Assessing the Impacts of Increasing Transmission Capacity on the Electric Power Sector in New England

by

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ABSTRACT

This thesis explores the evolution of the electric power sector in New England under the expansion of transmission capacity and under policy with increasing Clean Energy Standards (CES). I use EleMod, a Capacity Expansion Planning model, to compare (1) the reference case of current transmission assets, (2) increasing transmission interface capacities within New England, (3) increasing interconnection capacities with Canada, and (4) both capacity expansions. Transmission expansion allows electricity trade between states and enables them to take advantage of localized, intermittent resources like wind power. Increasing the interconnection capacity with Canada allows the system to optimally allocate the available hydropower energy for imports in the hours of highest net demand. Both transmission expansions together make even stronger use of their contributions.

For the capacity expansion model, I choose a set of generation technologies available in New England, and supply cost and operational data from public domain sources. My contributions to EleMod include: (1) the representation of transmission interfaces for New England; (2) the addition of an CES policy standard forcing generation shares from a subset of CES-eligible resources; (3) the modeling of an external hydro reservoir resource in Canada that can be used to supply the load in New England based on cross-border interconnection constraints and the total available energy per year; and (4) the detailed state-level representation of the New England power sector with generation technologies, installed capacities, transmission interface capacities, and CES targets.

Policy scenarios increase CES from an average of 25% in 2018 in the base scenario to 95% in 2050 in the decarbonization scenario. Through all policy scenarios, combined-cycle gas plants (GasCC) with carbon capture and storage (CCS) technology dominate the capacity expansions. Increases in transmission capacity lead to higher shares of wind in generation, especially when both transmission and interconnection are expanded. Natural gas, in the form of GasCC with and without CCS, takes shares of the generation mix of up to 85% by 2050. Thus, I also assess the role of pipeline capacities into New England. Because other natural gas uses like residential heating demand have priority over generators, gas-fired power plants cannot expect to meet all their demand during critical periods of shortage in the winter. However, this issue is part of a larger integrated resource planning process.

Both transmission and interconnection expansion reduce total system costs by an annual 3.95% and 4.29%, respectively. Because transmission costs are not included in the model, I separately assess the costs and benefits of both transmission expansion scenarios. Transmission expansions from Maine to Massachusetts of 2,000 MW and interconnection expansions to Canada of 3,000 MW and 4,500 MW from Maine and Vermont, respectively, allow for optimal allocation of flows across lines in over 90% of the hours. For interconnection, the calculation estimates costs to be about 1% higher than the benefits, and for transmission within the region the benefits exceed the costs by about 40%.

1. INTRODUCTION

The scientific consensus is clear that the effects of man-made climate change are real, and if unmitigated will potentially be drastic (IPCC 2014). In response to this challenge, 195 UN Member States signed the Paris Agreement, an international treaty with the ambitious goal to keep the increase of average global temperatures under 2°C. This signifies the acknowledgement of the problem of climate change at the highest levels of global society, and, even more important, shows the emergence of a plan to take action. Decarbonization has become the widely agreed upon strategy to effectively combat climate change over the course of the 21st century (Carley 2011; Hübler & Löschel 2013). The electric power sector in particular is expected to play a critical role in reducing emissions (Williams et al. 2012). This thesis focuses on the issues related to decarbonization of electricity.

In the United States, federal policy addressing climate change has been difficult to implement and the government's future role in the Paris Agreement is uncertain. However, many states are dedicated to combatting climate change. New England, the region including the six Northeastern-most states of the US, has set ambitious emissions reductions targets (35–45% below 1990 levels by 2030). The six states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont) have also committed to stringent emissions reductions for the electric power sector (30% below 2020 levels by 2030) through the Regional Greenhouse Gas Initiative (RGGI 2017). While the RGGI carbon trading mechanism is in place, its effect on emissions has been limited thus far due to low permit prices. However, another policy measure—Renewable Portfolio Standards (RPS) – has been playing a key role in meeting carbon emissions reductions goals in the electric power sector. Across the United States, the electric power sector contributed 35.2% of total emissions in 2016 (down from an average of 40% of emissions in the 2000s) (IEA 2018). 29 states, including those in New England, have passed RPS policies to bring low-carbon generation into the mix and lower the emissions from the electric power sector. Collectively, state RPS policies have contributed more than 60% of all renewable generation since 2000, and states successfully meet their annual targets around 95% of the time (Barbose 2016).

A similar policy tool is the Clean Energy Standard (CES). As a policy, CES works exactly like an RPS, but it is more inclusive in the types of technologies it accepts to meet the proposed standard of electricity generation, focusing on all technologies that can deliver low-carbon electricity instead of providing support only for a select few resources like an RPS. In comparison to a cap-and-trade policy, CES performs similarly, and in some cases it is even more cost-effective than cap-and-trade

(Goulder, Hafstead & Williams 2014). In comparision to an RPS, CES is more cost-effective as it includes a wider range of technologies to choose from in order to minimize costs. CES received wide attention when President Obama offered the goal of 80% clean energy by 2035 in his State of the Union Address in 2011, and the Senate Committee on Energy and Natural Resources followed this proposal up with a white paper on CES (Bingaman & Murkowski 2011). Some states, such as New York, have already moved to a CES instead of an RPS. Moving forward, CES is likely to be the policy solution of choice to advance the decarbonization of the electric power sector.

Decarbonization is likely to be the determining factor for transitions in the electric power sector in both the near- and long-term, and this is also true for New England. For this reason, I conduct my research on the electrictric power sector in New England under policy scenarios encouraging decarbonization. I therefore analyze three policy scenarios: (1) a baseline CES requirement equivalent to current RPS commitments by New England states (CESbase), which range from 13% in Rhode Island to 19.1% in Massachusetts and 55% in Vermont; (2) an increased CES trajectory with further commitments by all states, similar to Massachusetts' commitment to increase its RPS by 1% annually (CEShigh); and (3) a set of CES requirements that meet decarbonization targets for the electric power sector by requiring 95% renewable electricity by 2050 (CESdecarb). While the magnitudes of commitments to CES, RPS or RGGI are highly uncertain, these scenarios illustrate three possible trajectories of the strength of climate change policies that we may reasonably expect through 2050.

As clean energy targets increase for New England, there are several opportunities for the region to decrease the carbon intensity of its electricity, including: developing wind power on-shore in Maine or off-shore in Massachusetts; using more biomass from Maine, New Hampshire, and Vermont; continuing to increase natural gas, potentially in combination with carbon capture and storage (CCS); building advanced nuclear reactors; and importing hydro power from Quebec. In my analysis I examine a selection of these technological options.

Crucially, many of these options require increased transmission capacities. Wind power and biomass are highly localized resources and additional transmission connecting them to load centers would be required. Similarly, regional integration with Canada to allow for larger hydro import quantities during peak hours would also require new transmission lines. These two stories are key pieces of the transition to a decarbonized electric power sector: expansion of transmission capacity on the intra-regional level can take advantage of localized generation resources (Lund 2005; Söder et al. 2007), and efforts of regional electricity market integration, primarily enabled by expansion of interconnector transmission lines, can enable the intra-regional co-optimization of electric power systems (Pellini 2012).

The purpose of this thesis is thus to explore how increased transmission capacity within New England and connecting to Canada impacts the evolution and cost of the electric power sector in New England under policy scenarios of increased CES target trajectories.

To do so, I adapt an electricity capacity expansion model EleMod (Tapia-Ahumada et al. 2014) to represent individual states in New England. I add a representation of hydro resources in Canada as well as the current interconnection capabilities to model the benefits from increased integration. I explore scenarios with increased transmission capacities between New England states to take advantage of localized resources (*TransNEngl*), and increased transmission capacity with Canada to incorporate the benefits of regional hydro-thermal integration (*TransCan*), which I compare to the current levels of transmission capacity (*TransRef*). Finally, I track the evolution of the resource mix and total electric power sector costs until 2050 across the three CES policy scenarios (*CESbase*, *CEShigh*, and *CESdecarb*).

My thesis is structured as follows: In Chapter 2 I present an in-depth look into the New England electric power sector and its efforts of emissions reductions (see Section 2.1), the landscape of electricity generation (see Section 0), and specifically the low-carbon generation technologies that might play a role in decarbonization (see Section 2.3). Then, I conduct a literature review on approaches to studying decarbonization scenarios in the electric power sector (see Section 3.1), and I review the methodology of choice for my analysis—Capacity Expansion Planning (CEP)—in Section 3.2. CEP is widely used to study electric power sector developments, and I provide an overview of various CEP studies conducted by research groups world-wide and identify the shortcomings which I aim to address with my modeling approach. In Chapter 4, I introduce the linear optimization model EleMod which I use to gain insight into long-term capacity expansion investments in New England, and the additions I made to the model. In Chapter 5, I introduce the scenarios which I use in my analysis: by comparing four transmission scenarios, I quantify the benefits of expanding the transmission grid in New England and the interconnection with Canada under policy scenarios with different levels of CES targets. Then, in Chapter 6, I present the results of my exploration of the effect of hydropower imports from Canada and increased trade within the region on long-term capacity expansion decisions and total system costs of the electric power sector in New England. Across all scenarios, I also evaluate the electricity trade flows to estimate the necessary transmission capacity expansion and conduct a first-order cost-benefit calculation. Furthermore, I evaluate the role of natural gas by tracking the fuel demand across the scenarios and comparing it with existing pipeline capacities. I conclude in Chapter 7 by offering insights and recommendations for the evolution of the electric power sector in New England.

2. THE ELECTRIC POWER SECTOR IN NEW ENGLAND

In this chapter, I review the state of the electric power sector in New England. I start by introducing the emissions reductions efforts through the Regional Greenhouse Gas Initiative (RGGI), Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES) in New England (see section 2.1). I also make the case to use CES as a policy to analyze the stringent decarbonization scenarios in my analysis. Then, I provide an overview of electricity generation in New England (see section 0), focusing on the recent transitions from coal to gas-fired power plants, and the partial phase-out of nuclear power. Finally, I survey the available low-carbon generation technologies in New England for the current transition to more low-carbon generation sources (see section 2.3), among them wind power, natural gas with CCS technology, biomass (with or without CCS), and hydropower imports from Canada.

2.1. Emissions Reductions and Renewable Portfolio Standards

New England has stated its climate goals in the joint declaration of the Conference of New England Governors and Eastern Canadian Premiers (NEG-ECP) in 2001. The emissions target for 2010 (returning to 1990 emissions levels) was surpassed, and the region is on track to achieve its 2020 target of reducing emissions 10% below 1990 levels (Coalition of Northeastern Governors & Eastern Canadian Secretariat). The targets continue to increase in stringency over time, with a planned reduction by 2030 of 35 – 45% below 1990 levels. In 2050, the end of the time horizon for my study, the region projects to reduce overall economy emissions to 75 – 85% below 2001 levels, which are less than 87.5 Mt (million metric tonnes) of CO_2 equivalents.

Table 1: New England greenhouse gas emissions targets and status of progress

Year	Target	Mt of CO_2 equivalent	Status
1990	–	330	–
2010	Return to 1990 levels	330	4.1% below
2020	10% below 1990 levels	297	On track
2030	35 – 45% below 1990 levels	181.5 – 214.5	–
2050	75 – 85% below 1990 levels	52.5 – 87.5	–

To achieve emissions reductions, economists' favorite tool is carbon pricing (Newcomer et al. 2008; Weitzman 2014). There are two basic ways to put a price on carbon: implement a carbon tax or implement a cap and trade market. For the electric power sector, New England has implemented the latter with its Regional Greenhouse Gas Initiative (RGGI). Together with Delaware, Maryland, and New York, the New England states implemented this cap-and-trade regime, which sets a total budget for CO_2 emissions from all conventional power plants over 25 MW. Allowances that permit a power plant to emit CO_2 need to be acquired either in one of the quarterly auctions, or through trades from other allowance-holders.

However, RGGI is deemed to have been of limited effectiveness thus far. After initial low permit prices due to too high carbon budgets that were not exhausted by the industry, the initiative received a boost when states agreed to reduce the budget (Ramseur 2017). After an initial increase in auction results, however, the permit prices have since plummeted again to very low clearing prices (see Figure 1).

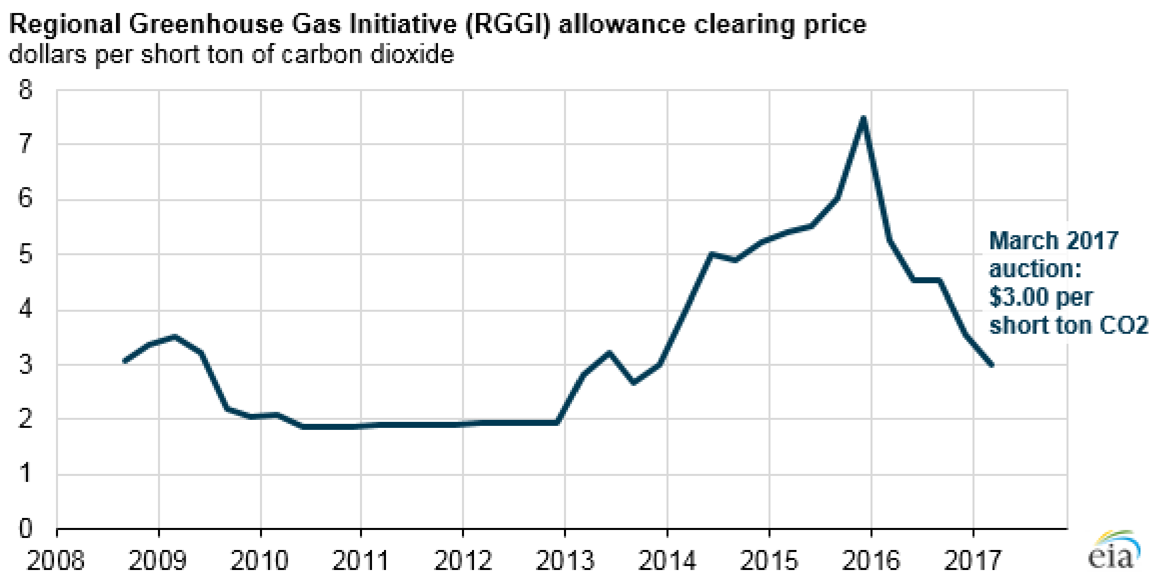

Figure 1: RGGI allowance clearing price (EIA 2017a)

The fact that RGGI has not been able to tighten carbon budgets to levels where carbon price auctions make a meaningful difference on emissions from the electric power sector is at least partly due to some of carbon pricing's practical drawbacks. Strong opposition from industry groups who are under threat to lose valuable assets under a carbon pricing regime can take away the teeth of a carbon pricing instrument through influence on the technical details like which carbon budgets are set (Jenkins 2014).

As an alternative policy measure, states have also introduced RPS which have successfully reduced emissions in the electric power sector. An RPS requires that a certain percentage of electricity generation come from specified renewable. RPS policies have been widely and successfully employed in the US since the early 2000s (Rabe 2007; Wiser & Barbose 2008). All New England states have implemented RPS targets for their electricity sector, mandating their utilities to buy Renewable Energy Credits (RECs) for a given percentage of electricity generation, with that percentage differing by state (see Figure 2). Which technologies qualify as "renewable" also varies by state, but commonly include wind, solar, biomass, and new hydro installations.

