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The role of cross-border electricity trade in transition to a low-carbon economy in the Northeastern U.S

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ABSTRACT

Canadian hydropower resources offer a potentially attractive option for meeting decarbonization targets in the US Northeast region, where there are ambitious climate goals and nearby hydro resources in Quebec. Existing transmission capacity is, however, a limiting factor in expanding hydropower imports to the region. To examine the value of expanding transmission capacity from Quebec to the Northeast, we employ an integrated top-down bottom-up modeling framework (USREP-EleMod). This research was part of an Energy Modeling Forum effort, EMF34, with a goal of better characterizing linkages in energy markets across North America. The scenarios we examine exogenously expand transmission capacity by 10, 30, and 50% above existing capacity into the US Northeast (New York/New England), finding the value to the economy of these expansions ranging from \$.38-\$.49 per kWh imported into New York, and \$.30-\$.33 per kWh imported into New England by 2050. The scenarios include economy-wide emissions goals these states have set for themselves. The carbon limits we imposed raise fuel prices more than electricity prices and as a result we found greater electrification in the US Northeast region from 2030 onward, a result that one would not see using just an electricity sector model, demonstrating a main hypothesis of EMF34, that models that looked at more integration across energy markets would give deeper insight than more narrowly focused models.

1. Introduction

The US Northeast has adopted particularly ambitious climate goals, seeking to reduce economy-wide emissions by 80 to 100% by 2050 and along with them specific targets for expanding intermittent renewables. One controversial part of meeting these targets is an increase in hydropower imports from neighboring Quebec. The appeal of hydropower is that it is dispatchable and hence could complement intermittent renewable energy resources by filling in when production from wind and solar in the region is low. Controversy arises because small communities and environmentally rich areas along the paths of proposed power lines, see these as eyesores and a disruption to natural areas, with little benefit to the affected communities. Thus, it is important to characterize the potential benefits, if any, of transmission expansion between Quebec and the US Northeast.

This study was conducted as part of EMF34, which had a focus on North American energy trade and integration (Huntington et al., 2020; Siddiqui et al., 2020). The primary hypothesis of the study was that analyses that represented better the integration, or potential for integration, across the US, Canada, and Mexico, and across energy markets, would lead to different and representative results than more narrowly focused studies on a single region, or market. As part of EMF34, there was also a specific focus on the role of cross-border energy-trade infrastructure development, and its effects on future energy trade. The potential for expanding transmission capacity from Quebec to the US Northeast as these states attempt to meet aggressive climate targets fits well within the broad hypotheses on which EMF34 was founded.

Following the EMF34 study design, we exogenously expand transmission capacity by 10, 30, and 50% starting in 2026 from our reference with existing capacity. We have 2 primary hypotheses in the study: (1) Increased hydro capacity will have economic benefits to the broader regional economy; (2) despite higher electricity prices from decarbonization of production of electricity, the economy will see greater electrification as the broader economy reduces its use of fossil fuels. To undertake this study, we develop an integrated top-down bottom-up modeling framework (USREP-EleMod) that combines a multi-region,

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Table 1
State GHG emissions target initiatives in the US northeast region.

States	Targets	Sources
New York	100% from 1990 levels by 2050 with the interim goal of 40% below 1990 levels by 2030	The New York State Senate (2019)
Connecticut	10% below 1990 levels by 2020 and 80% below 2001 levels by 2050	State of Connecticut (2008)
Rhode Island	10% below 1990 levels by 2020, 45% below 1990 levels by 2035, and 80% below 1990 levels by 2050	State of Rhode Island (2014)
Massachusetts	25% below 1990 levels by 2020 and 80% below 1990 levels by 2050	Commonwealth of Massachusetts (2008)
Vermont	40% below 1990 levels by 2030 and 80 to 90% below 1990 levels by 2050	State of Vermont (2016)
New Hampshire	80% below 1990 levels by 2050 and a short-term target of 20% below 1990 levels by 2025. Previously in 2001, New Hampshire had enacted a target of 1990 levels by 2010, 10% below 1990 levels by 2020, and 75–85% below 2001 levels in the long term.	State of New Hampshire (2009)
Maine	25% below 1990 levels by 2020 and 80% below 1990 levels by 2050	State of Maine (2019)

multi-sector, dynamic general equilibrium model of the US economy with a regional, chronological, hourly-dispatch and capacity expansion electricity model. The hourly electricity model is essential to comparing the costs of development of capacity within the region to that of increased hydro imports. The economy-wide model is essential to assessing the impact on demand for electricity, with consequent impacts on capacity expansion and/or more imports.

The rest of the paper starts with a brief summary of the climate and energy policy planning in the US Northeast in Section 2. Section 3 presents the modeling framework used for the analysis. Scenarios are described in Section 4 followed by results discussion in Section 5. We conclude in Section 6.

2. Climate and energy policy planning in the US Northeast

Most Northeastern states plan to reduce CO_2 emissions by 80% below 1990 levels by 2050, with New York aiming for a 100% reduction (Table 1). To achieve these economy-wide reductions, a goal throughout the region is a significant expansion of wind and solar power. Wind and solar costs have been declining making these sources very attractive, but as the share of power generation by intermittent renewables expand, there can be a poor match between hourly and seasonal patterns of supply and demand that may result in spillages during periods of oversupply, requiring costly back-up, storage, or extra generation capacity. Even though wind and solar power may be low-cost in terms of levelized cost of production (LCOE), the intermittent nature of these resources can raise costs of meeting carbon reduction targets at higher penetration levels because of the need to maintain large operational reserves and additional flexibility required to supply power when they are not available, additional transmission for integrating resources that are usually located away for load centers, among others (see for example Tapia-Ahumada et al., 2019; Greenstone et al., 2019).

An alternative to these costly approaches for addressing intermittency is to use flexible hydro capacity to fill in during periods when demand exceeds intermittent renewable supply. Hydro capacity associated with large reservoirs, as in the case of Quebec, could be such an option, although for the hydro capacity to be useful there must be sufficient transmission capacity to engage the available hydropower.

As Fig. 1 shows, historically electricity imports from Canada to the Northeastern regions have been increasing over the past years, most of them from large hydroelectricity projects. In 2014 for example, 1.6% of the electricity sales in the US came from Canada, with New England and

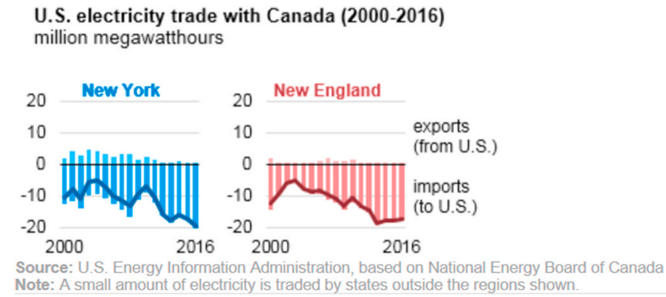

Fig. 1. Electricity trade between the northeast US and Canada. Source: EIA (2017).

New York accounting for 60% of the total imports which represented 12% and 16% of the region's retail sales of electricity according to EIA (2017).

The notion of bringing additional Canadian hydropower to US power markets has been always attractive. It appears as an option for helping to meet strict Renewable Portfolio Standard (RPS) requirements, a substitute for planned retirements of nuclear plants or other fossil-intensive technologies, a complement to natural gas (EIA, 2017), and more recently an alternative to meet the proposed economy-wide CO_2 emission targets.

According to DOE (2018), several transmission projects that would connect Canada to the US Northeast and Midwest regions are at various planning stages. Five separate projects (Fig. 2) have received a DOE presidential permit in recent years. While the DOE permit is necessary for construction, operation, and interconnection of electric facilities crossing the U.S. border it is not sufficient as additional authorizations from other federal and state agencies are also required before starting construction.

Hydropower from Canada has potential benefits of diversifying the electricity matrix of New York and New England states, while meeting long-term climate goals. As noted by Dimanchev et al. (2020), extending cross-border links could allow Quebec's hydropower reservoirs provide grid balancing to the Northeaster US and the storage potential in Canada could enable more solar and wind deployment in both US regions. Bouffard et al. (2018) explore the value of regional integration in decarbonizing the Northeast region including the Canadian provinces of Ontario, Québec and the Maritimes in addition to New York and New England. They find that a regional coordinated integration brings economic gains to the power sector because of the greater ability to optimize renewable production and by allowing hydropower to balance all sub-regions' demand.

However, power import from Canada is not free of challenges. Various transmission proposals have faced opposition from communities in their path because the lines are seen as mostly benefiting electricity consumers in large metropolitan areas, at the expense of environmental and recreation resources in these communities. There are also concerns regarding methane emissions from large hydro reservoirs, a potent GHG, and their environmental implications. Some have expressed concerns in that Hydro-Québec for example could supply domestic consumption with imported fossil fuel generation while increasing exports to New England,[1] or purchase energy from other markets during hours of low electricity prices while storing water in the reservoirs to sell power at later periods of high prices to New England markets (Energyzt Advisors, 2018). Finally, the renewable industry in the Northeast can see Canadian hydroelectricity imports as a competitive threat.

[1] See for example "Effort to Trade Gas for Hydropower in Northeast Meets Resistance" by E&E News on May 22, 2019 https://www.scientificamerican.com/article/effort-to-trade-gas-for-hydropower-in-northeast-meets-resistance/.

Transmission project	Developer	Proposed route	Proposed capacity (MW)	Presidential permit issuance date
Champlain Hudson Power Express	Transmission Developers Inc.	Canada-U.S. border at Lake Champlain to New York City (333 miles)	1,000	10/06/2014
Great Northern Transmission Line	Minnesota Power	Canada-U.S. border at Roseau County, MN-Grand Rapids, MN (224 miles)	883	11/15/2016
New England Clean Power Link	Transmission Developers Inc.	Canada-U.S. border at Alburgh, VT, to Ludlow, VT (154 miles)	1,000	12/05/2016
ITC Lake Erie Connector	ITC Lake Erie Connector, LLC	Canada-U.S. border at Haldimand County, Ontario, to Erie County, PA (72 miles)	1,000	01/12/2017
Northern Pass Transmission	Eversource Energy	Canada-U.S. border near Pittsburg, NH, to Franklin, NH (192 miles)	1,090	11/16/2017

Fig. 2. Proposed transmission projects crossing Canada-US border with presidential permits. Source: DOE (2018).

