization, Writing – original draft, Writing – review & editing, Supervision, Project administration. **John E. Parsons:** Conceptualization, Methodology, Writing – original draft, Writing – review & editing, Supervision, Validation.

Declaration of competing interest

This research was funded by MIT's Center for Energy and Environmental Policy Research (CEEPR), which is supported in part by a consortium of industry and government Associates. The list is available at: http://ceepr.mit.edu/support/associates.

Acknowledgements

Two anonymous referees provided helpful comments, which helped improve this work. Hydro Quebec provided helpful information cited in the paper. The authors also thank Patrick R. Brown, National Renewable Energy Laboratory, for assistance with renewable availability data and Caitlin Murphy, National Renewable Energy Laboratory, for helpful comments regarding electricity consumption data. This research was funded by MIT's Center for Energy and Environmental Policy Research (CEEPR), which is supported in part by a consortium of industry and government Associates. The list is available at: http://ceepr.mit.edu/support/associates.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2021.112369.

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