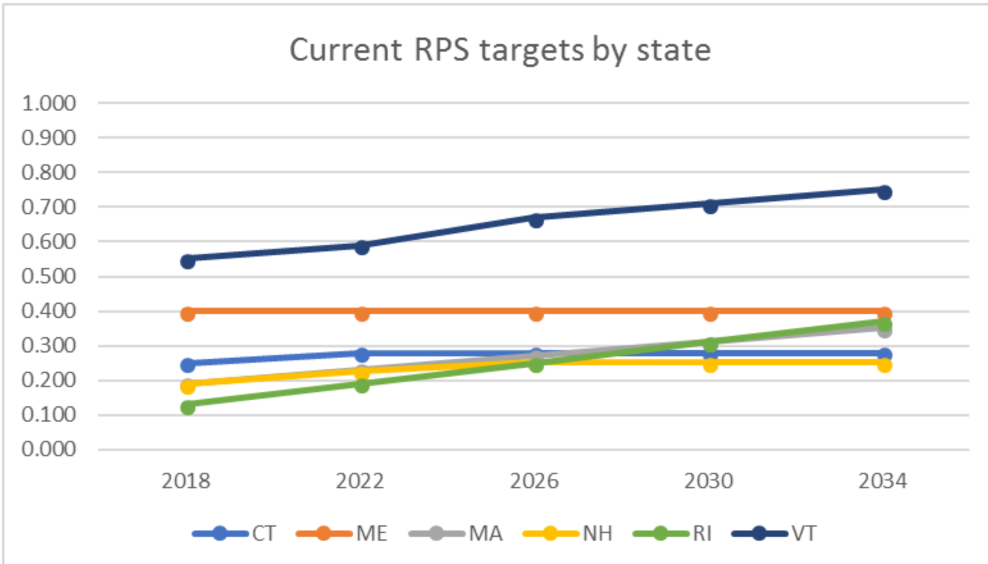

Figure 2: Current RPS targets in New England by state (ISO-NE 2016)

There are indications that for the future, CES will be the policy solution of choice to advance the decarbonization of the electric power sector in New England. CES and RPS are almost the same. They both mandate that a certain percentage of electricity generation must be met by generation resources from an eligible portfolio, and these resources receive credits for generating energy which they can sell on a secondary market. The key difference between CES and RPS is the makeup of their portfolios. Whereas in an RPS portfolio, states almost exclusively include "true" renewable sources like wind, solar, and in some cases biomass, CES offers credits to all types of resources which emit low amounts of carbon in power generation, such as gas or coal with CCS, advanced nuclear or hydro.

New York, a neighboring state to New England, which also supplies renewable energy credits to the New England markets,[1] has adopted a new CES policy in 2016 to replace its expired RPS policy. The new CES mandates 50% clean energy by 2030, which can be supplied by renewable generation

[1] NEPOOL GIS, the REC accrediting institution, accepts renewable energy credits from New York, but also from Delaware, Maryland, New Jersey, and Pennsylvania.

eligible before under the RPS, as well as co-fire generation at its rate of biomass as a fuel, nuclear and hydro plants. A CES yields emissions reductions, but is more agnostic of technology and does not "pick winners and losers" as deliberately as an RPS (Victor & Yanosek 2011). In addition, cost reductions in comparison to an RPS provide a good incentive for policy-makers to choose CES as a strategy for decarbonization.

In order to assess the difference in costs between an RPS and a CES, I conduct two exploratory runs of my model. RPS-eligible technologies are wind, solar, and hydro resources in Maine.[2] CES-eligible technologies include the RPS-eligible technologies as well as biomass, natural gas combined-cycle plants with carbon capture and storage (GasCCS), and coal with CCS (CoalCCS).[3] The results show that the application of a CES leads to significantly lower system costs, totaling 17% or $1.89 billion for the year of 2050 (see Figure 1). Especially considering the dim outlook regarding a functioning cap-and-trade program anywhere between Brussels and California, CES is a second-best option worth exploring.

For these reasons, I construct my three policy scenarios based on CES targets rather than an RPS or total emissions reductions in the form of a cap on RGGI emissions allowances.

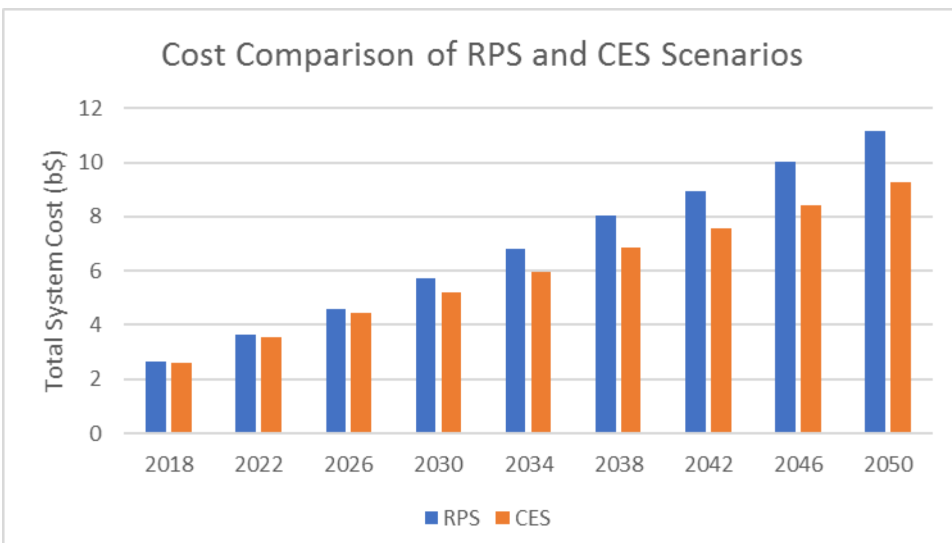

Figure 3: Comparison of Total System Cost for the New England electric power sector in RPS and CES scenarios (in billion-$)

[2] This closely replicates the eligibility of technologies for RPS across the New England states. Maine is the only state which counts in-state hydro resource towards its RPS.

[3] Due to cost estimates for CCS technologies that have long been too optimistic, CCS technologies are only modeled to become available at their current cost estimates after 2030.

2.2. Electricity Generation

Currently, New England relies largely on natural gas and nuclear power for its electricity generation—over 78% of electricity in New England is generated by these two technologies (see Table 2). They also make up almost 67% of the net energy for load, with imports from New York and Canada making up an additional 16.7%.

Table 2: New England's resource mix in 2017 (ISO-NE 2018e)

	GWh	% of Generation	% of Net Energy for Load (NEL)
Total Generation	102,534	100.0%	84.7%
Gas	49,198	48.0%	40.6%
Nuclear	31,538	30.8%	26.1%
Renewables[4]	10,830	10.6%	8.9%
Hydro	8,572	8.4%	7.1%
Coal	1,684	1.6%	1.4%
Oil	696	0.7%	0.6%
Other	14	0.01%	0.01%
Net Flow over External Ties	20,243		16.7%
Québec	*14,401*		
New Brunswick	*4,306*		
New York	*1,536*		
Pumping Load	-1,716		-1.4%
Net Energy for Load	121,061		100.00%

A large transition of New England's electricity generation sector started around 2000. Environmental policies and, arguably more important, low natural gas prices, have pushed out coal and petroleum as the primary energy providers for electricity generation, and natural gas has largely taken its place. Between 2000 and 2016, oil fell from 8.2% to 0.5% and coal from 17.9% to 2.4%, while natural gas increased from 13.7% to 49.3% (see Figure 4).

[4] Note that 8.9% NEL of Renewables mainly include wind (2.7%), Refuse/Municipal Solid Waste (2.6%), and Wood (2.5%). Solar as the fourth-largest contributor provides 0.7%.

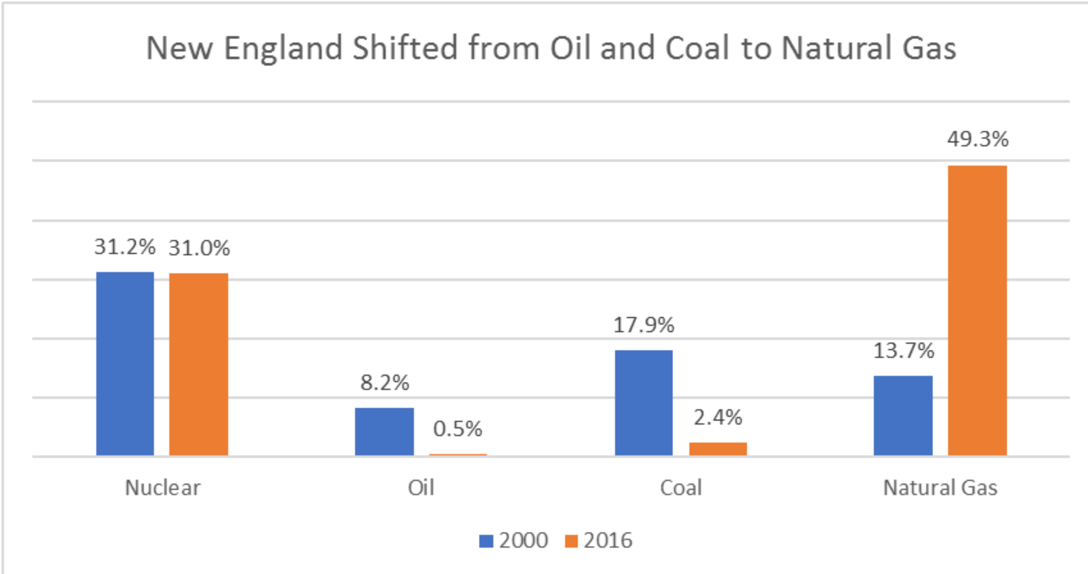

Figure 4: Shift from Coal & Oil to Natural Gas between 2000 and 2016 (ISO-NE 2018b)

The close ties of the electricity sector to the natural gas sector have proven difficult in recent winters, when prolonged cold temperatures hit the region and the demand for gas-fired heating increases (Babula & Petak 2014; Hibbard & Schatzki 2012; Wang et al. 2017) and competes with the demand for gas-fired power plants. The heating demand from utilities serving their customers is met with priority. At the same time, the demand for gas in the electric power sector also increases, as electric heating appliances are connected and increase electricity demand. As a result, during a cold spell gas plants face increased demand for gas, with decreased net supply capacity through the pipeline network due to prioritized utility gas withdrawals. For the electric power sector, this implies that other technologies that do not rely on gas are dispatched. In cold winter days these are increasingly coal and petroleum-fired power plants (ISO-NE 2018f). While this leads to a short-term increase in gas prices as well as electricity prices which hurt consumers, this is not a severe problem for the electric power sector as of now. Moving forward, it is crucial to monitor that either sufficient non-natural gas-fired power plants are in reserve capacity for a cold spell, or otherwise that pipelines into New England or LNG terminals are expanded accordingly to provide the necessary reserves for the electric power sector.

In these crucial times, the pipeline network of New England struggles to supply sufficient fuel due to its geographical location. With no natural gas wells in the region, it relies entirely on imports. Most of the natural gas imports come from New York state, and only a small amount from Canada, all through five pipelines feeding the region. The total pipeline capacity for the winter of 2024/25 was recently forecasted by ISO New England to amount to 3.86 billion cubic feet per day (Bcf/d)[5] (ISO-NE 2018f). In addition, three LNG terminals exist where liquified natural gas can be received from an ocean tanker and injected into the regional pipeline system. These three terminals have a joint-maximal capacity of 2.04 Bcf/d, even though the all-time recorded maximum injection per day was 1.25 Bcf (ISO-NE 2018f). Thus, New England has access to slightly less than 6 Bcf/d of natural gas. For a region which relies as much on gas-fired electricity production as New England, this is not a lot. This is the reason why periodic discussions center around expanding the pipeline capacities bringing fuel into New England. As mentioned above, from the standpoint of a systems planner this is something to be aware of, especially if the region has the ambition to engage in integrated energy and resource planning.

2.3. Opportunities for Low-Carbon Generation

To meet the challenge of decarbonizing the electric power sector, every region must make use of the resources at its disposal. The availability and quality of renewable resources like wind, solar, hydropower, or biomass vary strongly between regions. Some regions in the world, like Norway, Iceland and Costa Rica, already have almost completely decarbonized electric power sectors largely thanks to the coincidence that the most inexpensive electricity generating technologies in these countries are renewable sources. But other regions also need to assess their resources, and use tools like carbon pricing as well as CES and RPS policies which affect the merit order by favoring natural gas over coal-fired generation technologies (Delarue, Voorspools & D'haeseleer 2008), and enable the integration of renewable resources (Smith et al. 2007). Furthermore, regional integration is a very useful tool to share the benefit of location-specific natural occurrence of renewable resources.

Following this blueprint, New England needs to assess its own resources and its potential for regional integration with its neighbors. The renewable resource in New England with the largest potential installed capacity is wind generation, mostly in Northern and Western Maine. The Northern states, Maine, Vermont, and New Hampshire, all use biomass to a substantially larger degrees than the national average of the United States. This can be an important resource, especially if combined with CCS technology. Natural gas as a well-established resource in New England can also become a useful tool for its decarbonization efforts if natural gas generation is combined with CCS at high capture levels. Taking advantage of all of these resources across the region will require the expansion

[5] ISO New England discounts one of the pipelines, the Maritimes and Northeast pipeline between Canada and Maine, because under certain, not infrequent market conditions it will transport natural gas from New England into Canada.

of transmission capacities for electricity between load centers and the locations of generation resources.

New England must also look to regional integration efforts to access resources available in its neighbors' territories in New York and Canada. While stronger interconnection with New York can enable better synchronization of the two electricity markets and provide gains from trade, the more interesting connection is with the Canadian province of Quebec. Quebec's electricity generation is 95% hydropower, which is an excellent complement to the strongly thermal power sector in New England. Expanded interconnection capacity would be required to take fuller advantage of this resource. Taking better advantage of hydro from Canada can come on two forms: either through higher energy imports per year, providing more low-carbon electricity to the region; or through better allocation of the same annual amount of energy by using it purposefully in peak hours, when the value contributed to the system by hydro imports is greatest.

Wind is seen as one of the major contributors for electricity generation in the US in the 21st century, with projects evaluating the feasibility of long-range transmission lines transporting wind power from the Great Plains to the load centers at the East Coast (Frew et al. 2016). Similarly, wind power will play an important role in the future of New England's electric power sector (GE Energy, EnerNex Corporation & AWS Truepower 2010). Rather than relying on transmission from the Great Plains, New England can integrate wind resources from Maine into its electricity mix. Maine provides up to 69 GW of wind power potential, which is massive compared with 923 MW of currently installed capacity in the state (U.S. Department of Energy 2018). These resources are in relative proximity to load centers in Massachusetts and Connecticut. However, to unlock this potential renewable resource for the New England region, transmission grid expansions at the regional level need to be envisioned.

Natural gas has developed very strongly since the 2000s. And even currently, New England has large amounts of natural gas-fired power plants in its Interconnection Queue, which keeps track of all proposed projects that plan to connect to the electric grid in the future (ISO-NE 2018e). Furthermore, recent years have had strong discussions about pipeline additions into New England, as well as the addition of new LNG terminals. This is especially a recurring phenomenon every January or February, when a longer cold period hits New England. Other techno-economic power sector research suggests that natural gas can play a viable role on the path to 50-65% of emissions reductions in the electric power sector (Jenkins & Thernstrom 2017). However, New England's stated emissions goals are more stringent than these levels, and are at levels which are commonly associated with emissions reductions of over 90% in the power sector (Krey et al. 2014). There is a compelling storyline about the role of gas in a decarbonized power sector. This string of research focuses on the complementarity of the fast-ramping capabilities of natural gas with the intermittent nature of renewable sources like wind and solar (Lee et al. 2012; Paltsev et al. 2011), and therefore sees an important role for natural gas in the electric power sector even under decarbonization.

Biomass might be one of the key resources for any region on its path to a decarbonized power sector as it is dispatchable, and when paired with CCS even offers the opportunity to produce negative carbon emissions (Rhodes & Keith 2008). And in New England, biomass already is an established electricity generating technology. Maine has a share of 18.9% of electricity generated from biomass, New Hampshire 8.3%, Massachusetts 3.8% and Connecticut 2.3% (EIA 2017a). This is an outsized role compared to a national average of 1.1%. Nonetheless, there are some serious implications of biomass deployed on a large scale in the electric power sector. These can include inadvertent emissions increases through land-use change (Fargione et al. 2008), and carbon stock accounting over the lifecycle of the biomass which might end up not being carbon-neutral (Johnson 2009).