3. An integrated approach[2]

To evaluate the role of imports of Canadian hydropower to the US Northeast region in transition to a low-carbon economy, it is important to capture the impact of hydro power imports on the electricity sector where renewable energy sources play an ever-increasing role. Equally important is to keep the non-electric sectors interacting consistently with the bottom-up electricity system for an economy-wide assessment of low-carbon policies. To this end, we employ an integrated model that combines two paradigms used by policy and decision makers, namely top-down (TD) and bottom-up (BU) approaches that combines a multi-region multi-sector dynamic general equilibrium model of the US economy with a chronological dispatch and capacity expansion electricity model. A dynamic general equilibrium model that portrays an economy with all sectors interrelated through markets where equilibrium prices and quantities are determined simultaneously provides a consistent framework that captures direct and indirect impacts. A capacity expansion and operational model with profiles on hourly demand and hourly supply of wind and solar by geographic region can provide a reasonable spatiotemporal representation of the electricity system. Thus, this approach incorporates interactions among different aspects of the economy, captures high-resolution spatiotemporal evolution of the electricity sector and generates a set of internally consistent solutions, serving as an analytical tool to reliably guide future operations, investments, and policies decisions.

3.1. The top-down model

The top-down component of the integrated model is the MIT US Regional Energy Policy (USREP) model, a multi-region multi-sector energy-economic general equilibrium model of the US economy (Rausch et al., 2010, 2011, 2014, 2015; Yuan et al., 2017, 2019a, 2019b). USREP is built on a state-level economic dataset of the US economy, called IMPLAN (IMPLAN, 2008) covering all transactions among businesses, households, and government agents for the base year in 2006. For the purpose of energy and environmental policy study, we improve the characterization of energy markets in the input-output dataset prepared by IMPLAN by replacing its energy accounts with physical energy quantities and energy prices from Energy Information Administration State Energy Data System (EIA-SEDS, 2009) for the same benchmark year 2006. The final dataset is rebalanced using constrained least-squares optimization techniques to produce a consistent representation of the economy.

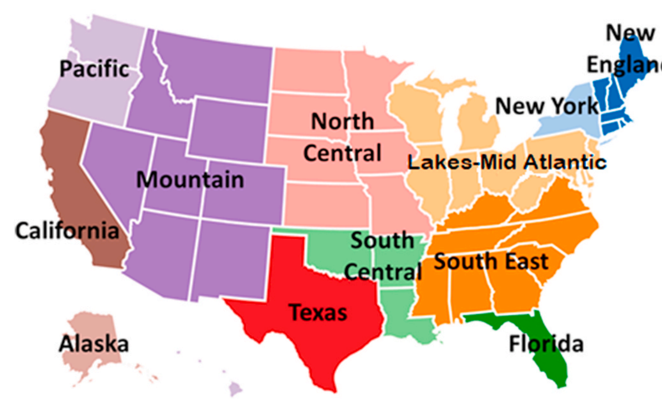

Fig. 3. USREP regions.

The standard version of USREP aggregates 509 commodities in the IMPLAN dataset to five energy sectors and six non-energy sectors. The energy sectors include coal (COL), natural gas (GAS), crude oil (CRU), refined oil (OIL) and electricity (ELE). The non-energy sectors include energy-intensive industries (EIS), agriculture (AGR), commercial transportation (TRN), personal transportation (HHTRN), services (SRV) and all other goods (OTH). In each sector, output is produced using inputs of labor, capital, energy and intermediate material goods. Primary energy production sectors (crude oil, shale oil, coal, natural gas) use depletable natural resources (crude oil, coal, and natural gas). The model also includes primary energy production sectors that use renewable, non-depletable resources (wind and biomass). Agriculture and biomass production use land. Production is modeled assuming constant-elasticity-of-substitution (CES) functions that is constant returns to scale. Firms operate in perfectly competitive markets and sell their products at a price equal to marginal costs. In each region, a single government entity approximates government activities at all levels - federal, state, and local. Government consumption is paid for with income from tax revenue net of any transfers to households.

USREP represents the US by twelve geographic regions (see Fig. 3), namely Alaska (AK), California (CA), Florida (FL), New York (NY), Texas (TX), New England (NENGL), South East (SEAST), Lakes-Mid Atlantic (LMATL), South Central (SCENT), North Central (NCENT), Mountain (MOUNT), Pacific (PACIF) to account for variations in energy consumption and production across the country. The regions correspond

[2] A large part of the description of USREP-EleMod integration approach is drawn from Yuan, Tapia-Ahumada, Montgomery (2019b).

roughly to electricity power pool regions in which electricity produced in that region can serve any household or industry in that region. In each region, we model nine households that differ in the income level as well as the composition of income sources from wages income and rents from the ownership of capital and natural resources. Households of different income levels consume different bundles of goods.

The investment sector in USREP is specified based on the IMPLAN dataset to account for investment demand by private and public entities. The investment sector produces an aggregate investment good equal to the level of savings determined by the representative agent's utility function. The accumulation of capital is calculated as investment net of depreciation according to the standard perpetual inventory assumption. USREP is a recursive-dynamic model, and hence savings and investment decisions are based on current period variables. Capital is assumed fungible across regions and labor is assumed immobile across regions.

To represent historical changes in energy and economic structure, the model is calibrated up to 2016 based on information from Energy Information Administration (EIA)'s Annual Energy Outlooks (AEO). To establish a reference case consistent with official projections, we calibrate the model to match GDP growth through 2050 in EIA's AEO2018 Reference case (EIA, 2018) by updating regional labor productivity growth rates. Policies affecting the US energy system and end-use energy efficiency, such as the regional RPS for electric power generation and national CAFE standards (and separate CAFE standards for California) for vehicle transportation are represented in our reference case to reflect regulations currently on the books. Detailed description of USREP is available in Yuan et al. (2019a).

3.2. The bottom-up model

The bottom-up component of the integrated model is a capacity expansion and economic dispatch model intended to capture the long-term adaptation of a system to the penetration of intermittent renewable generation in the US (Tapia-Ahumada, 2021; Tapia-Ahumada et al., 2014, 2015). There are a wide range of electricity sector models with different levels of detail, covering timeframes that range from milliseconds to years or decades. Capacity planning considers investment in power plants with lifetimes of 20 to 30 years or more, and therefore focuses on years to decades (Fig. 4). On the other end are concerns about stability of the grid, and network flows at minutes, seconds, and milliseconds.

To understand future low carbon pathways within electric systems, it is necessary to look at periods of years to decades, with a major focus on what types of electricity generation will be needed to meet low carbon constraints. Intermittent renewables make these analyses more difficult as the decision to invest in wind, solar, nuclear or gas depends on the differential costs of dealing with the great variability of net demand brought about by the intermittency and variability of renewables.

The electric power system model (EleMod) is formulated at the same regional level as in USREP. Following the approach proposed by Perez-Arriaga and Meseguer (1997), EleMod determines the most cost-effective electric generation expansion and operation subject to technical and policy constraints, such as environmental limitations, short-term operating reserves and long-term adequacy requirements in order to maintain acceptable reliability levels. The model incorporates hourly regional load demands, hourly regional wind and solar profiles estimates, resource estimates for wind and solar taking into consideration geospatial limitations, and several technology categories such as utility-scale storage, fossil-fuel based technologies including gas-fired and coal-fired plants, and nuclear plants. In the model, existing regional transmission interties are approximated and electricity trade among regions is possible, except among the Texas, Western, and Eastern interconnects.

EleMod is formulated as a linear programming (LP) problem, minimizing the total cost of electricity generation for all regions r considering capital investment costs C_r^{fixCap}, fixed O&M C_r^{fixOM}, variable O&M C_r^{varOM}, and other operational costs such as fuel-related costs $C_r^{varFuel}$, CO_2 emission costs C_r^{varCO2}, start-up costs C_r^{StUp}, and non-serve energy cost C_r^{NSE} (Equation (1)).

$$Min\,Cost = \sum_r \left[\left(C_r^{fixCap} + C_r^{fixOM} \right) + \left(C_r^{varOM} + C_r^{varFuel} + C_r^{varCO2} \right) + C_r^{StUp} + C_r^{NSE} \right] \tag{1}$$

EleMod is deterministic with a recursive-dynamic structure. Optimal solutions are computed sequentially for every two-year period, adding new capacity as needed to meet growing demand, replace retired units, or meet new policy constraints. It includes three decision timeframes defined as capacity expansion planning, operational commitment planning and operational hourly dispatch decisions.

As Equation (2) show, the model relies on annualized costs of producing electricity in a region r, considering annualized investment costs for each conventional fossil-based technologies n $\left(c_{r,\,n}^{fixInv}\right)$, wind class c $\left(c_{r,c}^{fixInv\_wind}\right)$ and solar renewables $\left(c_r^{fixInv\_solar}\right)$, and pumped hydro storage $\left(c_r^{fixInv\_phs}\right)$. Accordingly, main decisions variables include not only operational decisions such as daily connected power and hourly production, but also generation investments to install for fossil fuel technologies $(K_{r,n})$, wind and solar $(K_{r,c}^{wind}$, $K_r^{solar})$ and pumped hydro storage (K_r^{phs}).

$$C_r^{fixCap} = \sum_n K_{r,n} \cdot c_{r,\,n}^{fixInv} + \sum_c K_{r,c}^{wind} \cdot c_{r,c}^{fixInv_{wind}} + K_r^{solar} \cdot c_r^{fixInv_{solar}} + K_r^{phs} \cdot c_r^{fixInv\_phs} \forall r \tag{2}$$

In the particular case of renewables, their hourly profile estimates are incorporated based on historical and/or numerical weather prediction models time series. Wind hourly profiles are taken from National Renewable Energy Laboratory (NREL) data and aggregated at the regional level of the model. These are far less variable than a single site as they integrate over fairly large regions. However, there are still large swings in wind resource availability hour-by-hour, from near full capacity to little or no availability, and also monthly and seasonal variations among regions. Solar hourly profiles are simulated using NREL's System Advisor Model at state level, for various latitude locations and then aggregated at regional level. In general, solar profiles show the strong diurnal pattern of availability with no resource during night time, and higher availability in summer months than in winter, with some day-to-day variation reflecting cloudiness and regional time zone differences. Both wind and solar generation can be curtailed depending on technical constraints and system's oversupply conditions.

For hydro generation, the model currently does not endogenously optimize existing hydro power dispatch. We represent variation in their profiles at regional scale to approximate the electricity production coming from non-intermittent renewable resources. Based on historical records using USGS data (UCS, 2012) as described in Boehlert et al. (2016), we established wet, medium, and dry annual hydro supply conditions and for this paper we simulate a medium scenario.