Another technology that needs to be considered as playing a potentially important role in New England's future electric power sector is carbon capture and storage (CCS) for coal or natural gas plants, if the technology becomes commercially viable and available. It currently faces a variety of technical, economic and public acceptance challenges. However, a crucial step by the U.S. government in early 2018 was the passing of a tax credit for CCS projects (Rathi 2018), which could provide the necessary push for the technology to be deployed in more than just pilot studies.

Finally, hydropower imports from Canada play a large role for New England. On average over the last five years, net imports from Canada were 17,483.2 GWh[6] (ISO-NE 2018e), which accounts for around 16% of the net load in New England. Over 75% of these imports come from Quebec, which also has the majority of interconnection capacity to New England. Quebec is connected to New England via the *New England Phase II* (1400 MW) and *Highgate* (200 MW) transmission lines. The electric power sector in Quebec is 95% composed of hydropower (see Figure 5), and one of my contributions in this thesis is to implement this techno-economic feature of New England's electric power sector in EleMod, the electricity capacity expansion model used in this work.

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[6] Steadily in between 16,700 and 18,700 GWh per year.

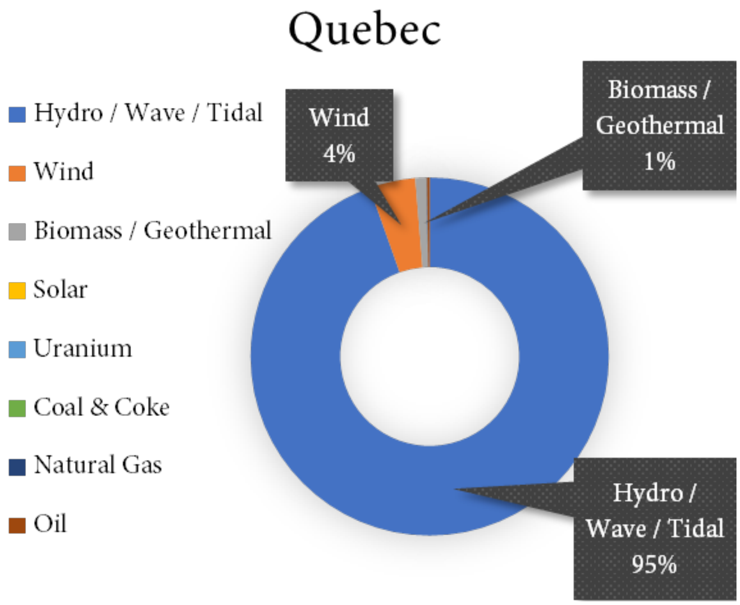

Figure 5: Quebec's resource mix (National Energy Board 2018)

Hydropower imports from Canada serve two purposes. First, they represent a low-carbon electricity source that could directly replace carbon-intensive generation. However, hydro imports do not currently qualify as counting toward most CES or RPS targets. Second, and the focus in my analysis, hydro imports have "peak-shaving" ability which can impact the evolution of the electric power sector. The management of reservoir hydropower installations is based on the value of stored energy (Simopoulos, Kavatza & Vournas 2007). To the extent that the release of water to produce electricity is not precluded due to other environmental factors and resource concerns[7], the energy from hydropower will be used to supply to the system when it needs it most, i.e. in the hours of highest prices. These hours mostly coincide with the peak of net demand (demand minus non-dispatchable generation), and thus the pattern of use for reservoir hydropower is also called "peak shaving", since it takes off the peaks and rather transforms them into plateaus (Bushnell 2003; Simopoulos, Kavatza & Vournas 2007).

Thus, hydropower is imported from Canada into New England to make use of surplus electricity stored in the Canadian reservoirs during hours of scarce supply, or high net load, in New England, thereby reducing the peak demand. As a result, hydropower imports into New England may result in

[7] The release of water from hydro reservoirs to generate electricity is subject to other constraints like river management and other water uses.

lower demand for total installed capacity for the electric power sector, and in lower dispatch of peaking technology resources, which are currently gas-fired power plants.

3. MODELING THE ELECTRIC POWER SECTOR

3.1. Decarbonization of the Electric Power Sector

Silberglitt et al. (2003) note that the diversity of technical, social and economic, as well as policy and regulatory characteristics have "led to the proliferation of energy scenarios" (Silberglitt, Hove & Shulman 2003). With decarbonization becoming increasingly more important in the combating of climate change, decarbonization scenarios are even more numerous today. There exist a myriad of models and approaches to capture decarbonization scenarios of the electric power sector. However, there is no clear classification in the research field of electric power sector modeling for decarbonization scenarios (Loftus et al. 2015). I start by reviewing a series of recent model comparison studies that were undertaken to illuminate recent developments in modeling efforts of decarbonization scenarios. The studies each analyze between three and 18 individual models that span a variety of classifications. Each model comparison study makes an attempt at classifying the models they examine, but they do not agree on one overarching typology. Nonetheless, some similarities are apparent in the classification schemes, and after review of the five studies I identify the three archetypes of energy system models that are most widely and successfully applied.

Capros et al. (Capros et al. 2014) explore costs for EU energy system transformation based on the EU Roadmap 2050 (80% GHG emissions reduction targets). They analyze decarbonization strategies, energy system restructuring, associated costs and further macroeconomic implications. All their considered models are widely applied large-scale models. They classify them into (1) partial equilibrium technology-rich energy system models, (2) energy models on specific sectors, (3) comprehensive computable general equilibrium models, and (4) macro-econometric models. The partial equilibrium energy system models focus on the representation of energy technologies, the engineering characteristics and economic markets. However, they do not provide feedback loops between the energy and other sectors of the economy. Macroeconomic models on the other hand display all sectors of the economy, while they lack more specific details of the technological systems of the energy sector (Capros et al. 2014).

Cochran, Mai & Bazilian (Cochran, Mai & Bazilian 2014) from NREL compare high penetration renewable energy scenarios from regions around the globe. The models they examine include both power sector and economy-wide models.

Krey et al. (Krey et al. 2014) report on the results of the Energy Modeling Forum (EMF) 22 by comparing all EMF participants' models. All models run a common set of scenarios, and the results are compared. The main way in which they differ are "decarbonization of energy supply, increasing the use of low-carbon energy carriers in end-use, and reduction of energy use" (Krey et al. 2014). They classify the models as either energy-economic or integrated assessment models (IAM). Also, they note that the major differences between the models in methodology lies in (1) the representation of the energy system, and (2) the CO_2 budgets that are made available to the model by the modelers.

Loftus et al. (Loftus et al. 2015) "assess a set of scenarios constructed using a diverse range of methods, including IAMs but also several other influential studies constructed using different methods" (Loftus et al. 2015). All their models focus on the decarbonization of the electricity sector, which makes it particularly relevant for my work. Their classification breaks models down into four groups: (1) top–down scenario-based back-casting, (2) top–down integrated assessment modeling, (3) bottom–up energy systems modeling, and (4) bottom–up techno-economic assessments.

Luderer et al. (Luderer et al. 2012) compare three models, two intertemporal optimization models as well as a recursive dynamic computable general equilibrium model. All three models are "hybrids" (Luderer et al. 2012), meaning they combine a top-down view of the economic sectors with a bottom-up view of technological details of the energy system.

Table 3: Model comparison studies analyzed to identify archetypes of models to simulate and inform decarbonization strategies

Authors	Title	Approach	Classification/typology
Capros et al. 2014	European decarbonisation pathways under alternative technological and policy choices: A multi-model analysis	Seven large-scale energy-economy models[8]	partial-equilibrium and macroeconomic models
Cochran et al. 2014	Meta-analysis of high penetration renewable energy scenarios	Twelve models with 80 – 100% of RE penetration	Power sector and economy-wide models, among them hourly dispatch, capacity expansion
Krey et al. 2013	Getting from here to there – energy technology	18 models running similar scenarios with	Energy-economic and integrated assessment models

[8] PRIMES, TIMES-PanEu, GEM-E3, NEMESIS, WorldScan, Green-X and GAINS

	transformation pathways in the EMF27 scenarios	decarbonization of energy supply, increasing the use of low-carbon energy carriers in end-use sectors, and reduction of energy use	
Loftus et al. 2015	A critical review of global decarbonization scenarios	Eleven studies (17 scenarios) constructed using a diverse range of techniques	Top–down scenario-based back-casting; top–down integrated assessment modeling; bottom–up energy systems modeling; and bottom–up techno-economic assessments
Luderer et al. 2012	The economics of decarbonizing the energy system	Three models compared[9] in the RECIPE model comparison	quantitative energy-economy-climate models: (1) intertemporal optimization, (2) recursive dynamic computable general equilibrium

As archetypes, three distinct types emerge: (1) IAMs encompass the highest level of top-down, inclusive models that can include a wide range of causes and show system-wide effects; (2) detailed techno-economic energy system models focus on the technical aspects of the energy and/or electricity system; and (3) hybrid models combine bottom-up and top-down approaches in an attempt to find a better trade-off between the strengths and weaknesses of the other two model types. For the purposes of my work, since my research question is aimed at the electric power sector, the second type of model is most appropriate.

3.2. Capacity Expansion Planning

Emerging from the literature review in Section 3.1, I reviewed a list of nine techno-economic electric power sector models. In this section, I present the results from this literature review (see Table 4). It becomes apparent from the analysis that Capacity Expansion Planning models are the most applied type of model. Seven of the nine reviewed models are CEP models, and I choose to conduct my analysis using a Capacity Expansion Planning model as well.

Two model characteristics are of high importance for my analysis: an hourly scope for solving the energy balance equations, and a representation of long-distance transmission. The hourly resolution is highly preferable to a collection of time slices to fully capture the supply-demand dynamics with intermittent renewables. And since the focus of my thesis is to explore scenarios of transmission and

[9] ReMIND-R, WITCH, IMACLIM-R

interconnector expansion, having a representation of transmission between regions is necessary for my analysis.

However, many of the reviewed models do not include these two features. In many cases, models use time slices which group the hours of the year into characteristic groups based on time of day and seasonality. The representation of long-distance transmission is only included in four of the reviewed models.

For my thesis, I thus choose the capacity expansion planning model EleMod, which I introduce in the following chapter. The model meets the shortcomings of a large list of the reviewed models. It solves an hourly dispatch model to adequately capture the challenges of intermittent resources. Furthermore, EleMod can be applied to the geographic scope of New England, and it allows for the representation of transmission interfaces in between states. Finally, a hydro resource in Canada can be added to the model which allows the assessment of the benefit of hydropower imports and the effect of increased interconnection capacity.

Table 4: Overview of Bottom-Up Electricity Sector Models

Model Name	Model Type	Reference	Description	Technological Scope	Temporal Scope	Cost Parameters	Modeling Highlights
AURORAxmp	Dispatch optimization, capacity expansion	Carley 2011	State energy portfolios, resource dispatch based on competitive wholesale	Individual plant data from EIA	Every fourth hour, four days a week on alternating weeks	Real levelized net present value (in $/MW) of all available resources	Electricity market prices, realistic transmission capacity constraints
Renewable Energy Flexibility (REFlex)	Reduced-form dispatch model	Denholm et al. 2012	REFlex is a reduced form dispatch model that compares the hourly demand for electricity with the supply of renewable energy considering grid constraints	Wind, PV, CSP and nuclear with 8h thermal storage, conventional resource portfolio	Hourly load data from ERCOT	Variable cost of generation	Combining renewable and nuclear energy using thermal storage
European Unit Commitment and Dispatch (EUCAD)	Hourly dispatch optimization	Després et al. 2017	Integrates with POLES model which accounts for capacity expansion planning	Wind, solar, storage, conventionals	Hourly	Variable costs	Storage technologies, demand response, and European grid interconnections
Regional Energy Deployment System (ReEDS)	Capacity expansion and dispatch model	Eurek et al. 2016	Built for the contiguous United States, explores generation and transmission capacity expansions	Focus and detail of renewables (on- and off-shore wind, solar CSP and PV, geothermal, biopower, kinetic wave), also conventional fleet, storage, demand-side response, energy efficiency	17 time slices	Energy and capacity costs	Complete technology set, endogenous transmission expansion, CES and RPS
Renewable Energy Mix (REMix)	Capacity expansion, hourly dispatch	Gils et al. 2017	Assess the capacity expansion and hourly dispatch at various levels of photovoltaic and wind power penetration	Solar PV and CSP, wind, hydro run-of-river, storage, thermal plants (geothermal, biomass, conventional fuels)	Hourly	Capital costs and operational costs	Deterministic optimisation of the operation and the capacity expansion of all

Model Name	Model Type	Reference	Description	Technological Scope	Temporal Scope	Cost Parameters	Modeling Highlights
							modelled technologies
LIMES-EU	Capacity expansion, hourly dispatch	Haller, Ludig & Bauer 2012	Multi-scale power system model to explore expansion pathways for renewables, long distance transmission and storage capacities	Focus and detail on renewables, but also conventional resources	49 time slices	Investment, fixed and variable O&M costs	Long-term transmission, storage
(No name)	Capacity expansion, hourly dispatch	Jägemann et al. 2013	Dynamic linear electricity system optimization model for Europe	Conventional, CHP, nuclear, renewables, storage	Four typical days per year, investment decisions every five years	Investment, fixed O&M, variable costs, and ramping costs	High technological and regional resolution
MARKAL UK	Perfect foresight partial equilibrium optimization model	Kannan 2009	Minimizes discounted total system cost by choosing the investment and operation	Conventional, CHP, solar PV, on- and off-shore wind, biomass, wave energy	6 time slices (night + day, 3 seasons)	Capital cost, fixed and variable O&M	Technology-rich (including CCS), learning rates
Investment Model for Renewable Electricity Systems (IMRES)	Advanced generation capacity expansion model	Sisternes, Jenkins & Botterud 2016	Generation capacity expansion model with detailed unit commitment	Focus on solar, also advanced nuclear, advanced coal, combined and open cycle gas turbines	Hourly	Annualized fixed costs, variable operating costs	Value of storage, unit commitment constraints and investment decisions for individual power plants

4. ELEMOD: A CAPACITY EXPANSION PLANNING MODEL

EleMod is a recursive-dynamic optimization model that solves capacity expansion, generation planning and dispatch on an hourly basis over the time horizon of thirty years. The capacity expansion function of the model is jointly executed with the generation planning and dispatch functions by examining how to meet the hourly demand profile of the given year. Slightly simplified, operation planning accounts for the daily start up and shutdown decisions of the different generation technologies, operation dispatch considers the hourly economic dispatch decisions of the various technologies based on the variable costs (fuel and variable O&M costs) as well as the costs associated with specific start-up and shut-down sequences, and capacity expansion planning decides which new capacities to add to the system based on the technologies' annualized costs (annualized fixed capital costs and O&M costs) and long-term reliability requirements. For a more detailed description of the mathematical formulation of EleMod, please refer to Tapia-Ahumada et al. 2014 and Tapia-Ahumada et al. 2015.

EleMod was developed as a techno-economic model to study the electric power sector for the lower-48 US states and Alaska. In this configuration, states were aggregated into 12 larger regions, with New England as one of those regions. Given the modular framework of the model, its structure can be applied to study other geographical areas. To answer the research question set out for my thesis, I thus use EleMod and adapt its structure to study the New England electric power sector in detail, where the regions are now the six New England states.

The contributions of my work to the research efforts around the development of EleMod at the MIT Energy Initiative and the Joint Program on the Science and Policy of Global Change include the following features: First, I added a representation of hydro imports from Canada (see subsection 4.2.2). Second, I included a representation of the transmission interfaces within New England (see subsection 4.2.3). And third, I added a Clean Energy Standard which enforces a certain percentage of each year's generation to come from a set of CES-eligible technologies.

4.1. Core Structure of EleMod

4.1.1. Technologies

The choice of generation technologies was primarily based on the latest data of NREL's 2017 Annual Technology Baseline (ATB). Its officially stated purpose is "to provide CAPEX, O&M, and capacity factor estimates for Base Year and future year projections […] for use in electric sector models." (NREL 2018) Most of the technologies included in my analysis are taken from there. These include three technologies for natural gas (combustion turbine, combined-cycle, and combined-cycle with CCS), three coal technologies (a state-of-the-art coal plant, one with 30% CCS and one with 90% CCS), nuclear power, hydropower, wind (land-based) and solar power (utility-size), as well as two biomass technologies (a dedicated and a co-fire plant). In the following subsection 4.1.2, I provide details on the operational characteristics and investment cost data for these plants.