Fossil fuel-based generation options include 12 conventional technologies. Their representation requires simplified cost and performance characteristics, minimum loading requirement, availability factors, forced outage rates, and heat rates for thermal plants. As noted earlier, costs include fixed and variable O&M, capital, start-up, and fuel. There is also a capacity reserve requirement to ensure long-term reliability of the

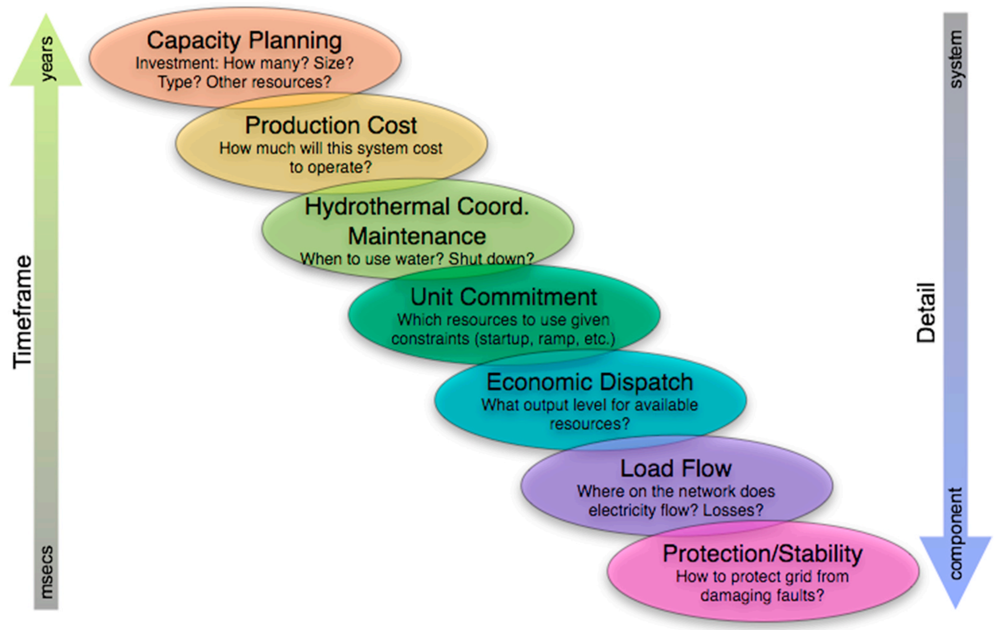

Fig. 4. Hierarchical decision-making process in power systems (Palmintier, 2013).

system to unexpected peaks in demand, assumed to be between 10 and 18% depending on the region. Existing installed capacity per technology is represented in the base year 2016 as the total capacity for each technology in each region based on EIA form 860 and the EIA's AEO Reference Case.[3,4] We have generally assumed that technology costs, in the reference case, are those used by the EIA's AEO2018 Reference case (EIA, 2018), except for wind and solar where we have assumed annualized capital cost and fixed O&M cost continue to decline at 2% and 3% per year for wind and solar, respectively.[5]

Finally, we assume a prescribed annual demand path for electricity and fuel prices projections based on the EIA's AEO2018 Reference case (EIA, 2018). The most relevant ones being gas, coal, and nuclear fuel costs which rise slowly over time. See Appendix A for details about technology costs, and operational parameters.

3.3. The top-down bottom-up integration

The method to integrate the top-down (TD) general equilibrium model and the bottom-up (BU) chronological model is based on the decomposition algorithm laid out in Böhringer and Rutherford (2009). The first implementation of the approach in a large-scale computable general equilibrium model of the US economy is documented in Tuladhar et al. (2009). The description of the USREP-EleMod integration approach to achieving convergence in the electricity market is provided in Yuan, Tapia-Ahumada and Montgomery (2019b). To analyze an economy-wide carbon policy, we extend the approach to achieving convergence in the emissions market and provide detailed steps in this section.

3.3.1. Electricity market

In USREP, the electricity sector is exogenized by converting a CES production function to a linear input-output representation parameterized based on electricity generation and input demand simulated by EleMod. In EleMod, a quadratic programming (QP) problem is formulated to incorporate demand response from USREP. The quadratic formulation maximizes the total surplus of the electricity market, i.e. consumer surplus and producer surplus taking into account overall costs of producing electricity by power suppliers, subject to system operational, security and policy constraints. In Equation (3), p_r^0 and d_r^0 denote a set of reference electricity price and demand in region r. ε_r^0 denotes demand elasticity. d_r and $Cost_r$ are regional electricity supply and total system cost determined by EleMod in response to a demand curve characterized by p_r^0, d_r^0, and ε_r^0.[6]

$$Max\ Welfare = \sum_r \left(p_r^0 \cdot d_r \cdot \left(1 - \frac{\left(d_r - 2 \cdot d_r^0\right)}{2 \cdot d_r^0 \cdot \varepsilon_r^0} \right) - Cost_r \right) \tag{3}$$

Iterations between the USREP and EleMod involve passing back and forth electricity supply, fuel demand and prices information until both models converge. Fig. 5 illustrates the iterative process and the information that each model needs to exchange in order to reach general equilibrium conditions.

For each year in the reference case, we feed the regional electricity supply and fuel prices based on EIA's AEO2018 Reference case projection (EIA, 2018) to EleMod which in turn determines generation by technology type, generation input demand (fuel demand, capacity investment, O&M costs) and electricity supply price comprised of generation cost, RPS compliance cost, cost of operating reserve and marginal reserve requirement. EleMod passes electricity supply, generation input demand and electricity supply price to USREP. While calibrating USREP to the electricity supply, electricity input demand as well as electricity supply price, we impose a zero-profit condition for the electricity sector

[3] See Form EIA-860 detailed data at https://www.eia.gov/electricity/data/eia860/.

[4] See EIA, 2018 Reference Case electricity and renewable fuel tables at https://www.eia.gov/outlooks/archive/aeo18/supplement/excel/sup_elec.xlsx.

[5] The basis for wind and solar costs decline are somewhat arbitrary, as the authors have tried to reflect expected declining costs for these two technologies and formulate a case where their costs is not an additional constraint on their future adoption.

[6] Böhringer and Rutherford (2009) provides detailed steps in deriving the welfare objective.

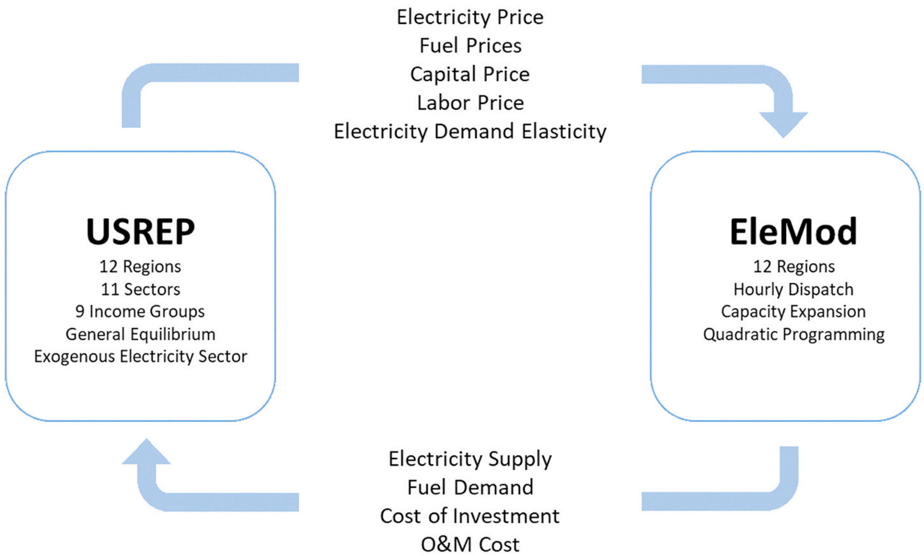

Fig. 5. Coupling the TD and BU models – Information Exchange.

by allocating the electricity sector profit/loss to household.[7] In such a sequence, we run the models in a two-year step to 2050 and achieve consistency between the models in electricity supply, generation input demand and electricity supply price.[8]

In the counterfactual scenario, the TD-BU model runs iteratively as illustrated in Fig. 5 To a new policy regime, EleMod responds with changes in electricity supply, generation input demand and electricity supply price as a result of maximizing the total surplus of the electricity market characterized by reference electricity supply, price, and demand elasticity. We pass the updated electricity supply and generation input demand to USREP which produces a general equilibrium response in prices to both the change in policy regime and the changes in electricity supply and generation input demand. We then pass the changes in prices of electricity demand, fuel supply, capital and labor supply to EleMod and update the reference electricity price, fuel prices, fixed O&M cost and variable O&M cost, respectively. In addition, we update the reference electricity supply in the quadratic objective function to be consistent with the reference electricity price. To speed up the convergence, we derive a local estimate of the electricity demand elasticity in USREP and update the elasticity parameter in the quadratic objective function in EleMod accordingly. The iteration between the TD and BU model continues until both models agree on electricity price. That is, the electricity supply price generated by EleMod and the electricity demand price generated by USREP converge.

Iteration between the models is important because demand for resources – fuels, capital, labor, and materials – in the electricity model must be communicated in a consistent way to the macro model to capture the market response given the limited supply of those resources in each time period. Likewise, the changes in prices must be communicated back to the electricity model to ensure consistency in economic dispatch decisions based on the updated generating technology costs. Given the different temporal resolution and databases of the two models, this is a nontrivial task.

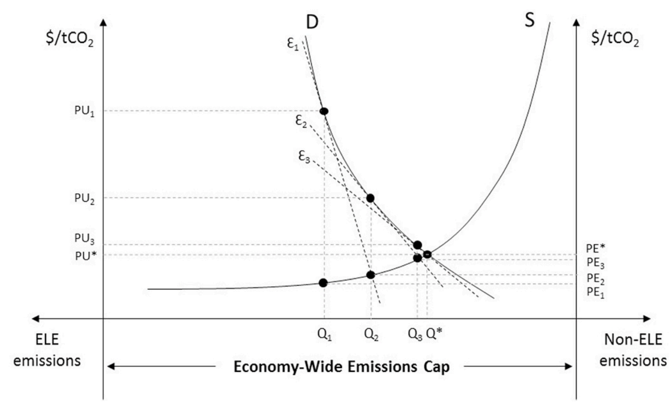

Fig. 6. Non-electricity sector emissions market.

3.3.2. Emissions market

For carbon policy evaluation, an economy-wide carbon constraint with emission trading between the electric and non-electric sectors requires convergence in endogenous carbon price determined by the TD and BU model. To achieve this, we build an economy-wide carbon market in EleMod as an instrument to implement an emissions trading scheme between the electricity and non-electricity sectors. In EleMod, to meet a fixed emission cap, each additional reduction of the electricity sectoral emissions is equivalent to each additional non-electricity sectoral emission supply therefore the non-electricity emissions supply curve corresponds to the marginal abatement cost curve of the electricity emissions. Given exogenous electricity sectoral emissions, USREP represents the non-electricity emissions demand that captures the marginal abatement cost of the non-electricity sectors. With the non-electricity emissions supply associated with marginal abatement cost of the electricity sector and the non-electricity emissions demand associated with marginal abatement cost of the non-electricity sectors, we construct a market for the non-electricity emissions where the supply is represented in EleMod and the demand is modeled in USREP. This market is built in EleMod where the QP objective is augmented to

[7] Lacking information on ownership of the electricity sector, we allocate electricity profit/loss to households in proportion to capital income. The alternative is to treat electricity profit/loss as a collective investment gain/loss that contributes to or draws from the regional investment fund. Different treatment of profit/loss has different welfare implication.

[8] EleMod is calibrated in the reference to EIA fuel prices, regionalized to represent regional differences. Fuel prices also vary by sector (industrial, residential, electric sector) and so for the fuel delivered to the electric sector we calibrate to electric sector prices. USREP has a single price for each fuel within a region. Once calibrated in the reference, we apply the percentage change in the USREP regional fuel price indices to the electricity-sector specific price in EleMod to maintain the prevailing variation in delivered prices to the electricity sector from that delivered to other sectors.

include demand response to non-electricity emissions.

The non-electricity emissions market is introduced to EleMod as an instrument to implement an economy-wide emissions trading scheme between the electricity and non-electricity sectors (see Fig. 6). D and S denote the demand and supply curve, respectively. In each iteration, the equilibrium non-electricity emissions, marginal abatement cost associated with the electricity and non-electricity sectors, and demand elasticities are denoted by E, PE, PU, and Ɛ, respectively, with an iteration subscript. Price and quantity denoted with an asterisk indicates a converged solution where PU* equals to PE* at the non-electricity emissions level Q*.

Fig. 6 illustrates an iterative process that involves passing the non-electricity emissions and carbon prices from USREP to EleMod, solving EleMod to establish an optimal level of the non-electricity emissions hence electricity emissions and pass the electricity emissions to USREP for another round of iteration until both USREP and EleMod agree on a set of endogenous carbon prices generated based on the marginal abatement supply curve of all sectors in the economy. The iterative process ends with convergence in carbon prices from USREP and EleMod. To speed up the carbon price convergence, we derive a local estimate of the non-electricity emission demand elasticity in USREP and update the elasticity parameter in the quadratic objective function in EleMod accordingly. The algorithm usually achieves good convergence within 6–7 iterations.

4. Scenarios

We develop a reference scenario that includes existing regional RPS policy and four counterfactual scenarios that all impose an economy-wide emissions policy for New York (NY) and New England (NENGL). Following EMF34 guidance, the four scenarios vary the level of transmission capacity between Canada and the US Northeast, including no further expansion of transmission line capacity and, starting in 2026, expansion of transmission by 10%, 30% and 50% relative to the existing capacity.[9]

(1) (**Ref**) USREP generates its own reference projection based on its resource supply and demand characterizations, and EleMod is calibrated to the EIA's AEO2018 Reference case projection (EIA, 2018). Our baseline includes existing RPS policies that is consistent with AEO assumption in their reference projection. RPS in New York is set to ramp up from 25% in 2021 to 41% by 2030 and remains at 41% out to 2050. RPS in New England is set to ramp up from 26% in 2021 to 40% by 2030 and further increase to 50% by 2050.

(2) (**Cap**) RPS levels in New York and New England are those assumed in the **Ref** case. A carbon emissions cap is implemented in New York and New England with emissions reduction targets relative to the 1990 levels (see Table 2 below).

(3) (**Cap_HiTran**) Both RPS levels and emission reduction targets in New York and New England remain at the level in the **Cap** scenario. Transmission line capacity expands by 10%, 30% and 50% starting in 2026 relative to the existing transmission capacity, with corresponding case labels (**Cap_HiTran10, Cap_HiTran30** and **Cap_HiTran50**) to differentiate the cases with different levels of transmission capacity.

Table 2
Emissions reduction targets below the 1990 levels.

	2020	2025	2030	2035	2040	2045	2050
NEW YORK	23%	31%	40%	51%	63%	74%	85%
NEW ENGLAND*	18%	28%	40%	50%	60%	70%	80%

Source: https://www.c2es.org/content/state-climate-policy.
*Authors' own calculation based on state-level reduction targets within the region.

These scenarios enable us to evaluate the role of hydro power imports from Canada along the state's decarbonization pathway, and the value of expanding the transmission capacity for more hydro power imports.

To characterize power trade with Canada, we took information from the Canadian Energy Regulator, specifically Monthly Electricity Trade Volumes and Monthly Electricity Trade Prices for year 2018 (CER, 2019)[10] and assumed constant values for monthly prices throughout the years. Lacking information on hourly trading prices, we assume uniform hourly prices within a month. For cross-border transmission line capacities between Quebec, Ontario, New York and New England regions, we used information provided by Bouffard et al. (2018).

For all scenarios, we assume existing nuclear capacity follow the retirement schedule stated in the EIA's AEO Reference case.[11] Wind, solar and hydro power are renewable energy sources counted towards the RPS requirement. Electricity imports from Canada to New York and New England are assumed 100% hydro power and also qualified as energy source to meeting RPS requirements. See Appendix A for other key assumptions used in the analysis.

In USREP, government consumption/expenditure is calibrated to EIA's AEO2018 Reference case projection (EIA, 2018) and held constant in the counterfactual scenarios. That is, any change in tax revenue under the counterfactual scenarios collected by government is offset by a lump sum transfer between the government and households. For example, a carbon tax may generally lead to a reduction in total tax revenue collected from personal income, corporate income, payroll taxes and sales taxes. We set aside a portion of the new carbon revenue from the carbon tax collected to replace the lost tax revenue such that government revenue is held equal to that in the reference case. In the version of the model under the study, we recycle the remaining portion of the carbon revenue in a form of lump-sum rebate to the household by the regional population weight in New York and New England.[12]

The version of the model used for the study treats households as the owner of the electricity sector, and allocates electricity rents to households in proportion to their capital income. Therefore, any impacts on electricity sector profit and loss is associated with a direct income effect on household consumption. Distributing it on the basis of capital income has further distributional implications, since lower income households derive proportionately less of their income from capital. USREP-EleMod runs in two-year time steps from 2006 to 2050. Within a model year, EleMod simulates in a 10-hour interval during the annual load over 8760 hours. Simulated years through 2016 are calibrated to historical data.

5. Results

The following sections present some of the main results from our

[9] In our scenarios, the expansion of transmission capacity is imposed exogenously, and any cost of such expansions is not included in our estimate of benefits of additional imports. Furthermore, our work focused on characterizing the economic benefits to the broader regional economy looking into the avoided welfare loss per kWh of additional electricity imported. We recognize this being a limitation of our modeling framework that will be addressed in future analyses.

[10] We assumed a conversion rate of 0.757646 for one Canadian Dollar to US Dollar, based on an annual average for year 2018.

[11] See nuclear capacity in EIA/AEO 2019 at https://www.eia.gov/outlooks/archive/aeo19/supplement/excel/sup_elec.xlsx.

[12] Alternative revenue recycling options are available in USREP to cut rate on taxes, such as payroll taxes, corporate income taxes or personal income taxes. The rate reduction is treated as an endogenous variable acting as a multiplier to adjust the current tax rates.

integrated model. We start with power trade with Canada and gains from transmission capacity expansion, followed by impacts on energy prices that play a vital role in driving energy conservation and electrification. We present carbon prices generated as a result of regional economy-wide carbon cap combined with different levels of transmission line capacity and provide the sectoral abatement in response to the carbon cost. Impacts on the electricity sector are discussed with a focus on generation profile.

5.1. Trade with Canada

Fig. 7 shows the electricity imports from Canada by New York and New England for the **Ref**, **Cap** and **Cap_HiTran** scenarios. As part of the model simulation, we benchmarked the reference case to the current Canadian monthly trade prices and volumes, as discussed in Section 4, and restricted trade to those volumes and prices for the full simulation period. The volume constraint was relaxed when imposing a carbon emissions cap and with transmission capacity expansion. Hence in both regions, we observe that the level of imports stays constant in the **Ref** scenarios, increases in the **Cap** scenario, and increases further when the transmission capacity is expanded. These increases in Canadian imports indicate that the Northeast benefits from the trade from Canada in all policy scenarios and the more transmission the more cross-border imports into the region.

Although not shown in the figures, the model represents regional interties that connect New York with New England, and LMATL with New York. The power trade flows normally one-way from New York to New England, and from LMATL to New York. When emissions caps are in place, LMATL sends more power to New York, which in turn also sends more power to New England to meet its policy goals. When additional transmission from Canada is available, New England relies less on New York and more on hydro imports.

We note that both regions fully utilize transmission capacity in all scenarios most of the years on our assumption that Canada has sufficient power to supply this level of demand in the New York/New England region.[13] The power trade with Canada is characterized by prices (from Canada to US) ranging from \$25/MWh in June to \$49/MWh in January, and prices (from US to Canada) ranging from \$22/MWh in March to \$93/MWh in January based on monthly variations of year 2018. One possible value of hydro-based Canadian imports is that they would serve as a back-up to intermittent renewables but given their relatively low cost we found that they crowd out, rather than complement the expansion of other renewables.

The exception to full capacity utilization of transmission occurs toward the end of the 2050 horizon. Beginning around 2040, imports into New England from Canada decrease, with around 8%–9% less than full utilization by 2050. In New England, storage (modeled as pumped hydro) reached the imposed resource limit by 2040 and until that year this technology was being used to provide flexibility to wind and solar, while imports from Canada remain at full transmission capacity. After year 2040, given the lack of additional storage for additional wind (solar also reached its resource limit in the region), the system uses hydro from Canada to provide that additional flexibility. Fig. 8 illustrates this situation in terms of annual generation for the **Cap_HiTran50** scenario, where New England hydro imports from Canada fall off slightly in 2050 with continued deployment of wind and solar, as opposed to New York where imports remain at full transmission capacity."