Since the ATB is directed towards future deployment of electricity generating technologies, it does not contain data for some of the legacy technologies like petroleum-fired plants, steam-powered open cycle gas plants, or old coal plants. While I do not allow capacity expansion for these technologies, their current stock is not negligible: New England possesses over 7 GW of oil-fired plants, over 4 GW of old coal plant, and over 1 GW of open cycle gas plants. I thus choose four technologies based on the 2006 EIA AEO to represent these legacy plants: an oil/gas steam turbine, a coal steam plant, a petroleum steam turbine and a petroleum combustion turbine. A full overview of all 17 generation technologies available in EleMod for my study can be found in Table 5.

Table 5: EleMod Generation Technologies

Code	Resource	Technology
n01	Natural gas	Natural gas combustion turbine — GasCT
n02		Combined cycle gas turbine — GasCC
n03		Combined cycle gas turbine with carbon capture and sequestration (CCS) — GasCCS
n09		Oil/gas steam turbine — OGS --> Assumed to use GAS
n05	Coal	Conventional pulverized coal steam plant (with SO2 scrubber) — CoalOldScr
n06		Advanced supercritical coal steam plant (with SO2 and NOx controls) — CoalNew
n07		Integrated gasification combined cycle (IGCC) coal — CoalIGCC
n14		Coal-CCS-30%
n15		Coal-CCS-90%
n10	Nuclear	Nuclear plant — Nuclear
n12	Biopower	Advanced supercritical coal steam plant (with biomass cofiring) — CofireNew
n13		Dedicated biomass plant – Dedicated
n16	Petroleum	Oil Combustion Turbine
n17	Petroleum	Oil Steam Turbine
Solar	Solar	Solar power (utility scale)
Wind	Wind	Wind power
Hydro	Hydro	Run-of-river Hydropower

4.1.2. Cost and Operational Parameters

The cost and operational parameters used in EleMod are shown in Table 6. The relative costs of all technologies can be found in Appendix B (conventional resources) and C (renewable resources). To better understand how the cost and operational parameters are used in the model, I divide them into three groups: parameters used (1) in calculating the energy balance, (2) in determining the capacity expansion, and (3) in minimizing the cost function.

All the parameters in Table 6 are directly taken from the ATB database, with exception of the annualized and fixed capacity costs (*fca*), which is based on other data from ATB. This value is crucial to determining the capacity expansion decisions in the model, and represents the annualized investment costs of the model:

$$fca = (oncap + \ fin) * cfr + fom$$

Where
fca fixed cost (annualized)
oncap[10] overnight capital cost
fin financing cost
cfr capital recovery factor
fom fixed O&M cost.

The data for cost parameters used in EleMod was previously supplied from the EIA AEO in 2006 and 2016. I supply data for cost parameters with the latest values from the NREL's 2017 ATB (NREL 2018), [11] which largely draws on the equivalent 2017 AEO outlook data. The advantage of the ATB is the consistent presentation of data for all new generation technologies in an easy-to-integrate Excel table.

Table 6: Cost and Operational Parameters for Technologies

Code	Cost parameter	Unit	Function	Source
pmin	minimum plant loading	%	Energy balance, long- and short-term reserves	NREL ATB
af	availability factor	(p.u.)	Energy balance, long- and short-term reserves	NREL ATB
orfr	forced outage rate	(p.u.)	Energy balance, long- and short-term reserves	NREL ATB

[10] The parameters *oncap*, *fin*, *cfr*, and *fom* are obtained from the ATB for all technologies (*cfr* does not vary by technology).

[11] Only exception are the legacy technologies. To find appropriate cost and performance parameters, I went back as far as possible to the 2006 EIA AEO outlook. My assumption is that plant data from 2006 provide the most accurate representation of the operational characteristics of those legacy plants.

fca	fixed cost (annualized)	$ per kW per year	Capacity expansion	Own calculation based on other NREL ATB data
vom	variable O&M cost	$ per kW per year	Capacity expansion	NREL ATB
eclf	economic life time	Years	Capacity expansion	NREL ATB
stupcost	start-up cost	$ per kW	Cost	NREL ATB
pf	base fuel price	$ per MMBtu	Cost	NREL ATB
hr	electric heat rate	MMBtu per kWh	Cost	NREL ATB
ef	CO2 emission factor	Metric ton per MMBtu	Cost	NREL ATB

4.1.3. Temporal Scope

EleMod conducts an hourly representation of dispatch and daily operation planning. The capacity expansion planning is done on an annual basis, and volumes of newly installed capacity are carried over to form the base stock in the next year.

In order to save computational time but enable an outlook further into the future, I solve the capacity expansion every four years starting in 2018 and going out to 2050. These nine snapshots of annual capacity investments as well as year-long generation profiles on an hourly basis provide a forecast to analyze the future of New England's electricity sector.

4.1.4. Objective Function

For the objective function, EleMod offers two options: (1) to minimize the total system cost over all regions, or (2) to maximize total welfare. Total system costs include the annualized investment costs and fixed operation and maintenance (O&M) costs, start-up and shut-down costs for generators, and variable costs. The latter include variable O&M costs, fuel costs based on heat rate, fuel prices, and generation levels, as well as the cost of non-served energy (NSE), which accounts for the cost to society of not serving load based on the Value of Lost Load (VoLL).

$$TotCost = \sum_{reg} TCost_{reg}$$

Where
TotCost Total System Cost
TCost System Cost per region
reg Set of regions of the model.

And for every region:

$$
\begin{aligned}
TCost_{reg} = & \sum_{tech} ICap_{reg,tech} * fca_{tech} + \sum_{tech,h} StUp_{reg,tech,h} * stupcost_{tech} \\
& + \sum_{tech,h} GOut_{reg,tech,h} * (fuel_{tech} * \ heatrate_{tech} + \ CO2_{reg} * emiss_{tech} \\
& * heatrate_{tech} + \ vom_{tech}) + \sum_{tech,h} \left(CPow_{reg,tech,h} - GOut_{reg,tech,h}\right) * vom_{tech} \\
& + \sum_{h} NSE_{h} * VoLL
\end{aligned}
$$

Where

ICap	Installed capacity per region and technology
StUp	Start-up variable per region, technology and hour
Gout	Electricity output per region, technology and hour
CPow	Connected power per region, technology and hour
NSE	Non-served energy demand per hour
fca	Annualized fixed capacity cost per technology
stupcost	Start-up cost per technology
fuel	Fuel price per technology
heatrate	Heat rate per technology
CO2	CO_2 price per region
emiss	Emissions rate per technology
vom	Variable O&M cost per technology
VoLL	Value of Lost Load.

As an alternative, the welfare maximization computes consumer and producer rents based on the hourly electricity prices and subtracts total system costs. The calculation of rents is non-linear and requires the use of a Quadratically Constrained Programming (QCP) solver. For this work, I apply the cost minimization described above which can be solved using Mixed-Integer Programming (MIP).

The main decision variables for EleMod are annual installed capacities per technology and region (for the capacity expansion), hourly generated power per technology and region (for dispatch planning), the connected power on a daily basis (operational planning), the hourly system curtailments for wind and solar power per region, and the hourly NSE per region.

The major constraints of the model include the resource availability for additional capacity installments of solar and wind power per region, the reserve margins for short-term operational reserves, the reliability requirements for long-term security of supply, and the minimum and maximum generation levels per technology which are relevant for the operation and dispatch planning. The equations for the latter model features can be found in (Tapia-Ahumada et al. 2015).

4.1.5. EleMod Data

The strengths of a bottom-up techno-economic model lie in its ability to capture technological processes and market mechanisms in mathematical relationships. But in order for the solutions to these formulas to develop a real meaning, they need to be built upon reliable data, and in many cases a lot of it.

This is also the case with EleMod. Since I build my model upon an earlier version of the model, many data sets already exist and can be applied to my model as well after some data processing. As a first principle, if data that is available from the twelve-region version of EleMod on a state- or even more disaggregated level, I simply re-do the aggregation process and stop at the state-level rather than the New England regional level. In cases where data for EleMod is directly supplied for the New England region without further disaggregation, I choose either of three options: apply the regional value to each state, use reasonable assumptions to break up the regional data into state-level data, or if neither of these approaches is feasible, I supply data from new sources. For the latter approach, refer for example to the existing nameplate capacities (see Section 4.2.1) and the transmission interfaces (see Section 4.2.3).

Three of the most important data elements are already described above: the set of 17 technologies, the existing nameplate capacities per technology and state, and the cost and operational parameters. The transmission interfaces follow below in section 4.2.3. Following here, I thus explain more in detail the performance and cost parameters and the load profiles.

The annual load profile is based on an actual load year case, which is available from ISO-NE (ISO-NE 2018a). This hourly wholesale load data is parametrized to represent shares of the annual load for each hour. It is then recombined in each year with the total energy demand for New England, which is updated by accounting for demand increases based on AEO data projections (EIA 2016).

It is important to note at this point that AEO projections are not in line with electricity demand growth which we would expect at least in the deep decarbonization scenarios. Until mid-century, electricity demand is only projected to increase by around 33%.

4.2. Model Contributions

In this section, I describe my own contributions to the development of EleMod. First, I adapted the regional scope to cover New England (see Subsection 4.2.1). Since New England is highly interconnected with Canada and relies on imports from Quebec for around 16% of its annual load, I also include the representation of a hydropower reservoir which is available to the New England electric power sector based on the capacities of cross-border transmission lines. Third, I develop a representation of the long-distance transmission system in New England based on capacities of the transmission interfaces (see subsection 4.2.3). Since EleMod includes available wind resources per state, and the largest wind resources in Maine are far away from the load centers in the greater Boston area and Southern Connecticut, modeling the constraints of the long-distance transmission grid adds value to my analysis. And finally, I employ a CES requirement to incentivize the building of renewable generation capacity.

4.2.1. Representation of New England Power Sector

To create a representation of the New England power sector in EleMod, most of my work consists of data collection and data processing. After adding six regions as the geographical scope of EleMod, one for each New England state, the most important input data are the previously installed capacities per generation technology per state. Starting from NREL's Annual Technology Baseline as the list of generation technologies that are relevant to consider in my capacity expansion analysis (including the legacy technologies), I match all 17 technologies with the recorded installed generation units from EIA's annual generator-specific electric power sector survey Form EIA-860 (EIA 2017b). The EIA data is a trusted and high-quality source for accurate nameplate capacities, but the categorization of technologies does not overlap entirely with the NREL ATB. Thus, to ensure a mutually exclusive and collectively exhaustive matching of the two technology lists, I make the following decisions (see Appendix A for a complete overview in table form).

For EIA technologies with nameplate capacities that were divided between two NREL ATB technologies:

- I divide Conventional Steam Coal (EIA Form 860) capacities between CoalOldScr (legacy, NREL ATB) and Coal-new (NREL) based on plant operating year (<1990 for CoalOldScr, and >1990 for Coal-new). The same criterion is used by the NREL ReEDS model (Short et al. 2011).
- I divide Petroleum Liquids (EIA) capacities between Oil Combustion Turbine (legacy, NREL) and Oil Steam Turbine (legacy, NREL) by computing nameplate capacities depending on prime mover code ("ST" for Steam Turbine, and all others for Combustion Turbine).
- I divide Wood/Wood Waste Biomass (EIA) capacities between CofireNew (NREL) and Dedicated (biomass, NREL) depending on the listed secondary fuels (if any non-renewable secondary fuel exists counted for CofireNew, otherwise for Dedicated).

The nameplate capacities of other EIA technologies were aggregated to provide the existing installed capacity of an NREL ATB technology:

- I aggregate Municipal Solid Waste (EIA) and the above specified portion of Wood/Wood Waste Biomass (EIA) to provide nameplate capacities for CofireNew (NREL).

Finally, I discard these EIA technologies because their cumulative capacities were insignificant (<0.25%):

- Landfill Gas
- Natural Gas Internal Combustion Engine
- Offshore Wind Turbine

After matching the 17 NREL ATB-based technologies with their corresponding set of generators from EIA Form 860 data, I compute the cumulative nameplate capacity for each EleMod technology to obtain the input data table for previously installed capacities (see Table 7).

Table 7: Previously installed capacities for EleMod per technology and per state (in GW)

EleMod Code	EleMod Name	CT	MA	ME	NH	NY	RI	VT
n01	GasCT	0.5187	0.4027	0.3541	0.005	3.8477	0	0
n02	GasCC	2.8527	6.2567	1.3886	1.3955	9.6013	1.9607	0
n03	GasCCS	0	0	0	0	0	0	0
n04	CoalOld	0.4	1.1246	0	0.5592	1.8467	0	0
n06	CoalNew	0	0	0	0	0.003	0	0
n07	CoalIGCC	0	0	0	0	0	0	0
n09	OGS	0.3805	0.2115	0.0155	0.414	9.836	0.0104	0
n10	Nuclear	2.1629	0.67	0	1.242	5.7081	0	0
n12	Co-fire	0.0346	0.1079	0.6718	0.07	0.2588	0	0.0609
n13	Biomass	0.2146	0.2056	0.2044	0.1874	0.2014	0	0.0215
n14	CoalCCS30	0	0	0	0	0	0	0
n15	CoalCCS90	0	0	0	0	0	0	0
n16	OilComb	1.452	1.0457	0.0526	0.103	2.0785	0.0124	0.1329
n17	OilSteam	1.3648	2.2858	0.865	0.007	1.8036	0.004	0
Wind	Wind	0.005	0.0964	0.8988	0.1853	1.8288	0.021	0.121
Solar	Solar	0.0252	0.4836	0	0	0.1103	0.0102	0.066
Hydro	Hydro	0.1185	0.2689	0.7148	0.4248	4.6777	0.0028	0.3274

Furthermore, I update a series of data inputs like potential wind resources for each state and the values for operational reserve requirements. If applicable, as for the latter, I use the value for the New England region for each of the six states. In other cases, such as wind resources, the EleMod input was originally aggregated to provide data for the twelve regions. With some computational commands, I am thus able to provide the aggregation data per state rather than per New England region. And as a third option, such as in the case of previously installed capacities, I provide a completely new data set as input.

4.2.2. Canadian Hydro Reservoir

To appropriately reflect the real-world constraints on the availability of the hydro imports from Canada, I apply an hourly limit for power transfers which represents the cross-border transmission capacities between Canada, Vermont, and Maine (see below):

$$\boldsymbol{imp_{reg,h} \leq linecap_{reg}}$$

Where
imp hydropower import per region per hour
linecap total capacity of transmission lines to Canada per region.

Furthermore, I restrict the total available energy over the entire year to the average amount of annual imports from Canada into New England over the last five years:

$$\sum_{reg,h} imp_{reg,h} \leq hydroener$$

Where
imp hydropower import per region per hour
hydroener total energy from hydropower imports available annually.

One drawback of the approach is that the costs for hydropower imports are not directly included in the objective function. This means that the allocation of hydropower across the hours of the year is done strictly based on maximum value that the energy can provide to the system in each hour by reducing the generation from other resources. This would be a correct representation, were it not for the fact that New England customers must pay the power producers in Canada, namely Hydro Quebec, for the resources. This payment will be at the New England wholesale electricity price. In fact, in this way the costs of hydropower imports can be tracked through EleMod. The model reports locational marginal prices (LMPs) for every state and for every hour. Thus, the hourly import flows on each of the interconnectors to Canada can be summed up, multiplied by the LMPs in the state that is importing. I will use the ex-post calculation of hydropower import costs in my analysis to offset some of the decreases of total system costs that expanding the interconnection lines provide.

This is a simple, yet effective approach to model the impact of hydropower imports on the electric power system. There are certainly improvements that can be made to represent the linkage of hydropower between Canada and New England. One example would be to keep historic reference prices for the Canadian electricity markets in Quebec and the Maritimes provinces to decide based on price differentials between marginal prices in the New England EleMod regions and the Canadian reference prices whether hydropower is available for import into New England, and how much the costs of imports are. However, for this first inclusion of hydropower imports from Canada into EleMod, I maintain this simple solution as it closely replicates the market mechanisms of allocating import energy where it can provide most value to the system.