5.2. Economic benefits from hydro imports

To compare the economic benefits from hydro imports, we use welfare measured by equivalent variation. Under the **Cap** scenario, the Northeast experiences welfare losses of about 0.3% relative to the **Ref** scenario by 2030. The loss increases to just under 1% by 2040 and to around 1.6% by 2050. With more power imports from Canada under the **Cap_HiTran** scenarios, the avoided welfare loss could be as high as 0.05–0.2 percentage point depending on the level of transmission capacity expansion. These would appear to be measurable gains in avoided welfare loss. Since Canadian imports of electricity are relatively small compared to overall electricity consumption in the region, more relevant are the benefits of imports relative to the amount of electricity imported. To see that result, we take the avoided welfare losses in 2018 dollars and divide by the additional electricity imports. This allows us to plot these benefits in terms of dollars per kWh. We plot the benefits of all **Cap_HiTran** scenarios relative to the **Cap** scenario (see Fig. 9). We find in general larger benefits from every kWh of hydro import over time, suggesting increasing value of Canadian hydro power to the New York/New England region. The benefits are generally larger in New York than in New England, especially in the out years. The avoided welfare losses in New York in 2050 range from \$1.2 to \$4.4 billion. The benefits range from \$0.38/kWh with 50% transmission capacity expansion (**Cap_HiTran50)** to \$0.49 with 10% transmission capacity expansion **(Cap_HiTran10)** in New York by 2050, several times the current cost of the electricity itself. Benefits in New England in 2050 are smaller ranging from \$0.30/kWh to \$0.33/kWh in 2050. With the continued ability of New England to expand renewables, and their continued drop in cost, the benefits of Canadian imports relative to their avoided welfare losses are less than in the case of New York.

For New York, an inflection point around 2042 reflects a price effect of increased hydro imports on the in-state electricity supply, as discussed in Section 5.3. Starting in 2042, the price effect becomes substantial as hydro imports play a more significant role in lowering the cost of RPS compliance. However, the benefits decline as hydro imports increase because higher load demand as a result of a lower electricity price drives up power system cost, somewhat eroding the gains.

Changes in power system costs, including capital investment, fixed and variable O&M, fuel and other operational costs, is primary driver of the welfare results. Lower power system cost in the **Cap_HiTran** scenarios result in lower investment requirements in the power sector, allowing for more investment in other sectors that result in higher levels of production, consumption and greater welfare. Lower operating costs for power generation also allow for more consumption of other goods, and greater welfare. Second, the electricity sector profit/loss that directly affects the income as we treat the households as the owner of the electricity sector.

5.3. Cost of power generation

The carbon policy adds a carbon price on fuel used in electricity generation, leading to higher cost of generation. Fig. 10 (top) shows that in the **Cap** scenario the cost of generation, relative to the **Ref** scenario, rises by around 53% in 2030 and 86% by 2050 in New England and by around 50% in 2030 and over 100% by 2050 in New York. In the **Cap_HiTran** scenarios, the cost of generation decreases because more imports from Canada displace generation in the New York and New England. Compared to the **Cap** scenario, the cost of generation in the **Cap_HiTran** scenarios is reduced up to 1.1% in New York and 0.4% in New England by 2040. By 2050, the reduction in cost of generation grows up to 1.9% in New York and 3.8% in New England. Although the cost reductions are relatively small, they still reflect the contribution that imports from Canada make to the total amount of electricity which grow as more transmission capacity becomes available.

The electricity supply price is driven by the cost of generation, RPS compliance, and operating reserve and marginal reserve requirements. As the change in the cost of operating reserves and reliability reserves requirement across scenarios is small, the change in electricity supply price is driven mostly by the change in cost of generation in the case of New England and generation and RPS compliance costs in the case of

[13] The model does not evaluate if these Canadian exports are incremental supply or if it is sourced by reducing Canadian supply.

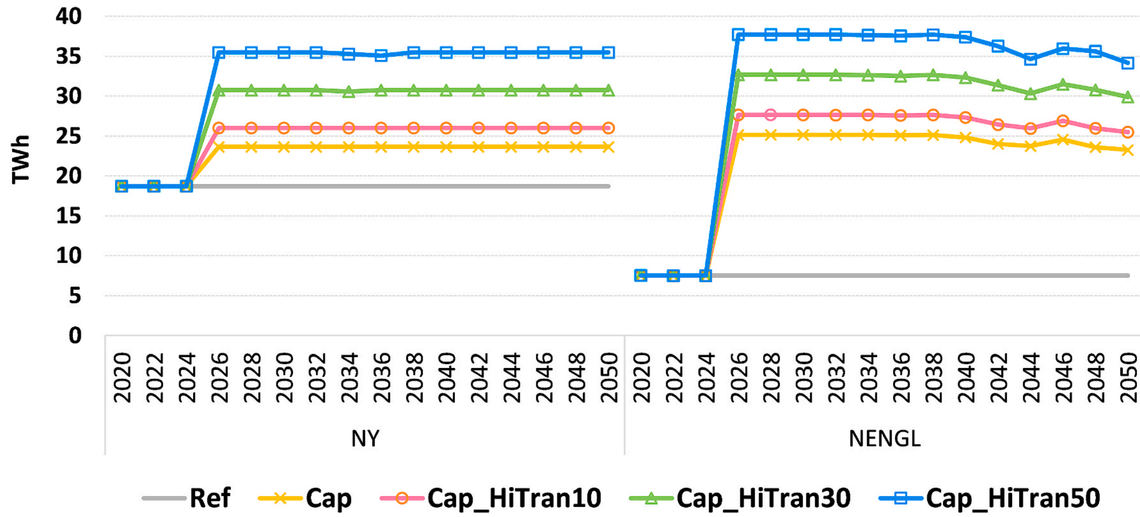

Fig. 7. Electricity imports from Canada by New York and new england [TWh].

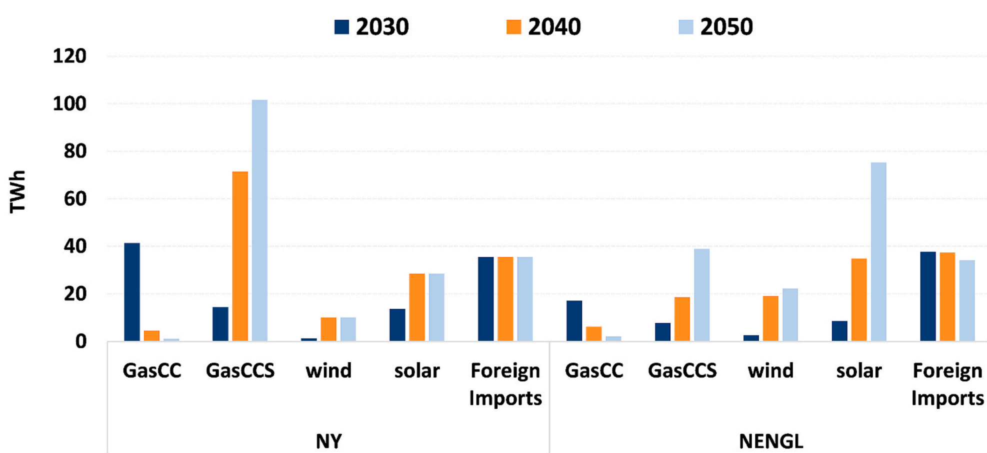

Fig. 8. Electricity generation for selected technologies and hydro imports from Canada in New York and new england under the **Cap_HiTran50** scenario [TWh].

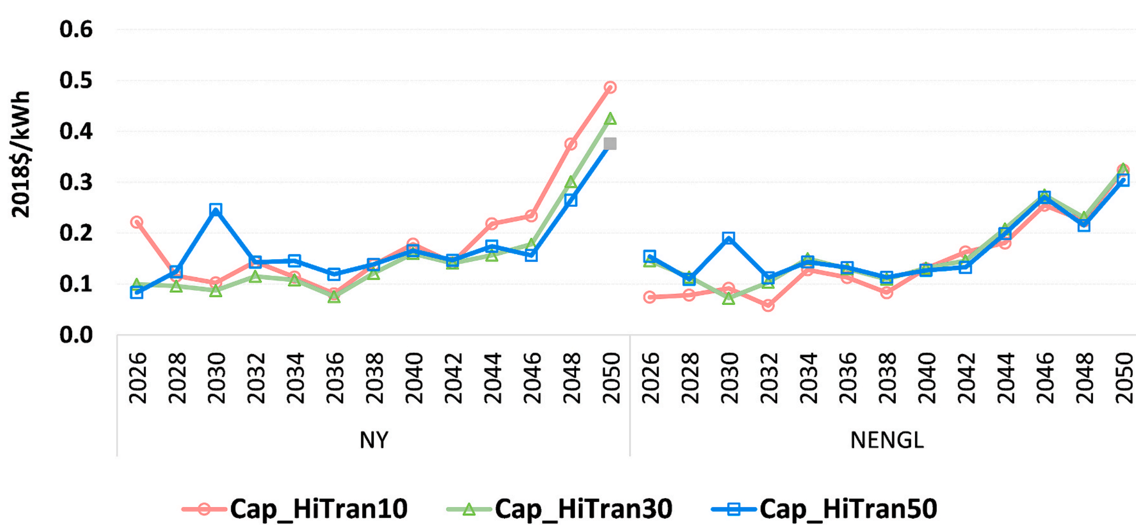

Fig. 9. Consumption Gain per kWh Increase in Hydro Power Import from Canada in New York and New England [2018$/kWh].