Representing hydropower imports from Canada is not only relevant for New England but would potentially also play an important role for similar modeling approaches for New York, or for the Pacific Northwest states which are connected to British Columbia, the other Canadian hydro powerhouse. Certainly, adding hydropower potential for import during scarcity hours, as is done in practice, would be a valuable addition to modeling the United States electric power sector with the original, twelve-region version of EleMod.

4.2.3. Transmission Grid Representation

The transmission system is one of the most complex components of the electricity sector. Moreover, in decarbonization scenarios transmission grid expansion is expected to be a key factor (Becker et al. 2014; Fürsch et al. 2013; Haller, Ludig & Bauer 2012). Thus, I incorporate transmission interface constraints for power transfers between regions into EleMod.

When talking about transfer capacities for electric power between the New England states, it is important to understand that in a meshed transmission network, precise capacities between location A and location B cannot be specified. Rather, based on empirical results we can identify a transmission interface which represents the border between two regions that experience limited transfer capabilities at times (Hogan 1993).

Table 8: New England transmission interfaces

Interface	CT.MA	MA.NH	ME.NH
Current capacity (GW)	2.500	3.400	1.475

For New England, the most important transmission interfaces are depicted on the map in Figure 6. Since EleMod is divided into states, I implement all the transmission interfaces which are located along state borders, and I neglect intra-state transmission interfaces. Thus, I model the Maine-New Hampshire interface, the North-South interface between Massachusetts and New Hampshire, and the Connecticut Import interface. Furthermore, to reflect transmission capacities on state borders that do not coincide with a transmission interface, I include in the model transmission interfaces with very large values between Massachusetts and Rhode Island, as well as Vermont and New Hampshire. For the purposes of the transmission analysis, these states are considered a joint region.

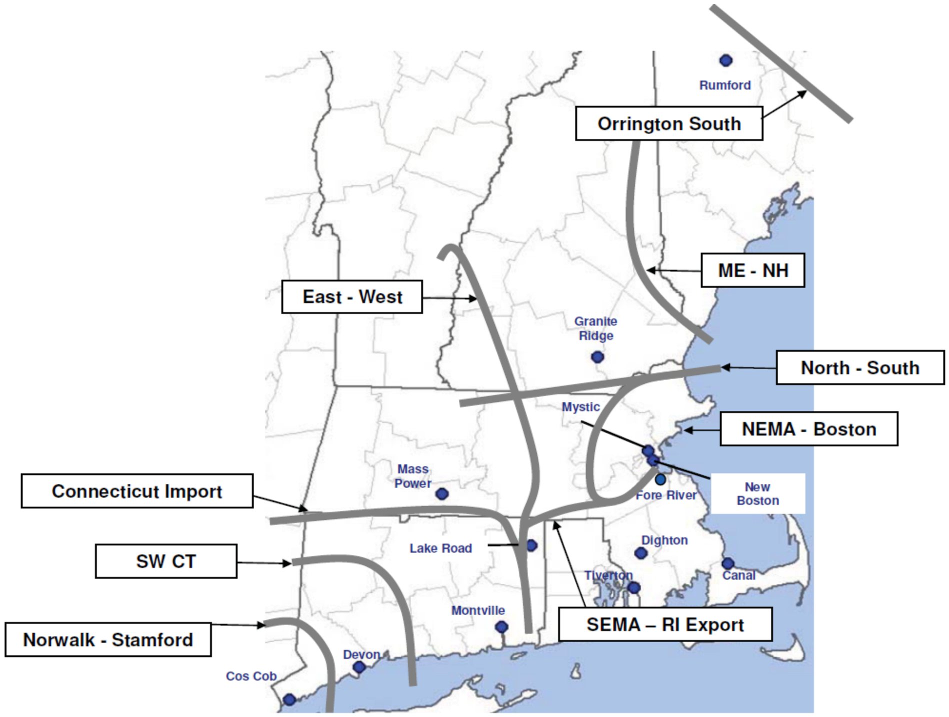

Figure 6: NE Transmission Interfaces (Charles River Associates 2010)

One improvement that can be done to the model in order to make the transmission interfaces interlock better with the regional borders is to use the ISO-NE load zones as regions, instead of the states. These are basically the state boundaries, but Massachusetts is split up into Northeastern (Boston), Southeastern, and Western/Central Massachusetts. Thus, all but the East-West, Southwest Connecticut and the Orrington South interfaces can be modeled. This would also require the installed generators to be divided up into the three parts of the state, which could be done since generator data is linked to counties, which can be linked to load zones.

4.2.4. Clean Energy Standard

Finally, I include in EleMod a representation of Clean Energy Standards, based on the RPS commitments that New England have made. The mathematical formulation is straight-forward, summing the CES-eligible generation technologies' output, and making sure it is greater than the renewable portfolio standards for all six states together:

$$\sum_{reg,tech_{CES},h} GOut_{reg,tech_{CES},h} \geq \sum_{reg,h} CES_{reg} * ener_{reg,h}$$

Where

GOut	generation output per technology, per state and per hour
CES	clean energy standard per state
ener	energy load per region and per hour
$tech_{CES}$	set of technologies eligible for CES

The technologies which are eligible for the CES in EleMod are wind, solar, hydro from Maine[12], biomass, GasCCS and CoalCCS.

One obvious limitation to the representation of the CES in EleMod is the fact that New England states currently deploy RPS. However, I precisely aim to show that CES can be an interesting policy tool that enables decarbonization up to 95%. Moreover, the model representations does not exclude municipalities serving as utilities from having to fulfill the requirement, as is done in practice. In most states the portion of generation excluded is very small (< 3%), but in Massachusetts 14% of the generation is procured by utilities that fall under the exemption. In effect, this strengthens the CES in the model compared to the current RPS in practice. Furthermore, I do not replicate different classes of energy credits based on the specific requirements that the states lay out. Computationally, this would not be difficult to implement, but the benefit for the long-term analysis undertaken with EleMod is only limited. But the definitions for which resources are eligible for a CES, or an RPS, tend to change over time. Connecticut for example recently committed to changes which will, over 15 to 20 years, make biomass plants only eligible for up to 50% of their produced energy.

[12] This is modeled after the Maine RPS rules.

5. SCENARIOS

The twelve cases which I will analyze are shown in Table 8. The Reference Case (*TransRef*) explores the six New England states with current levels of installed capacities, existing transmission capacities, and CES commitments based on the RPS that are currently in place. Then, in one dimension of the analysis I variate the CES by increasing the projected trajectories (see section 5.1). In the other dimension, I increase transmission capacities in between New England states, and on the border with Canada (see section 5.2).

Table 9: Overview of model scenarios

		CES SCENARIOS		
		CESbase	**CEShigh**	**CESdecarb**
TRANSMISSION SCENARIOS	**Reference Case with reference transmission (*TransRef*)**	*TransRef with CESbase*	*TransRef with CEShigh*	*TransRef with CESdecarb*
	Unlimited transmission within New England (*TransNEngl*)	*TransNEngl with CESbase*	*TransNEngl with CEShigh*	*TransNEngl with CESdecarb*
	Unlimited interconnection on border with Canada (*TransCan*)	*TransCan with CESbase*	*TransCan with CEShigh*	*TransCan with CESdecarb*
	Unlimited transmission for all (*TransAll*)	*TransAll with CESbase*	*TransAll with CEShigh*	*TransAll with CESdecarb*

5.1. CES Scenarios

The *CESbase* scenario represents the commitments that New England states have made so far (see Figure 7). I developed the *CEShigh* scenario by building off Massachusetts' indefinite commitment to increasing the CES by 1% annually, presumably until the issue is revisited at a point in time in the future when the grid or other considerations of the state's and the region's decarbonization strategy require an interference with this trend in either way. For Connecticut, my assumption is based on Governor Dannel P. Malloy's plan to reach 75% of clean energy, put forth in his State of the State address in 2018 (The Office of Governor Dannel P. Malloy 2018). While the governor specified 75% of all energy by 2030, I take a more gradual approach and assume 75% of electricity generation by 2050. Vermont remains on the path they officially committed to, which is to reach 75% in 2032. Rhode Island and New Hampshire did not publish specific plans to increase their CES, so they are taken under the same policy as Massachusetts, to grow their CES 1% annually once they hit their current target (see Figure 8). Finally, for the *CESdecarb* scenario I increase all states' CES requirements gradually to 95% to promote the decarbonization of the electric power sector (see Figure 9).

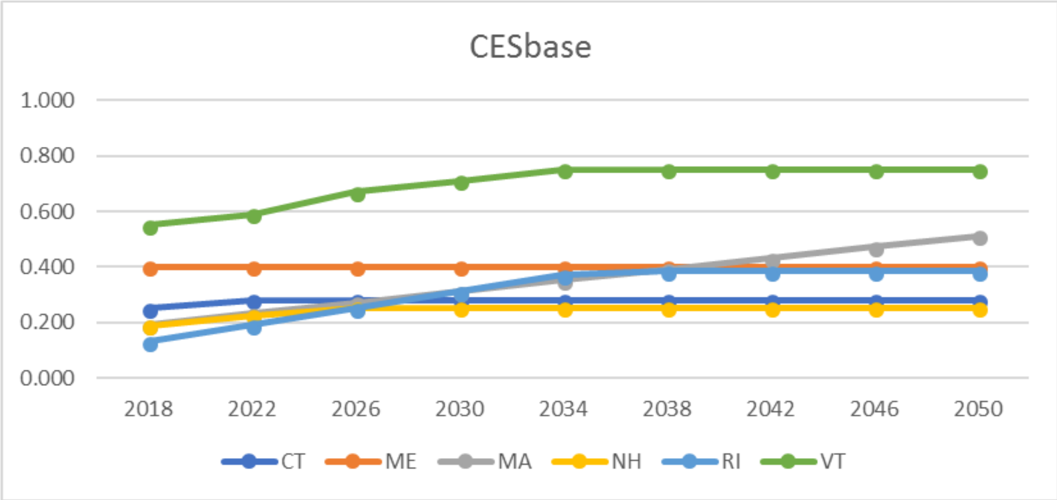

Figure 7: Renewable portfolio standards for CESbase scenario

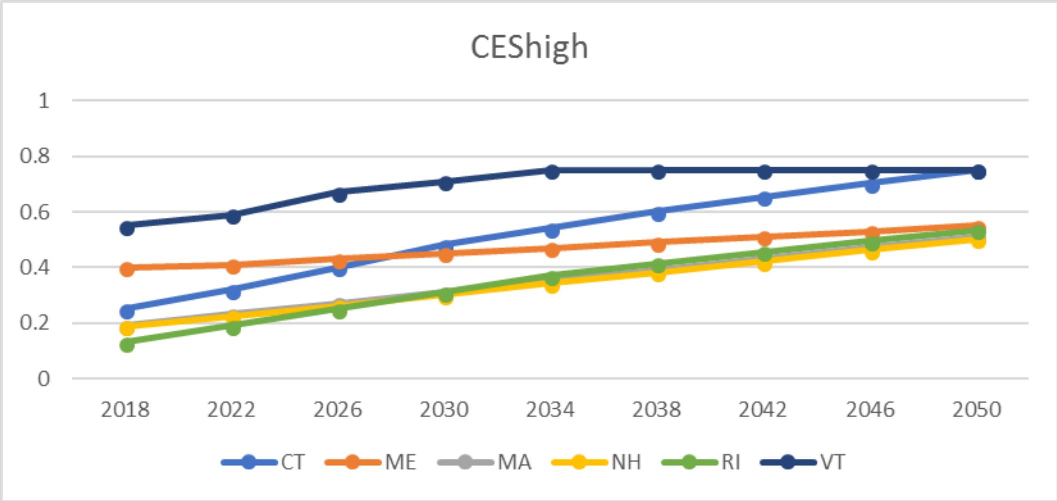

Figure 8: Renewable portfolio standards for CEShigh scenario

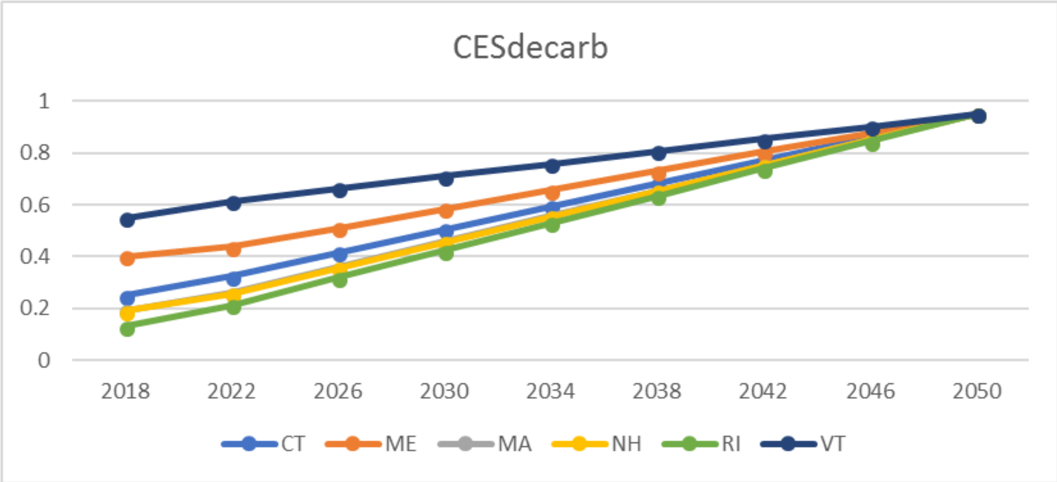

Figure 9: Renewable portfolio standards for CESdecarb scenario

5.2. Transmission Scenarios

The closer linking of New England with its neighboring states, especially the Canadian provinces to the North, has been the subject of extensive public discussion. On the one side, New England politicians, especially in the load center states of Massachusetts and Connecticut, aim for lower electricity prices through imports of cheap hydropower from Canada. Also, the addition of more renewables in the North, be it through hydro imports or more connected wind power in Maine, is desirable as states aim to reduce their greenhouse gas emissions.

In my study, I deploy three alternative scenarios beyond the *RefTrans* scenario: First, I expand transmission capacities within New England to a very high degree, such as to avoid any congestion on the network. This is the “copperplate” approach. My hypothesis is that this configuration will allow more wind capacity to take advantage of the pressure applied by the CES, especially in the *CEShigh* and *CESdecarb* scenarios.

A second scenario which I prepare is to increase transmission capacities on the cross-border interconnectors to Canada, such that the allocation of hydropower imports can be targeted specifically to the hours with highest net demand, and highest locational marginal prices, thus maximizing the value captured from the integration of Canadian hydro in New England. This scenario is expected to provide an upper bound on the value of these transmission connections.

And third, I will combine both transmission expansion scenarios together to see the interplay between the two. This can be insightful since hydropower imports can play the role of fast-burst resources that smooth out the intermittency of wind, even though no storage function is included in the hydro modeling. Furthermore, the peak-shaving benefits from the hydro imports will become available without constraints also to the southern states in New England and not just Vermont and Maine which have a direct interconnection with Canada.

6. RESULTS AND DISUCSSION

The output which EleMod supplies from each scenario consists of large amounts of data. The relevant exercise in the preparation of this chapter was to aggregate the output into readable results and choose meaningful measures, graphs and tables to provide insight for answering the research question addressed with this optimization model.

In section 6.1, I present the results of the benchmark run, which aims to reproduce the 2016 generation mix of the New England power sector to validate the model.

In a second step, I calibrate the model. I use the 2016 results for installed capacities per technology and add them to the existing capacities (based on 2016 EIA data). Once calibrated, I use the model to investigate scenarios with different assumptions about transmission capacities and renewable portfolio standard (CES) policies. All of the scenarios explored are defined in Chapter 5 (see Table 9).

The reference case (*RefTrans* with *CESbase*) is based on the current transmission network capacities and RPS commitments of the New England states. By example of the reference case, in section 6.2 I introduce the types of graphs and tables that I will use to discuss the model results in the following sections. These include total system costs, annual and cumulative installed capacity, the generation mix as well as cost shares of capacity and generation and total emissions levels.

The first series of results which I present below are from the scenarios that demonstrate the impact of increased transmission capacities on the border to Canada (*TransCan*, see Section 6.3). By increasing capacities, hourly import constraints for the model are relieved and the model can shift hydropower imports from Quebec more freely to take advantage of their peak-shaving abilities. Across the three CES scenarios, I evaluate the impact that the transmission expansion at the Canadian border has on the system compared to the *RefTrans* cases.

Similarly, I assess the impact of increased transmission capacities on the transmission interfaces within New England (*TransNEngl*, see section 6.4). By increasing the capacity of the transmission lines in the region, I alleviate any congestion on the network. While not economically feasible to implement in the electric power sector, these scenarios provide an upper bound on the value of transmission capacities. I also report the maximum values of trade on the transmission interfaces to get a sense of how much of the transmission capacities would be used in a “copperplate” approach. An interesting detail of these scenarios is how the effects of increased transmission capacities differ between the three CES scenarios.

To put these two sections into context, I conduct a first-order calculation of the costs and benefits related to the expansion scenarios for transmission within New England and interconnection with Canada (see Section 6.5).

In section 6.6, I report the differences of the build-out of the electric power system under the three different CES scenarios. The *CESbase* scenario represents the current commitments of states. The *CEShigh* scenario assumes that states will continue to push for more renewables through an increasing CES until 2050 after their current commitments run out. The *RPSdecarb* a scenario assumes a deep decarbonization CES that reaches levels of 95% by mid-century. For all three scenarios, I discuss the implications for capacity expansions of different technologies, the operational patterns as well as the impacts in terms of total system cost and emissions levels.

Section 6.7 explores the last set of scenarios, the *TransAll* scenarios, which combine the *TransCan* and *TransNEngl* transmission capacity expansions. Similar to the other scenarios, I evaluate the impact of the CES trajectories as well as the transmission expansions, but in this case compared to the two baselines of the *TransCan* and *TransNEngl* instead of *RefTrans*.

Finally, in Section 6.8 I conduct a first-order analysis to assess the pipeline capacity that is used to meet natural gas demand, mainly by GasCC and GasCCS plants, across all scenarios.

6.1. Benchmark and Calibration

To validate the model, I run the reference case *(RefTrans* with *CESbase*) for the year 2016 with net load data from ISO-NE (ISO-NE 2018a), as well as generator capacities based on EIA data for 2016 (see Chapter 4). Because the model immediately installs wind capacity to efficiently meet the CES requirement which is slightly stronger in EleMod than the RPS requirement because municipalities are exempt from the RPS (see Chapter 4.2.4), I deactivated the installment of new capacities for the benchmark 2016 run. The generation mix from EleMod can be seen in a side-by-side comparison with the historical generation mix data published by ISO-NE (ISO-NE 2018e) in Table 10.

Table 10: Benchmark of EleMod generation mix versus historic New England values

Benchmark	EleMod	New England	% point difference
Coal	0.1%	2.4%	-2.3%
Gas	49.7%	49.8%	-0.1%
Hydro	7.1%	7.1%	0.0%
Nuclear	32.0%	31.0%	1.0%
Bio	6.5%	6.2%	0.4%
Oil	0.0%	0.5%	-0.5%
solar	0.8%	0.6%	0.1%
wind	3.8%	2.4%	1.4%
Sum	*100.0%*	*100.0%*	

Most technologies show only slight differences of around one percentage point. The only outliers are coal and oil. They are utilized very little in EleMod, but they only play a supportive role in New England's electric power sector.

For the calibration, I ran the benchmark for 2016 to see how much new capacity EleMod installs. The model results show an increased capacity need of 3.23 GW of wind, and 278 MW of GasCC. This is consistent with the ISO Interconnection Queue (ISO-NE 2018d). In order to calibrate the model for my analysis, I add these installed capacities to the values of existing capacities from the EIA 2016 dataset (see Chapter 4.2.1) which the model draws upon.

6.2. The Reference Case

The Reference Case *(RefTrans* with *CESbase*) is the closest mapping of the New England power sector with its existing generators, transmission interface capacities, and current CES commitments in EleMod. In the following subsections, I introduce the types of model results that I will use to compare and contrast the outcomes of the transmission and CES scenarios later on.

For each scenario, EleMod provides output data on the annual capacity expansions, hourly output levels for all technologies, hourly flows over all transmission lines, and many more parameters. Through the code in the reporting section of EleMod, I aggregate these values into statistics per year, per resource group, and for the entire New England region. I also export total system costs as a key summary statistic. Beyond these data, the output from EleMod also includes information on various operational details of the technologies and the system operations, for example procured marginal and operating reserves and hourly marginal electricity prices for each region. The graphs and tables below are thus a selection of relevant output parameters to provide for the discussion of the research question.

6.2.1. Total System Cost

As seen in Figure 10 below, the total system cost rises continuously from 2018 to 2050, at rates of around 25% per 4-year interval in the beginning, and 10% towards the end of the modeled time horizon. Three factors can help explain this trajectory. First, the electricity demand, taken from the AEO 2017 forecast for the US, increases by 24% between 2018 and 2050. Second, real prices of fuel (in 2016 $) for natural gas, coal, uranium, and petroleum increase by 20–55%, with gas as the most widely used fuel increasing by 55% (NREL ATB 2017). Third, and most importantly, the CES trajectory for the baseline scenario, which reflects the current commitments made by states, increases until around 2030. This forces more power to be supplied from CES-eligible resources that are more expensive than conventional resources, given that externality effects of greenhouse gas emissions are not monetized. The cost trajectory is reasonable since as the effect of the CES tapers off after 2030, cost increases fall to a steady rate of around 10% per 4-year-interval.

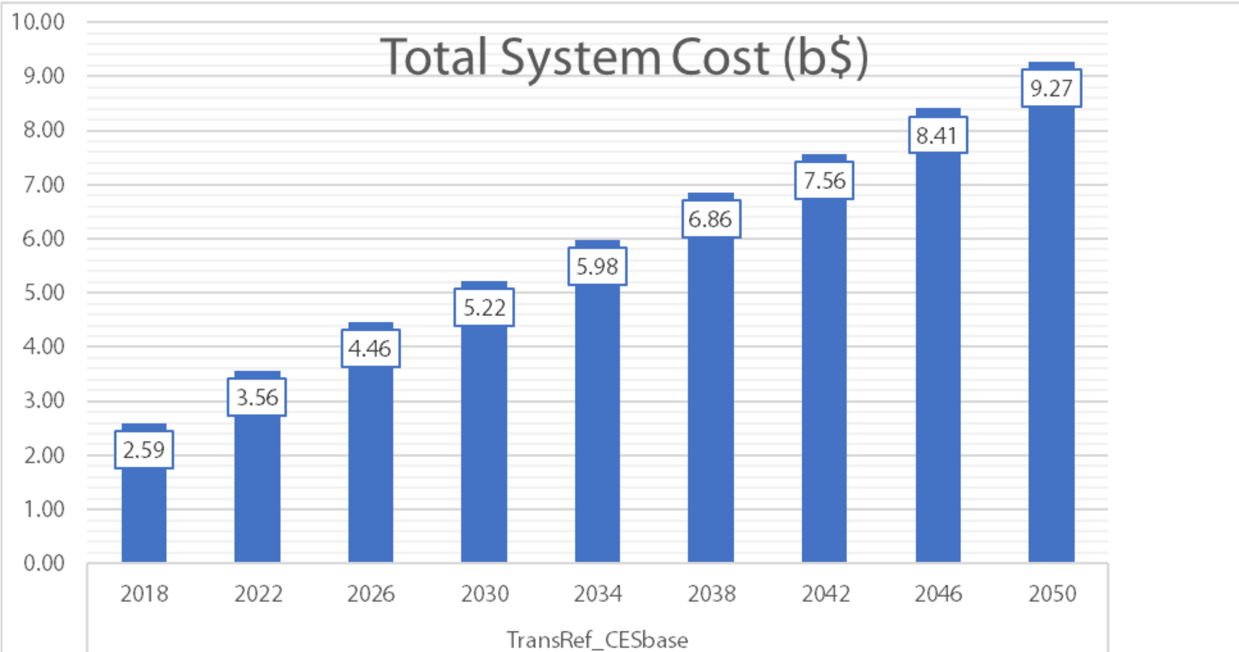

Figure 10: Total system costs (in b$) for TransRef_CESbase from 2018 to 2050

6.2.2. Installed Capacities

The installed capacities show two trends (see Figure 11). First, in the earlier years, overcapacity of conventional generation plants slowly melts away as CES-eligible renewable generation is built. Then, starting in 2022, but in full force in 2026, we see a constant amount of conventional generation capacity added in each time interval to replace retiring capacity and meet marginal reserve requirements. The economics show that natural gas-fired power plants are the cheapest option, with a mix of combustion turbine (GasCT) and combined-cycle plants (GasCC). They have the lowest fixed annualized cost (fca) of all technologies (84.91 and 95.69 $/kW-yr for GasCT and GasCC, respectively), an efficient heat rate (9916 and 6463 Btu/kWh), and relatively low fuel prices for natural gas (see Appendix B). Secondly, we see increased shares of renewable capacity up to and including 2026. This is well explained by the CES requirement, which is rising during this timeframe, but flattens out between the years of 2020 and 2035, depending on the state. 13 Starting in 2030, with the availability of carbon capture use and storage technologies, GasCCS becomes the cheapest

[13] With the exception of Massachusetts which follows an annual increase of 1%.

CES-eligible resource and thus becomes an important contributor to meet the CES requirements. Finally, note that we do not see any newly installed capacities of nuclear power.

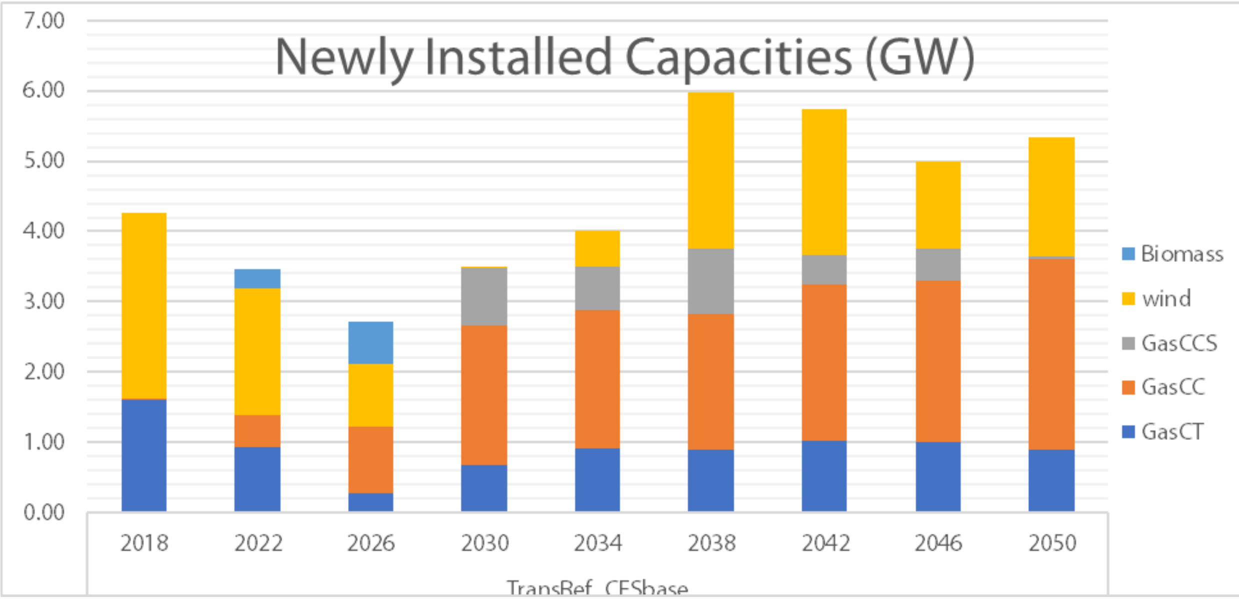

Figure 11: Newly installed capacities per 4-year interval (in GW) for New England

The cumulative capacities (see Figure 12 below) show a steady level of installed capacities on the system over time, which is perhaps surprising given the increase in demand as well as the growing renewable generation. In particular, the addition of wind, which has a lower capacity factor and hence requires more installed capacity per "firm MW"[14], would suggest rising levels of overall installed capacities. What drives the steady level of installed capacities is the fact that the system is currently considered to possess overcapacities, even after accounting for marginal reserve requirements (ISO-NE 2018c). If it were not for the additions of new renewable generation, the total installed capacities of the system would decrease. In the later years, we do see a small but steady increase, which can be expected due to the moderate electricity demand increases based on the AEO 2017 forecast.

[14] A "firm MW", also called "capacity credit", is one MW of power that is statistically available at any given time. This is important for calculating system reserves. Intermittent resources like wind have a capacity credit of 10 to 30%, depending on the technology of the installation and overall installed capacity on the grid.

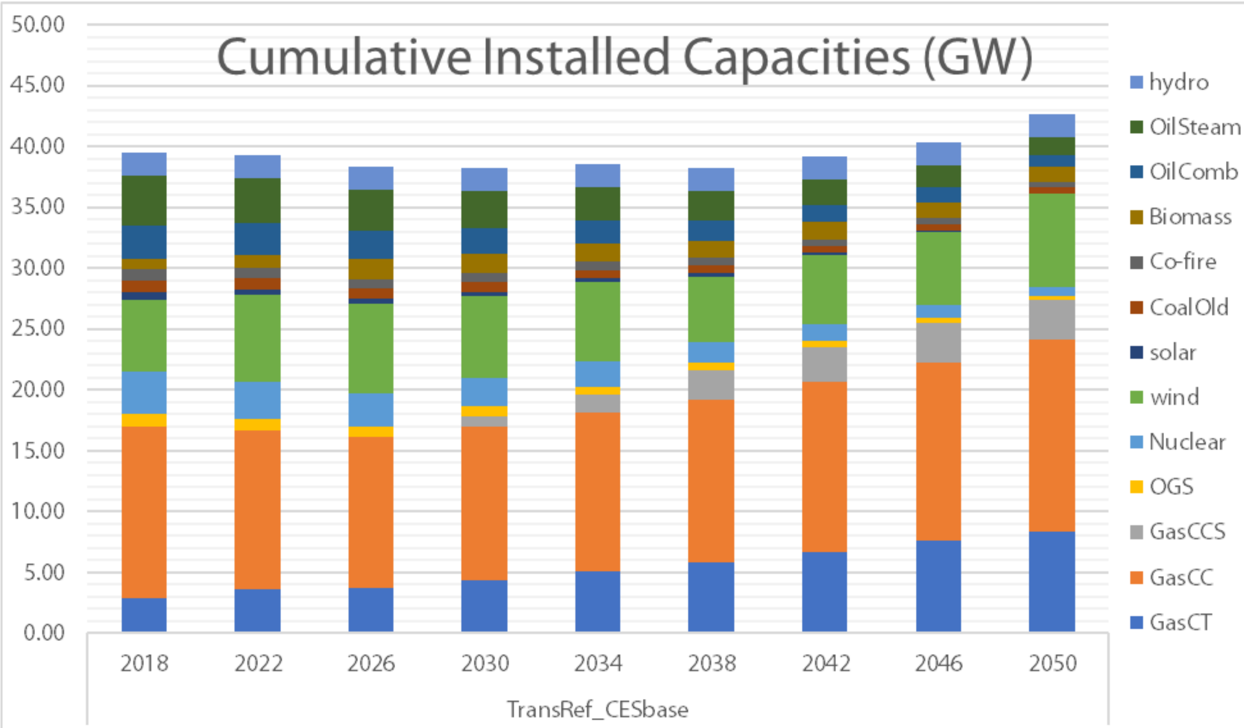

Figure 12: Cumulative installed capacities (in GW)

6.2.3. Generation Mix

The generation mix shows the steady increase in demand for every 4-year interval (see Figure 13). The share of natural gas combined-cycle power plants (GasCC) remains steady, increasing approximately at the same rate as overall demand. GasCCS captures increased market share after it becomes available in 2030. Nuclear power is on the decline as it retires. Furthermore, in this reference scenario wind plays an important role before GasCCS becomes available, but its share of the generation mix decreases again after 2030. However, in contrast to solar, which is pushed almost completely out of the market, wind maintains a market share of about 12% of annual generation in 2050. Lastly, biomass sees moderate increases before 2030, and remains at around 9% until 2050. The system uses peaking technologies such as OGS, GasCT, CoalOld, and petroleum plants in rare situations of scarcity.[15] Also, wind is curtailed at very low levels.[16]

[15] Gas Combustion Turbines (GasCT) have low capacity factors, but the technology is installed at moderate levels throughout all the years (see Figure 11). This is because they play an important role to meet the marginal reserve requirements for the system and provide back-up capacity in scarcity situations.