New York (see bottom of Fig. 10). In the **Cap** scenario, electricity supply price increases relative to the **Ref** scenario by 25% in New York and 26% in New England by 2030, by 48% in New Yok and 38% in New England by 2040, and by 233% in New York and 72% in New England by 2050. Compared to the **Cap** scenario, the electricity supply price in the **Cap_HiTran** scenarios decreases by up to 6.4% in New York and 0.1% in

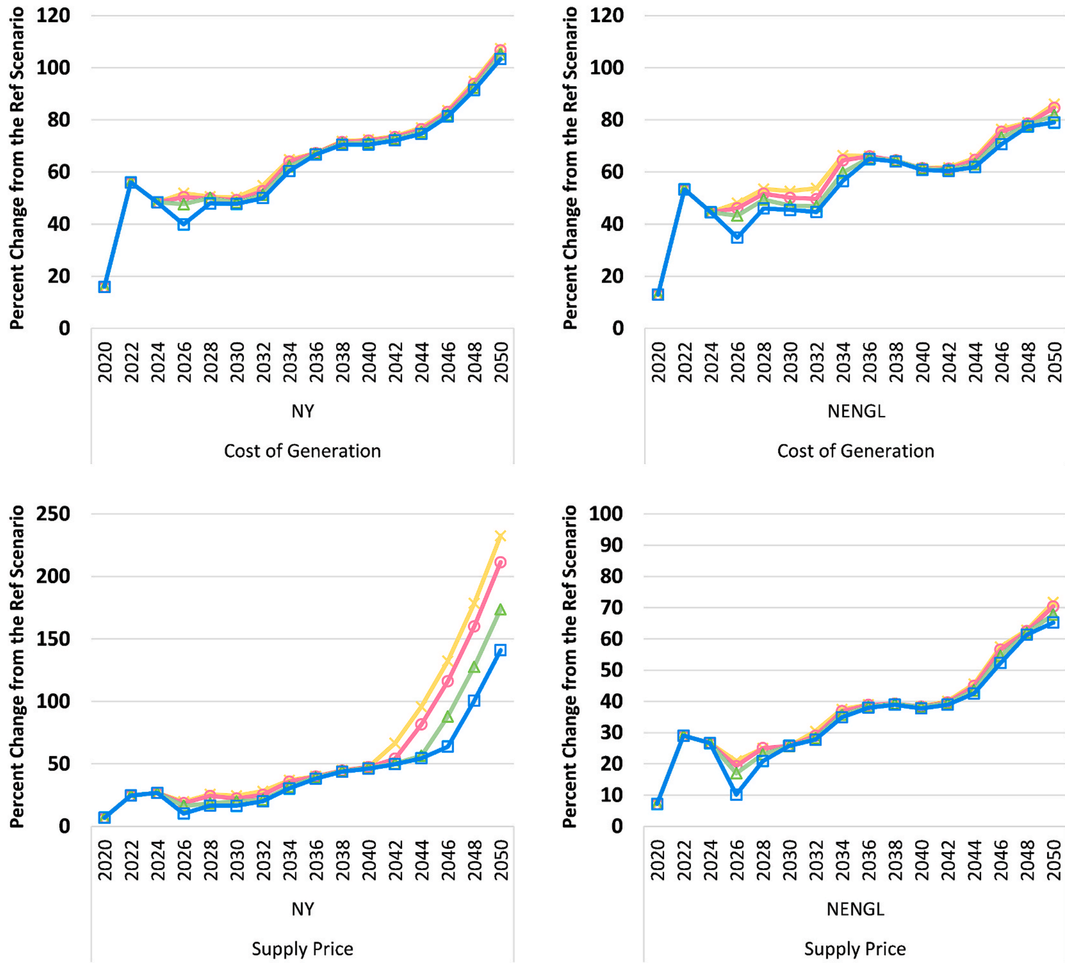

Fig. 10. Electricity Supply Prices, Percent Change in the Cost of Generation (top panel), and Percent Change in Electricity Supply Prices (bottom panel) in New York and New England.

Table 3
Delivered energy prices [percent change from the **ref** scenario].

			COAL	GAS	OIL	ELECTRICITY
NEW YORK	**2030**	Cap	850	35	33	16
		Cap_HiTran10	855	36	33	14
		Cap_HiTran30	927	38	37	15
		Cap_HiTran50	947	39	37	13
	2040	Cap	2233	103	97	29
		Cap_HiTran10	2230	102	97	28
		Cap_HiTran30	2227	102	97	28
		Cap_HiTran50	2223	101	97	28
	2050	Cap	4970	266	197	131
		Cap_HiTran10	4846	259	192	119
		Cap_HiTran30	4616	248	181	99
		Cap_HiTran50	4405	237	171	81
NEW ENGLAND	**2030**	Cap	258	43	37	20
		Cap_HiTran10	260	43	37	20
		Cap_HiTran30	286	46	40	22
		Cap_HiTran50	294	47	41	23
	2040	Cap	603	79	67	28
		Cap_HiTran10	602	79	67	28
		Cap_HiTran30	598	79	66	28
		Cap_HiTran50	597	78	66	28
	2050	Cap	1542	198	156	53
		Cap_HiTran10	1526	195	154	52
		Cap_HiTran30	1495	191	151	50
		Cap_HiTran50	1470	187	148	48

New England by 2030, by up to 1% in New York and 0.4% in New England by 2040, and by up to 27.5% in New York and 3.8% in New England by 2050.

5.4. Electrification

There are competing forces that affect electrification trends in these simulations. Electricity and fuel prices are rising, driving substitution of non-energy inputs for both fuels and electricity. However, fuel prices are rising faster than electricity prices, driving a substitution toward electricity. Under the **Cap** scenario, the delivered price of coal rises by 8–50 times in New York and 2.6-15.4 times in New England over the period of 2030–2050. The price increases in natural gas and refined oil arise less, by 30%–40% in the short run and a 160%–270% toward the end of the simulation horizon (see Table 3). The electricity supply prices, as discussed in section 5.3, increase too but at a lower rate.

In the short run from 2020 to 2030, Fig. 11 shows, relative to the **Ref** scenario, small reductions in electricity consumption in both New York and New England in the **Cap** scenario, compared with the **Ref** scenario. Price induced efficiency and conservation are slightly beating out the fuels-to-electricity substitution effect. Since 2030, the substitution effect takes over and we see overall more electricity use. This in part reflects the more rapid rise in fuels prices, less ability to substitute away from energy as governed by the CES production functions, the elasticity specification in the model, and the fact that we approximate greater fuels-to-electricity substitution capability over time by gradually increasing that elasticity. Relative to the **Ref** scenario, electricity consumption under the **Cap** scenario rises by 18% in New York and 27% in New England by 2040, and by 12% in New York and 53% in New England by 2050. At the same time, fossil fuel consumption reduces by 29% in New York and 40% in New England by 2040, and by 54% in New York and 60% in New England by 2050. In response to the increases in energy prices, total energy consumption decreases by about a quarter by 2040 and more than 40% by 2050.

Under the **Cap_HiTran** scenarios, we find greater electrification starting in 2030, albeit the increase is very small. Along with more hydro imports, fuel use reduces further with greater electrification in New England throughout the horizon and in New York through 2040. Beyond 2040, New York's electricity consumption continues to grow, with somewhat less reduction in fuel use with higher transmission capacity. We found more gas consumed by the electricity sector to meet higher demand due to electrification. To stay under the emissions cap, this gas is used by CCS technology.

5.5. Carbon prices and emissions

To meet the emissions reduction target that increases from about 20% to 80% relative the 1990 level for New England and a few-percentage more ambitious reduction target for New York, carbon prices are generated as an endogenous result of the cost-driven abatement activities in each regional economy. Compared to New York where carbon price starts with \$24/tCO_2 in 2020 growing to \$115/tCO_2, \$315/tCO_2, \$815/tCO_2 by 2030, 2040, 2050, respectively, New England starts with a smaller carbon price in 2020 at \$13/tCO_2 rising to \$125/tCO_2, \$238/tCO_2, \$591/tCO_2 by 2030, 2040, 2050, respectively (see Table 4). The increasing carbon prices are a result of the more stringent emission policy over time combined with higher costs of abatement technologies when decarbonization becomes deeper.

When transmission capacity expands along with more hydro imports starting in 2026, the carbon prices decrease as expected, reflecting the contribution of imports to total power supply. While hydro import has a direct impact on reducing the abatement cost of the electricity sector, it has an indirect impact on the carbon prices which are determined by the abatement potential of all sectors in the economy. Less expensive hydro imports from Canada lead to lower electricity prices which change the relative economics between energy sources. Sectors that can take the cost advantage through electrification offer greater abatement potential, whereas sectors that have to stick to their energy use structure provide less abatement potential. The small changes in the carbon prices across the **Cap_HiTran** scenarios suggest the potential of further abatement is small at the level of required emissions reduction.

With an equalized carbon price in place across sectors, emissions abatement can vary by sector depending on the availability and economic competitiveness of low-carbon technologies that can be deployed to substitute for the existing technology (see Table 5). The electricity sector, rich in low-carbon technology options, cuts emissions by more than a half under the **Cap** scenario relative to the **Ref** scenario by 2030, and over 75% by 2050. Lacking low-carbon technology representation (e.g. heat pumps to provide heating and air-conditioning services) smart metering, for the residential and commercial sectors, we have parameterized each economic sector with a time-varying elasticity that grows over time to approximate the decarbonization opportunities that allow greater substitution between electricity and fossil fuels. The emissions reductions, in terms of percent change from the **Ref** scenario, in the

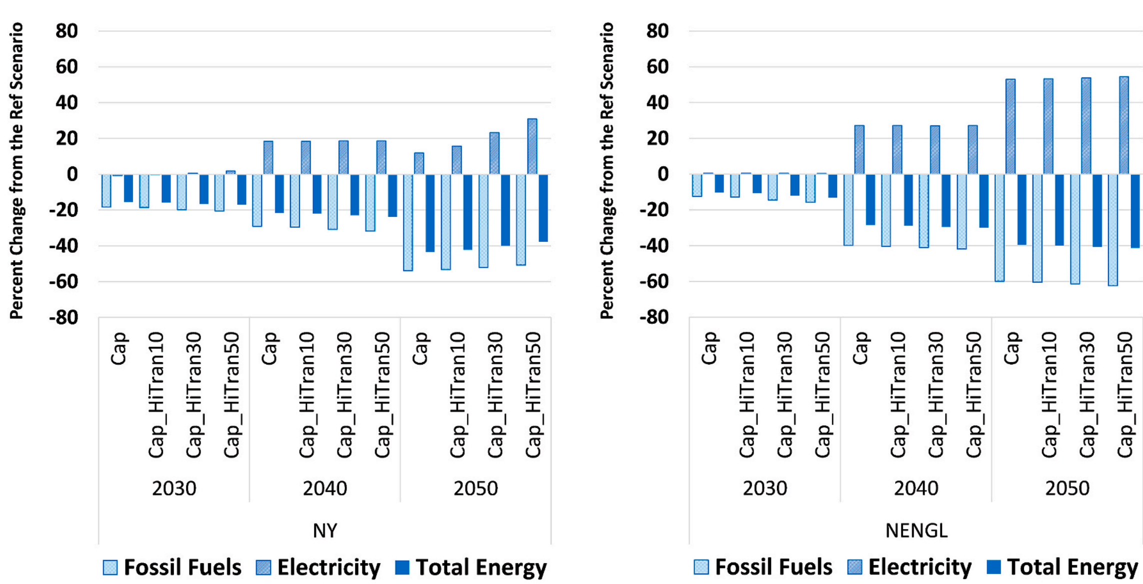

Fig. 11. Energy consumption [percent change from the **ref** scenario].