[16] Wind curtailments are calculated as negative generation values. The x-axis is cut off at 0 in this figure, but at this resolution of the graph "WindCur" was not visible in other axis configurations either.

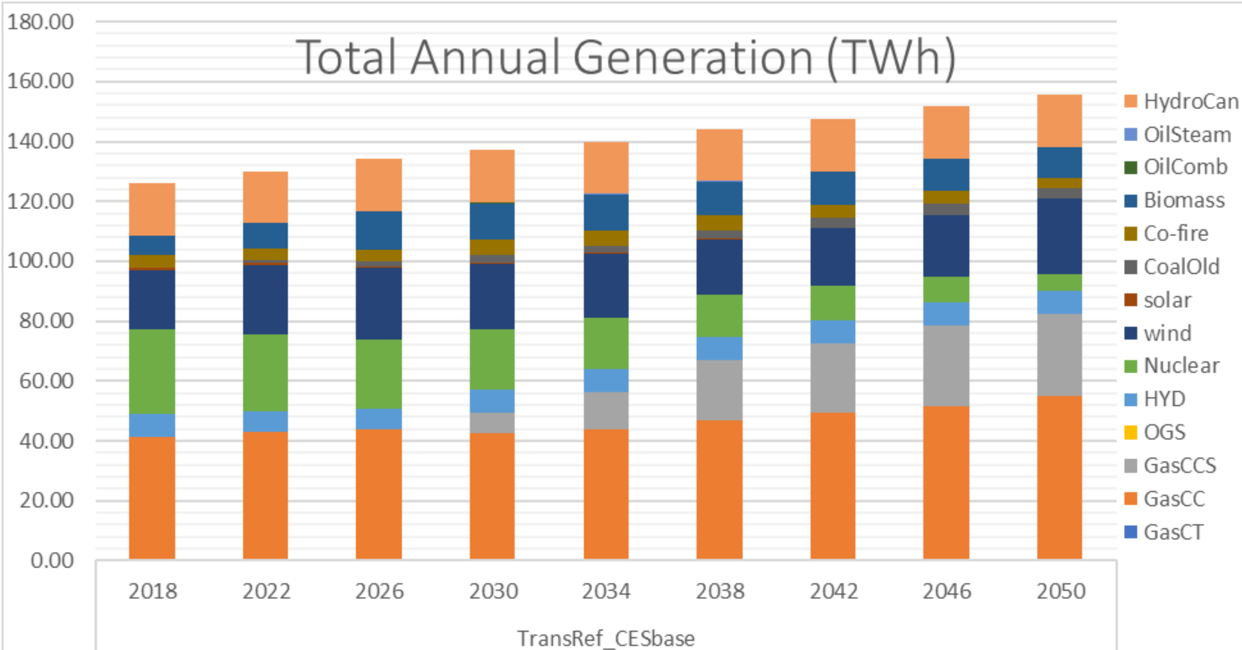

Figure 13: Total annual generation (in TWh)

6.3. Increased Interconnection with Canada

To explore the impact of increased transmission for hydro imports from Canada, the line capacities between New England states and Canada are increased to a very large value to be essentially unlimited. This allows the system to use available hydropower from Canada to reduce system costs in an optimal way without being subject to hourly transmission constraints. The amount of energy available per year remains the same, but the allocation can be more concentrated during the hours where it is most valuable, i.e. the hours of highest net demand.

Increasing transmission capacities with Canada to make better use of the available hydro power has an increasing effect as the system evolves, reducing total system costs between 3 and 6.6%, and on average 4.29% per year. This suggests that the system adapts interval-by-interval to the fact that it has increased transmission capacity at its disposal, replacing retired power plants with configurations that take advantage of transmission. The percentage cost decrease is also stronger in the scenarios with higher CES requirements.

The decrease in cost reduction in the *CESdecarb* scenario in 2046 and 2050 is owed to the fact that under current CES rules, hydropower imports from Canada are not eligible to meet the CES requirements. In these two years, the optimization model thus foregoes the "zero cost" hydropower imports from Canada and meets demand with additional generation from GasCCS plants. However, this counter-intuitive behavior of the model would most likely never come to happen. Lawmakers originally designed the CES measure as an incentive program to create more renewable generation capacity in the region. In a world of decarbonization level CES requirements, however, low-carbon hydropower imports will have to be worked into any sensible standards.

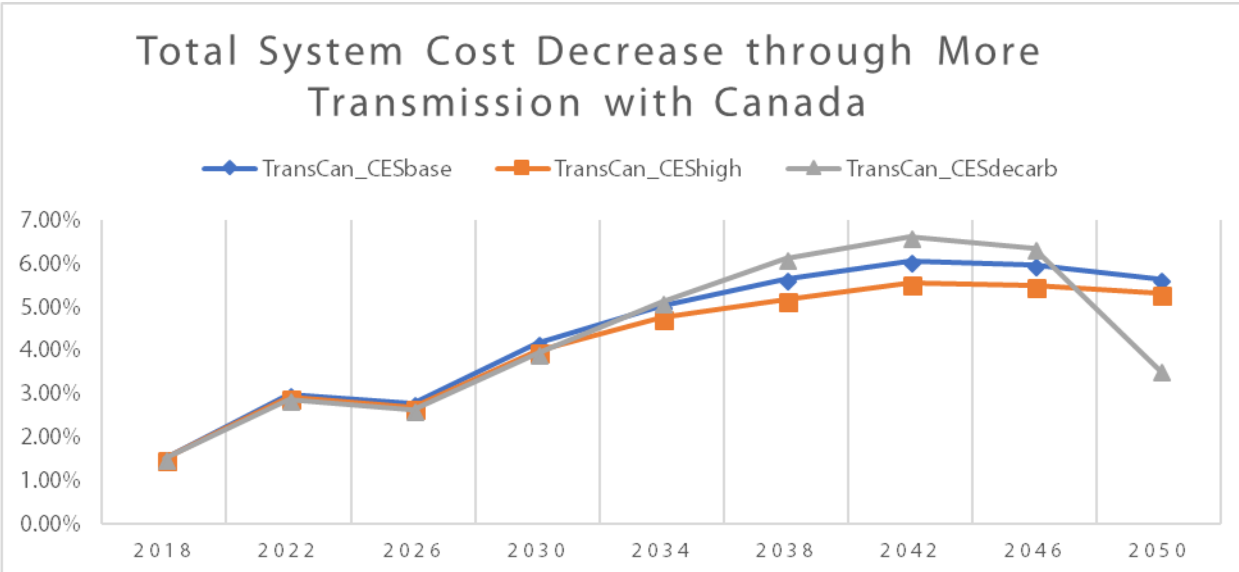

Figure 14: Total system cost decrease through more transmission capacity with Canada

As explained in chapter 4.2.2, the costs for hydropower from Canada are not incorporated into the objective function. However, EleMod reports hourly locational marginal prices for electricity in each state, and assuming hydropower from Canada is purchased at the hourly prices, the costs of imports can be tracked. Without the hourly transmission constraints in scenario *TransCan*, we have larger amounts of hydropower imported in the highest-price hours. This leads to an increase in the cost of hydropower imports, which should be offset when considering the cost decreases of allowing for larger interconnection capacity with Canada. The magnitudes are not negligible (they are on the order of $72 million of higher import costs), but they only decrease the system cost savings by about one percentage point, moving the average cost decrease closer to 3%.[17]

It is noteworthy that the generation mix shows close to no change between the *TransRef* and *TransCan* scenarios (see Figure 15, depicting the *RPSdecarb* scenario as an example). GasCCS

[17] Example for 2034: The increased cost of hydropower imports of 0.072 billion-$ (0.774 billion-$ for imports in *TransRef_CESbase*, and 0.846 billion-$ for *TransCan_CESbase*) stands against a decrease of total system costs of 0.503 billion-$. Adding the increased prices for hydro, the cost decrease through transmission amounts to 4.04%.

decreases slightly, while wind power is the only resource that is affected to a significant degree. With increased interconnection capacity at the Canadian border (*TransCan*) wind retains more of its market share established in the 2020s, settling at 12.9% in 2050, compared to 7.9% in the *TransRef* scenario under *CESdecarb*.

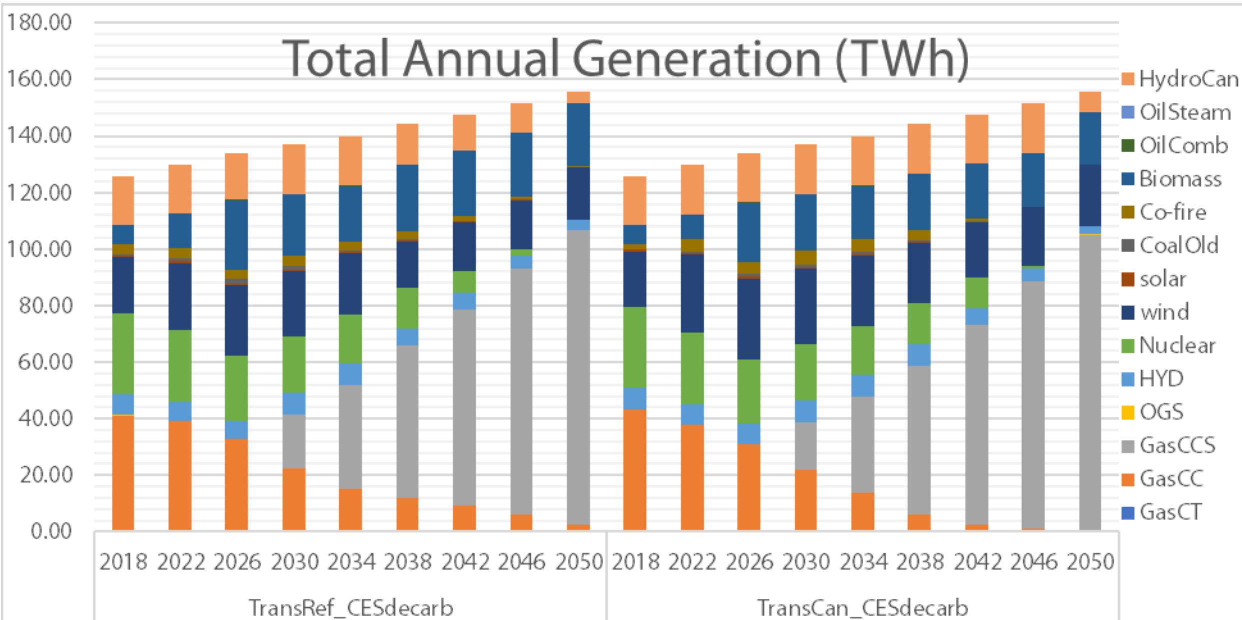

Figure 15: Comparison of the generation mix (in TWh) between TransRef and TransCan scenarios, adding increased transmission capacities on the Canadian border (both with CESdecarb)

Furthermore, increasing hydro import capabilities affects the capacity expansion of the system only marginally (see Figure 16 below). More wind is installed in 2022, and again in 2042 after the 20-year lifetime runs out and the resources retire. In return, we see lower additions of GasCT and GasCC in the *TransCan* scenario over the next years. But overall, the picture remains similar.

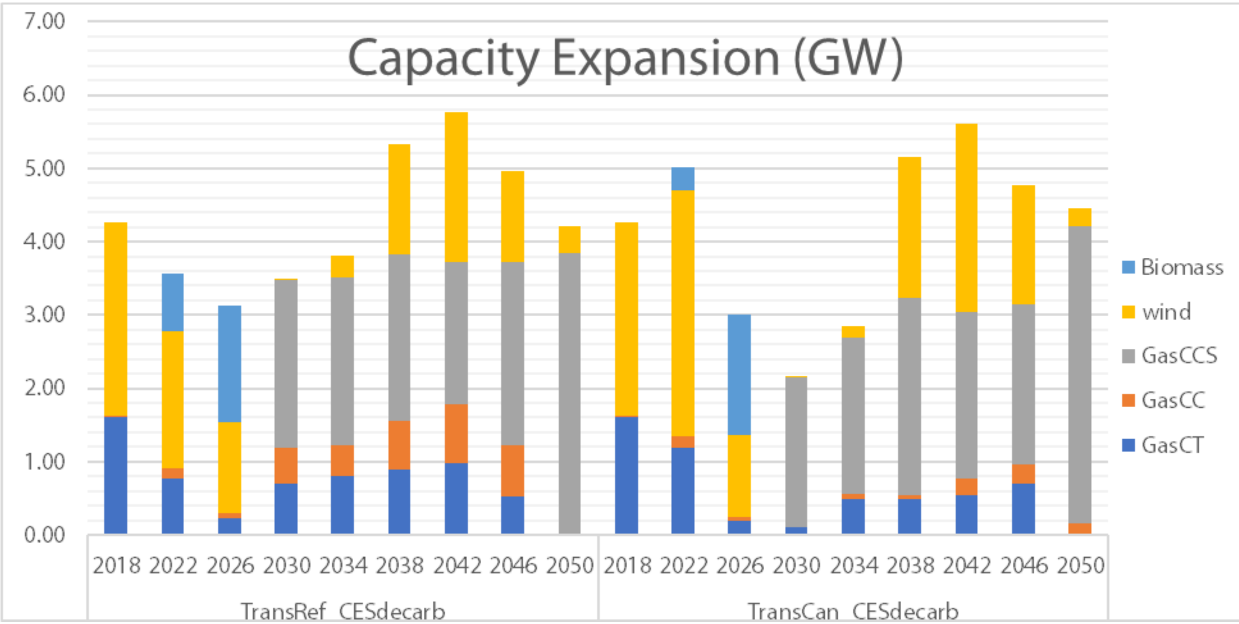

Figure 16: Comparison of capacity expansion between TransRef and TransCan scenarios, adding increased transmission capacities on the Canadian border (both with CESdecarb)

This begs the question how increasing transmission capacities with Canada can lower system costs substantially, while capacity expansion costs remain largely the same. We can observe the answer in the lower average marginal locational prices in the *TransCan* scenario, where the bordering states to Canada receive substantially lower marginal locational prices (see Table 11).

Table 11: Comparison of average locational marginal prices (LMP) for all states between TransRef and TransCan scenarios (both CESbase)

LMP (in $/MWh)	CT	MA	ME	NH	RI	VT
TransRef	56.36	56.68	42.99	48.93	56.73	45.82
TransCan	56.69	57.03	30.83	32.74	57.06	32.74

6.4. Increased Transmission between New England States

Next, I explore the impact of transmission between New England states. To do so, I increase capacities on the transmission interface within New England to be unlimited in order to provide an upper bound on the value of an increased transmission network. Figure 17 shows the annual cost decreases that transmission expansion can achieve, which are 3.95% on average. The pattern is similar in all three CES scenarios, while the cost decreases are slightly stronger in the scenarios with higher CES targets.