Table 4
Carbon Prices [2018$/$tCO_2$].

REGION	SCENARIO	2020	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040	2042	2044	2046	2048	2050
NEW YORK	Cap	24	63	84	94	93	115	151	217	243	314	315	329	376	461	609	815
	Cap_HiTran10	24	63	84	93	93	115	151	216	242	312	315	320	363	447	591	794
	Cap_HiTran30	24	63	84	88	93	125	150	214	242	312	314	317	342	424	561	757
	Cap_HiTran50	24	63	84	83	91	127	150	212	240	311	314	316	339	404	539	723
NEW ENGLAND	Cap	13	56	73	93	101	125	165	238	245	241	238	249	308	419	506	591
	Cap_HiTran10	13	56	73	93	101	126	165	237	245	241	238	249	306	415	506	585
	Cap_HiTran30	13	56	73	74	97	135	164	234	245	241	236	247	302	405	505	573
	Cap_HiTran50	13	56	73	65	92	138	163	232	245	241	236	246	300	393	505	564

residential and commercial sectors are on par with the electricity sector toward the end of the horizon.

USREP characterizes the private transportation sector dynamics with a differentiation between the new and used vehicle fleets, a representation of fleet stock turnover, and an explicit representation of the plug-in hybrid electric vehicle (PHEV) and battery electric vehicle (BEV). PHEV and BEV provides low-carbon fuel-efficient transportation alternative and are treated as perfect substitute for the conventional internal combustion engine (ICE) vehicle.[14] With a carbon price, PHEV/BEV becomes more economically competitive relative to the ICE vehicle. Substituting ICE vehicle with PHEV/BEV reduces the emissions of the sector. However, the expansion of PHEV/BEV fleet is subject to the fleet turnover rate. The results show small emission reduction from private transportation by 2030. By 2050, the private transportation is fully decarbonized in both New York and New England.

Compared with private transportation, commercial transportation lacks low-carbon alternatives in USREP thus the sectoral emissions reduction is completely driven by the electrification governed by the elasticity of substitution between electricity and transport fuel consumption.

Likewise, there is no explicit representation of low-carbon technologies in USREP for the industrial sector. The emissions reductions are driven by the CES technology function that minimizes cost of production given the change in relative prices of inputs.

Under the **Cap_HiTran** scenarios, we find a different trend in sectoral emissions abatement between New York and New England in 2050 when compared in terms of percent change from the **Ref** scenario. With more hydro imports under transmission capacity expansion, electricity emissions increase in New York and decrease in New England. As discussed in section 5.4, there is a substantial increase in electricity consumption in response to a large reduction in electricity price in New York. The increase in electricity consumption dominates the reduction in electricity emission intensity given a higher level of hydro imports, resulting in higher electricity sector emissions and leaving a higher abatement burden on other sectors, e.g. the residential and commercial sectors. In New England, the increase in electricity consumption is dominated by the reduction in emission intensity associated with electricity generation as a result of increasing level of hydro imports, generating less electricity sector emissions.

5.6. Generation

Fig. 12 presents in detail the evolution of the generation mix for New York and New England from 2016 until 2050. In the **Ref** scenario, the RPS is met mostly by wind generation. Cross-border trade with Canada and inter-regional trade with neighboring regions is observed in both New York and New England. In the emission policy scenarios (**Cap** and **Cap_HiTran**) there is more generation from low-carbon technologies such as Gas with Carbon Capture and Storage (Gas-CCS) and wind and solar generation.[15] The use of utility-scale storage also increases with the need to address variability of supply that result from the large amounts of intermittent renewable generation. The expansion of the cross-border transmission line capacity in the **Cap_HiTran** scenarios reduces the level of penetration of mostly Gas-CCS (more pronounced in New England) and delays the installation of wind and solar especially

[14] The assumption of PHEV and BEV are perfect substitutes for the conventional internal combustion engine vehicles may be overly optimistic for long-distance driving.

[15] We recognize that our results show in particular a relevant role of GasCCS in the generation mix in the case of New York. We need to point out that, since we did not include a resource limit for carbon sequestration in both regions, our results might be overestimating electricity generation coming from this particular technology. Later versions of our model will include data on the potential for CCS in both US Northeastern regions.

Table 5
Sectoral carbon emissions [percent change from the **ref** scenario].

		Cap			Cap_HiTran10			Cap_HiTran30			Cap_HiTran50		
REGION	**SECTOR**	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
NEW YORK	Residential	−19	−52	−72	−20	−52	−73	−22	−52	−75	−23	−52	−77
	Commercial	−26	−63	−86	−27	−63	−86	−29	−63	−87	−29	−63	−88
	Industrial	−9	−33	−50	−9	−33	−50	−9	−32	−50	−10	−32	−50
	Transportation	−20	−43	−92	−20	−43	−91	−21	−43	−91	−22	−43	−90
	Commercial	−42	−51	−78	−42	−50	−77	−43	−50	−76	−44	−50	−74
	Private	−3	−38	−100	−4	−38	−100	−5	−38	−100	−5	−38	−100
	Electricity	−54	−81	−88	−53	−81	−87	−47	−82	−86	−45	−83	−85
NEW ENGLAND	Residential	−18	−36	−69	−18	−35	−69	−19	−35	−69	−19	−35	−69
	Commercial	−45	−45	−76	−43	−45	−76	−38	−45	−75	−38	−45	−75
	Industrial	−8	−11	−22	−8	−11	−22	−8	−11	−22	−8	−11	−22
	Transportation	−7	−56	−86	−7	−56	−86	−7	−56	−86	−7	−55	−86
	Commercial	−17	−21	−59	−17	−21	−59	−18	−21	−59	−18	−21	−58
	Private	−2	−75	−100	−2	−75	−100	−2	−74	−100	−2	−74	−100
	Electricity	−54	−71	−75	−56	−71	−76	−57	−72	−77	−58	−73	−78

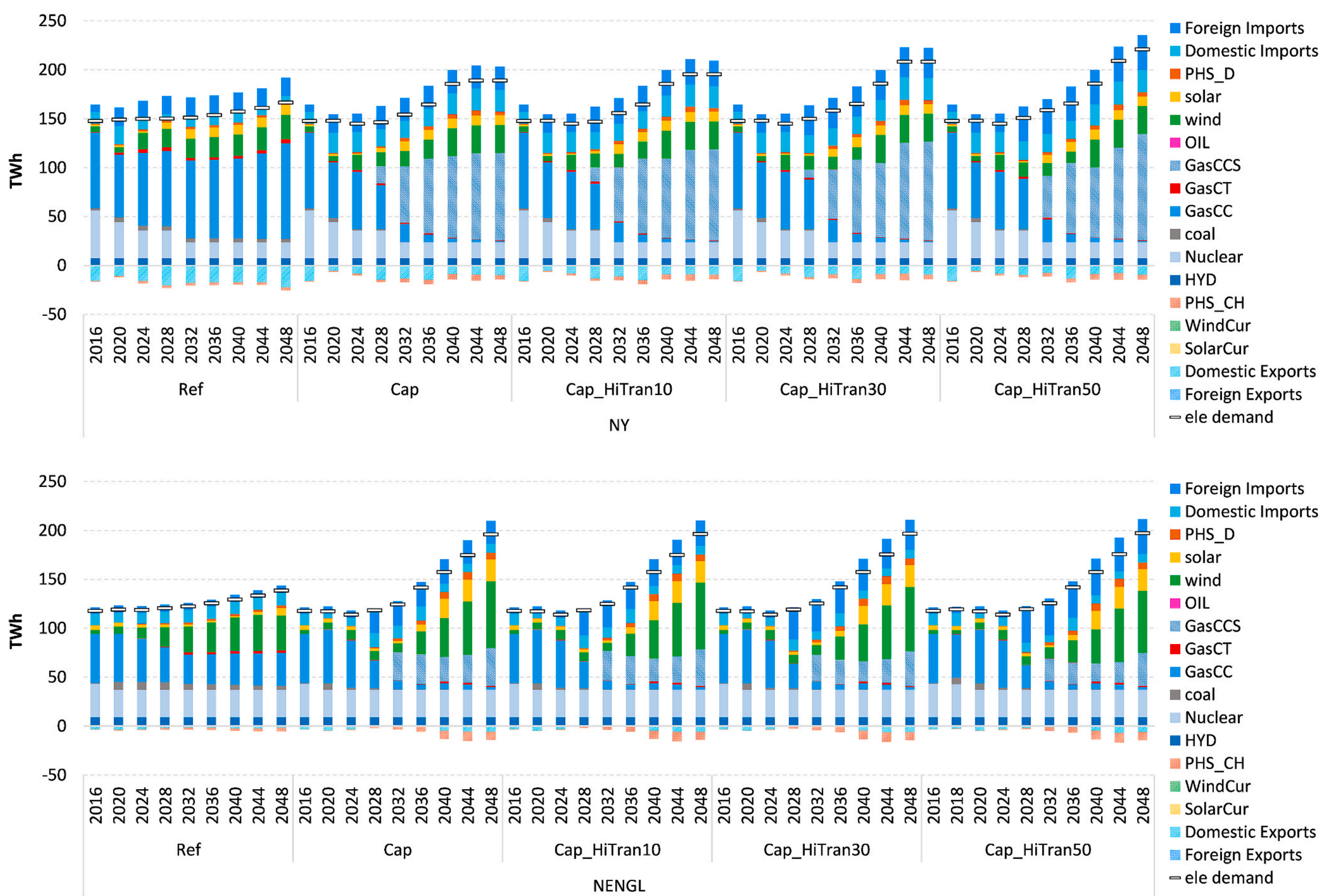

Fig. 12. Evolution path of the generation mix for New York and new england [TWh] tables..

before 2040.

Table 6 shows aggregated domestic generation for New York and New England, and net energy trade[16] from Canada for all cases for years 2030, 2040 and 2050. We note that for earlier years hydro imports displace mostly gas technologies in New York and New England, and delays the installation of renewables in the case of New England. For later years, we observe increasing electrification levels in New York, leading to larger domestic generation and imports, while in New England the impact is mostly on a decrease of gas-fired generation and a decrease of imports from New York.

6. Concluding remarks

EMF34 was designed to examine North American energy trade and integration. Further expansion of transmission capacity across borders in the region is a necessary element for integration of electricity markets. In this paper we have focused on the effects of expanding transmissions capacity between Canada and the US Northeast, a region that has ambitious goals for wind and solar and for reducing carbon emissions. This further integration has particular interest for these regions because there is the potential for hydro power from Quebec to be used to

[16] Positive values indicate imports, while negative values denote exports.

Table 6
Electricity imports from Canada and domestic generation for New York and new england [TWh].

			Renewables	Coal	Nuclear	Gas	Domestic Trade	Foreign Trade	Demand
NEW YORK	**2030**	Ref	36.3	4.4	28.2	77.6	−14.3	18.3	150.7
		Cap	31.0	0.8	28.2	62.3	3.8	23.4	149.4
		Cap_HiTran10	29.0	0.8	28.2	61.6	5.1	25.8	150.5
		Cap_HiTran30	24.6	0.9	28.2	60.0	7.1	30.5	151.3
		Cap_HiTran50	21.9	1.1	28.2	58.1	8.7	35.3	153.2
	2040	Ref	38.3	3.7	16.1	84.7	−4.5	18.3	157.1
		Cap	45.1	0.0	16.1	87.9	12.9	23.4	185.5
		Cap_HiTran10	45.1	0.0	16.1	85.6	12.8	25.8	185.6
		Cap_HiTran30	45.1	0.0	16.1	81.0	13.1	30.5	185.8
		Cap_HiTran50	45.1	0.0	16.1	76.5	12.9	35.2	185.9
	2050	Ref	43.3	3.2	16.1	104.0	−15.4	18.3	169.6
		Cap	45.3	0.0	16.1	83.3	20.6	23.6	189.0
		Cap_HiTran10	45.3	0.0	16.1	87.5	20.5	25.9	195.4
		Cap_HiTran30	45.3	0.0	16.1	95.3	20.8	30.7	208.2
		Cap_HiTran50	45.3	0.0	16.1	103.2	21.0	35.4	221.0
NEW ENGLAND	**2030**	Ref	35.8	7.4	28.1	32.3	10.5	7.4	121.4
		Cap	19.8	0.8	28.1	33.7	13.2	25.0	120.7
		Cap_HiTran10	19.8	0.8	28.1	32.4	12.0	27.6	120.6
		Cap_HiTran30	19.8	0.9	28.1	28.9	10.1	32.6	120.4
		Cap_HiTran50	19.8	1.0	28.1	25.2	8.7	37.6	120.3
	2040	Ref	44.3	5.0	28.1	34.4	10.2	7.3	129.3
		Cap	67.2	0.2	28.1	33.1	4.1	24.7	157.4
		Cap_HiTran10	66.0	0.2	28.1	31.8	4.1	27.2	157.4
		Cap_HiTran30	63.9	0.2	28.1	29.0	4.0	32.2	157.3
		Cap_HiTran50	61.2	0.2	28.1	26.7	4.1	37.2	157.5
	2050	Ref	55.0	3.9	28.1	35.4	11.0	7.4	140.8
		Cap	104.7	0.0	28.1	50.5	−4.2	23.0	202.2
		Cap_HiTran10	104.7	0.0	28.1	48.6	−4.1	25.3	202.6
		Cap_HiTran30	104.7	0.0	28.1	45.3	−4.4	29.7	203.3
		Cap_HiTran50	104.6	0.0	28.1	42.2	−4.7	33.9	204.2

complement the expansion of intermittent solar and wind power in the US Northeast.

Applying a newly developed integrated top-down bottom-up modeling framework, we built scenarios that include: (i) a Reference scenario with existing and projected RPS policies in New York and New England, (ii) a Cap scenario that implements an economy-wide CO_2 emission cap with reductions targets relative to 1990, and (iii) three Cap scenarios with expanded transmission capacity from Canada into the US Northeast. The high transmission scenarios are consistent with guidance under EMF34 Core Scenario 6.1, expanding capacity by 10, 30, and 50%. Our objective was to examine the potential economic benefits of such expansion (in terms of reduced cost of meeting emissions reduction goals), and to examine how the hydro imports would be used within the electricity system as well as the broader impacts on electricity generation costs and electrification trends.

A 50% expansion in transmission capacity is substantial, however, the additional amount of imports such expansion would allow is modest relative to the size of the electricity markets in New York and New England. There are benefits. To put these benefits in context, we calculated the savings in welfare costs (measured as equivalent variation) per kWh of additional electricity imported. We found the value to the economy of transmission capacity expansion ranging from \$.38 -\$.49 per kWh in New York, and \$.30-\$.33 per kWh in New England by 2050, values that are significantly larger than the cost of the electricity itself. In our scenarios, the expansion of transmission capacity was imposed exogenously, and any cost of such expansions was not included in our estimate of benefits of additional imports. We also assumed that there would be sufficient hydro power to meet any demand in the US Northeast. Electricity prices in Quebec are much lower than in the US Northeast. We assumed that additional power demand could be met at the existing monthly power import prices. Under these assumptions, we found that the additional transmission capacity was fully utilized throughout the year for most of the period through 2050. The exception was a slight drop in utilization into New England after 2040. Along with the drop, we found the changes in inter-regional trade flows where New England increases electricity export to New York while reducing electricity imports from New York, implying there is excess Canadian imports to New England that is passed through regional intertie to New York. Given that the relative economics of Canadian hydro imports were so favorable, there was no incentive to vary the use of these imports to make up for variability of wind and solar power production except for post 2040 in New England. Instead, other resources (storage, flexible gas, imports from other regions in the US) were used for that purpose. The carbon limits we imposed raise fuel prices more than electricity prices and as a result we found greater electrification in both New England and New York, especially from 2030 onward.

CRediT authorship contribution statement

Mei Yuan: Methodology, Software, Data curation, Formal analysis, Investigation, Visualization, Writing – original draft, preparation, Funding acquisition. **Karen Tapia-Ahumada:** Methodology, Software, Data curation, Formal analysis, Investigation, Visualization, Writing – original draft, preparation, Funding acquisition. **John Reilly:** Conceptualization, Supervision, Validation, Writing- Review and Editing, Funding acquisition.

Declaration of competing interest

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

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Appendix A. Technology Costs and Operational Performance Parameters, Transmission Capacity Limits, Wind and Solar Installed Capacity and Resource LimitationsAppendix A is dedicated to parameter assumptions and data used in the EleMod model, including Table A.1 and Table A.2 on cost and performance parameters for generation technologies, Table A.3 on existing transmission line capacity between regions, Table A.4 on installed capacity for wind and solar, and Table A.5 on regional renewable resource limits

Table A.1
Conventional Generation Technologies: Operational Parameters and Performance

		Minimum Plant Loading [%]	Availability Factor [p.u.]	Forced Outage Rate [p.u.]	Electric Heat Rate [MMBtu/kWh]	CO2 Emission Factor [Metric ton/MMBtu]
Gas Combustion Turbine	GasCT	0%	0.9215	0.0300	0.010033	0.0540
Gas Combined Cycle	GasCC	0%	0.9024	0.0400	0.006682	0.0540
Gas Combined Cycle with Carbon Capture & Sequestration	GasCCS	0%	0.9024	0.0400	0.007525	0.0081
Oil/gas Steam Turbine	OGS	40%	0.7927	0.1036	0.098400	0.0805
Pulverized Coal Steam with SO2 scrubber	CoalOldScr	40%	0.8460	0.0600	0.010400	0.0930
Pulverized Coal Steam without SO2 scrubber	CoalOldUns	40%	0.8460	0.0600	0.011380	0.0930
Advanced Supercritical Coal Steam with SO2 & NOx Controls	CoalNew	40%	0.8460	0.0600	0.008784	0.0930
Integrated Gasification Combined Cycle Coal	CoalIGCC	50%	0.8096	0.0800	0.010062	0.0930
IGCC with Carbon Capture & Sequestration	CoalCCS	50%	0.8096	0.0800	0.010062	0.0140
Pulverized Coal Steam with SO2 scrubber & Biomass Cofiring	CofireOld	40%	0.8463	0.0700	0.010740	0.0930
Advanced Supercritical Coal Steam with Biomass Cofiring	CofireNew	40%	0.8463	0.0700	0.009370	0.0930
Nuclear Plant	Nuclear	100%	0.9024	0.0400	0.010452	–

Sources: Data mostly based on reports from EIA AEO, NREL's ReEDS, and 2016 ATB reports.

Table A.2
Technology Costs (2018$)

		Annualized Capital and Fixed Costs [$/kW]	Variable O&M [$/kWh]	Lifetime [yr]
Gas Combustion Turbine	GasCT	103.22	0.0128	30
Gas Combined Cycle	GasCC	177.44	0.0033	30
Gas Combined Cycle with Carbon Capture & Sequestration	GasCCS	270.20	1.2350	30
Oil/gas Steam Turbine	OGS	146.81	0.0036	50
Pulverized Coal Steam with SO2 scrubber	CoalOldScr	196.07	0.0084	60
Pulverized Coal Steam without SO2 scrubber	CoalOldUns	159.83	0.0125	60
Advanced Supercritical Coal Steam with SO2 & NOx Controls	CoalNew	362.28	0.0042	60
Integrated Gasification Combined Cycle Coal	CoalIGCC	795.95	0.0072	60
IGCC with Carbon Capture & Sequestration	CoalCCS	624.83	1.2350	60
Pulverized Coal Steam with SO2 scrubber & Biomass Cofiring	CofireOld	216.18	0.0125	60
Advanced Supercritical Coal Steam with Biomass Cofiring	CofireNew	377.80	0.0084	60
Nuclear Plant	Nuclear	791.07	0.0042	40
Wind Onshore	WindOn	313.09	–	20
Wind Offshore	WindOff	623.15	–	–
Utility Solar	Solar	254.23	0.0135	30
Pumped Hydro Storage	PHS	115.96	0.0088	50

Sources: EIA, NREL, NREL reports.

Table A.3
Total Capacity of Transmission lines between Regions (GW)

Region 1	Region 2	Transmission Limit [GW]
New York	New England	2.034
LMATL	New York	2.000
Canada	New York	2.700
Canada	New England	2.870

Source: Bouffard et al. (2018).

Table A.4
Installed Capacity for Wind and Solar (GW)

Region	Resource	Installed capacity by 2016 [GW]
New York	Onshore Wind	1.829
New England	Onshore Wind	1.358
New York	Solar PV	1.246
New England	Solar PV	2.900

Source: Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860).

Table A.5
Resource Limits for Wind and Solar (GW)

Region	Resource	Resource Limit [GW]
New York	Onshore Wind	9.799
New England	Onshore Wind	18.431
New York	Solar PV	6.709
New England	Solar PV	16.137

Note: For these limits, we clustered wind/solar photovoltaic regional potential capacity for all resource classes within cost class #1 for all states within New England and New York, based on information provided in EPA's Power Sector Modeling Platform v6.

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