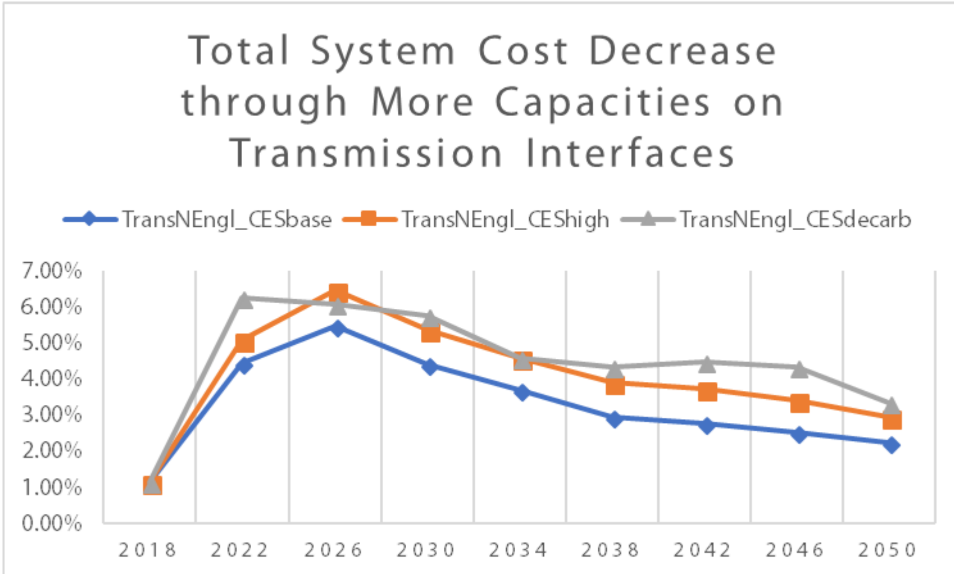

Figure 17: Total system cost decrease through increased capacities on transmission interfaces

Unlike with the expansion of interconnection capacity with Canada, the cost savings from increased transmission capacity within New England decrease as the system evolves. This suggests that the system reaches a point of saturation quickly where it can take advantage of all increased transmission capacities.

By closely examining the newly installed capacities (see Figure 18), we see that increased transmission capacities unlock wind generation, mainly in Maine. In 2022 and 2026 of the *CESbase* scenario, the *TransRef* scenario chooses to expand biomass whereas the *TransNEngl* scenario instead expands wind. In 2050, wind is similarly able to take some of the capacity from GasCCS in the *TransNEngl* scenario.

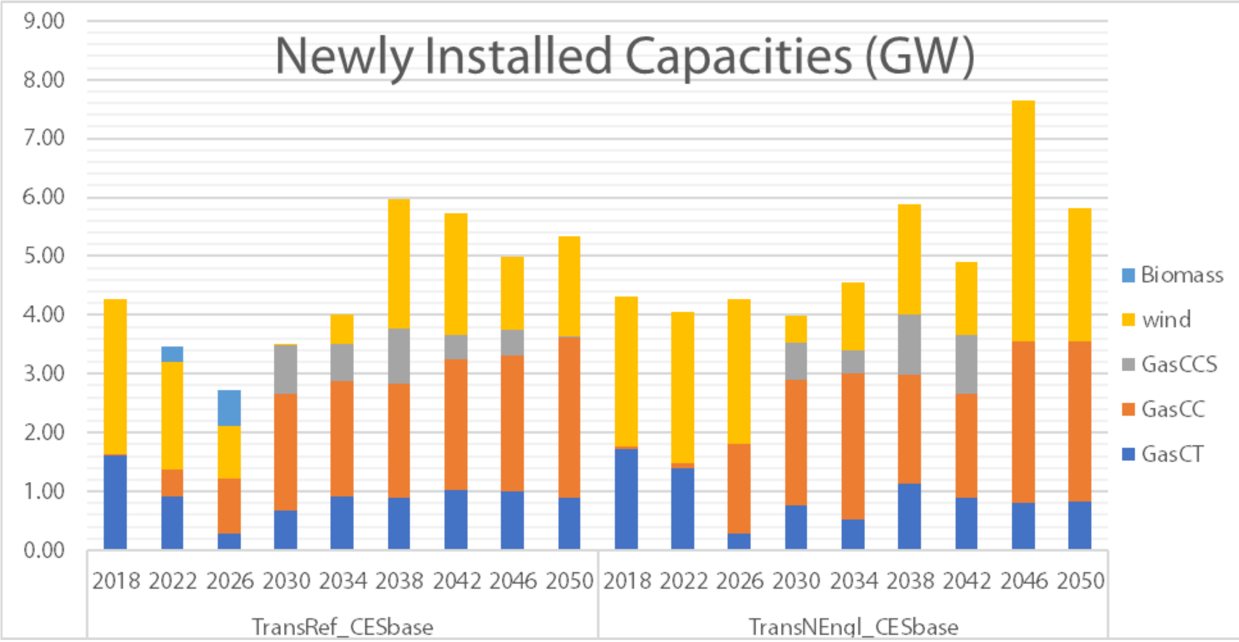

Figure 18: Comparison of newly installed capacities (in GW) between TransRef and TransNEngl (both with CESbase)

We can also see this story by comparing the shares that wind holds in the generation mix between *RefTrans* and *TransNEngl* scenarios (see Figure 19).

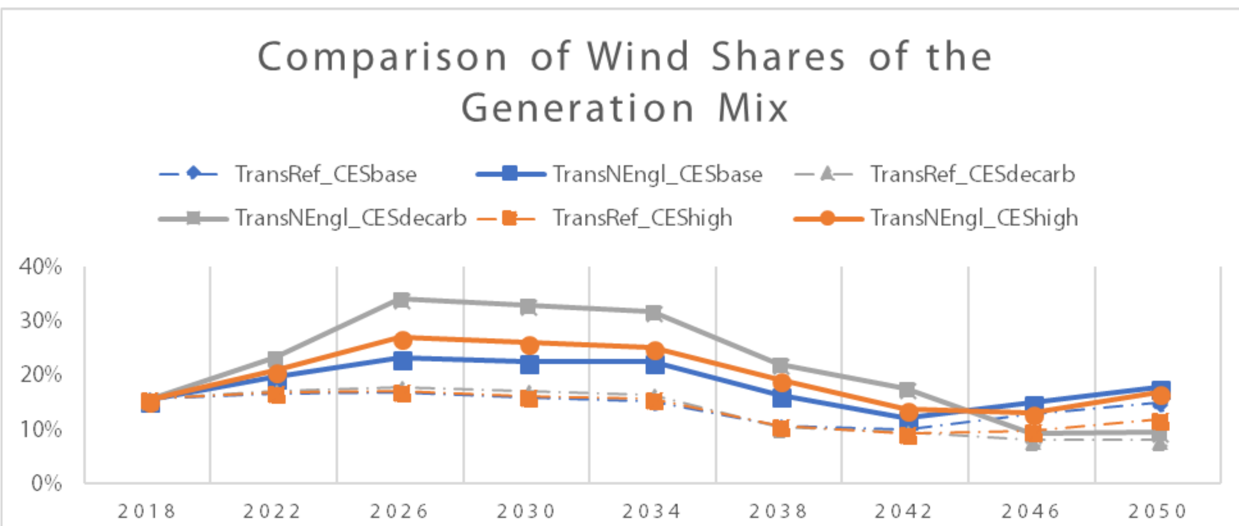

Figure 19: Comparison of wind percentage points of the generation mix between TransRef and TransNEngl scenarios.

In all three CES scenarios, unlimited transmission capacities lead to a share of wind in the generation mix that is 6 to 16 percentage points higher than under reference transmission capacities. The behavior over time of the three *TransNEngl* scenarios is noticeable though: Increased transmission capacities provide a boost to wind as the system evolves, but by the end of the horizon of the analysis this advantage is again reduced. Furthermore, the effect of the boost to wind power is significantly higher in the scenarios with higher CES requirements, driven by the CES' push for more renewable integration. To analyze in more detail, in the early years, the increase of wind shares unfolds. In the middle years, even as GasCCS becomes available and even though total wind shares drop in all scenarios, the difference of wind shares in the generation mix between the *RefTrans* and *TransNEngl* scenarios remains constant. Only after 2034 do we see the boost for wind provided by increased transmission capacity expansion wither away. Nonetheless, the wind shares of the *TransNEngl* scenarios level off slightly above their counterfactuals in the *TransRef* scenarios. Interestingly, the *CESdecarb* scenario ends up with the lowest wind share increase in 2050.

6.5. Transmission Capacity and Costs

In the previous two sections, I have examined the cost reductions of increasing transmission capacity in New England and interconnection capacity with Canada, as well as the effect of these measures on the evolution of the electric power sector. The presented cost savings estimates are significant, but they only represent the upper bound of the value of increasing transmission and interconnection capacity in New England. To put these numbers into perspective, in this section I conduct a first-order cost-benefit calculation for the costs of expanding the transmission and interconnection capacities to the levels utilized in the modeling runs.

For this purpose, I first extract the values of flows on the respective lines to evaluate how much of the unlimited transmission capacity was in fact used. From the distribution of utilization levels, I extract the amounts of transmission capacity which would allow the flows to be allocated in at least 90% of the hours. I then determine how much new transmission capacity would be required. Then, based on cost estimates from an ISO New England transmission system study, I calculate how much that additional transmission capacity would cost for the system, and compare it to the system cost savings from sections 6.3 and 6.4.

First, I analyze the interconnection with Canada, and thus the line flows of the *TransCan* scenarios.[18] For the *CEShigh* scenario, the *New England II* interconnection from Vermont to Quebec would be utilized at levels of up to 7.5 GW per hour, and Maine's interconnection to the New Brunswick is utilized up to 3 GW (see Figure 20). The current capacities of the Vermont and Maine interconnections are 1,600 MW and 700 MW, respectively. This scenario thus requires new capacity of 4,000 MW and 2,500 GW, respectively.

[18] Note that in the *TransRef* scenarios, line flows during all hours are below the maximum line capacities of 1.6 GW and 0.7 GW for Vermont and Maine, respectively.

In the New England 2030 Power System Study (ISO-NE 2010), ISO New England estimates transmission expansion costs for interconnection with Quebec at $1.6 billion per 1,500 MW, and interconnection with New Brunswick at $2.0 billion per 1,500 MW.[19] Therefore, to achieving the transmission levels in the *CEShigh* scenario would require the construction of roughly three of the interconnectors from Vermont to Quebec at $4.8 billion, and two interconnectors from Maine to New Brunswick at $4 billion, totaling $8.8 billion.

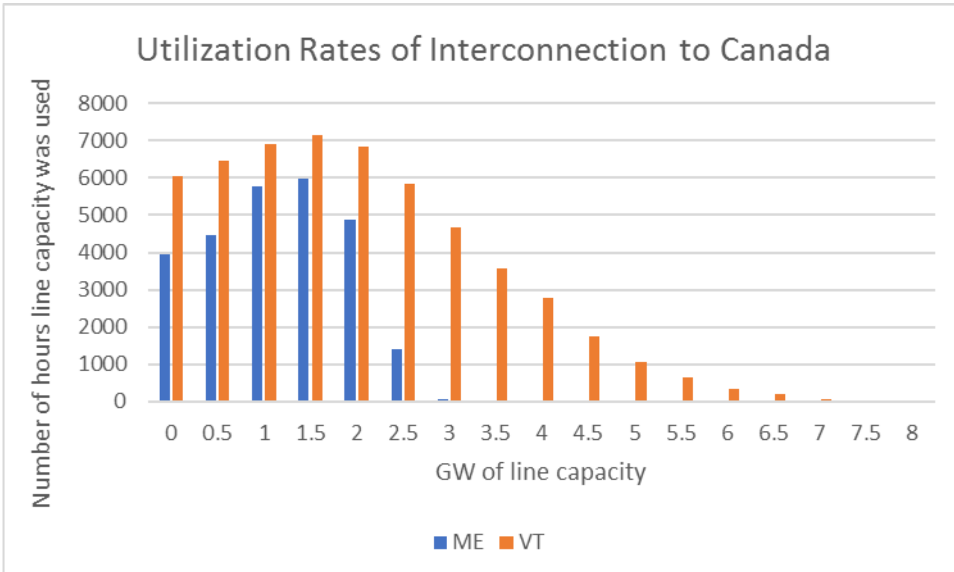

Figure 20: Utilization rates of interconnection from Vermont and Maine to Canada

These values must be compared to the cost savings which the increased interconnection capacity provides. Based on the results in section 6.3, total cost savings in the *CEShigh* scenario are $46 million in 2018, but $535 million in 2050 (all 2016 $). Transmission lines have a long lifetime. In fact, they are rarely ever decommissioned. I thus calculate cumulative cost savings over the time horizon of the analysis, which is 32 years (2018-2050). This is a reasonable financial lifetime to apply for a transmission line. We must then account for the years in between the 4-year intervals of the analysis. Assuming that cost savings in the three years following each modeled year remain the same, the benefits accrue to $8.724 billion. This cost savings is extremely close to the $8.8 billion estimation of the cost of the additional transmission. This suggests that investment in additional transmission interconnections with Canada at levels close to those required in the *TransCan_CEShigh* scenario could be worthwhile. A more detailed look at expanding interconnection capacities with Canada,

[19] ISO New England specifies the costs as "Preliminary Order of Magnitude Cost Estimate Ranges". While these values are not sufficiently reliable for assessing the value of transmission capacity, they suffice for the first-order cost-benefit calculation which supplements my analysis.

possibly to the degree that accommodates optimal cross-border flows in 90% or more of the hours, is strongly recommended.

For the increase in transmission capacities on the interfaces within New England, I proceed likewise. In this discussion, I focus on the *CEShigh* scenario, because it represents the most realistic path for future commitments to mandate low-carbon generation sources. Again, I undertake a first-order calculation of costs and benefits. To recall, I model three interfaces: Connecticut-Massachusetts (2,500 MW), Massachusetts-New Hampshire (3,400 MW), and New Hampshire-Maine (1,475 MW).

In the *TransNEngl_CEShigh* scenario, the Connecticut Import transmission interface (between Connecticut and Massachusetts), currently at 2.5 GW, is utilized above that capacity in less than 1% of the hours. Thus, the conclusion is that there would be no need to increase transfer capacity of this transmission interface. The Maine-New Hampshire interface, which is currently at 1.475 GW, is utilized in this scenario at levels up to 3.8 GW, with 90% of the hours below 3 GW. And the North-South interface (Massachusetts-New Hampshire), currently at 3.4 GW, is used up to 7.8 GW, with 90% of hours below 5.8 GW. Thus, the resulting transmission increases should be around 2 GW each for Maine-New Hampshire and Massachusetts-New Hampshire interfaces[20].

For cost estimates of increasing transmission capacity on the New England interfaces, I use as reference the interconnection of 2,000 MW of on-shore wind addition in Maine from the 2030 Power System Study (ISO-NE 2010). The cost estimate is $5.9 billion for a line circuit carrying 2,000 MW of new wind capacity from Northern Maine to the load centers. Considering that EleMod does not allow direct transmission from Maine to the load centers in Massachusetts, the fact that both Maine-New Hampshire and New Hampshire-Massachusetts lines require an increase of around 2,000 MW of capacity is closely in line with the scenario studied by ISO New England. Thus, I assume that the $5.9 billion expansion, which includes lines from Northern Maine through lower New-Hampshire and into Massachusetts, serves the dual-purpose of increasing both transmission interfaces.

The benefits of increased transmission found in Section 6.4 are $34 million in 2018, around $200 million in 2022 and around $300 million every year after that. In total, following the same assumptions about calculating the cumulative cost savings as above, these accrue to $8.324 billion. While this is certainly larger than the cost estimate of $5.9 billion, this calculation is a bit more lenient

[20] A 2 GW increase to 5.4 GW accommodates optimal flows in 85% of the hours on the Massachusetts-New Hampshire interface.

as an expansion of 2,000 MW will only allow optimal flows in 85% of the hours for the Massachusetts-New Hampshire interface, and the project for which ISO New England created the cost estimate does not exactly match the expansion suggested by the results from my analysis with EleMod. Nevertheless, this comparison suggests that investments to increase transmission capacity within New England to levels similar to those from the *TransNEngl_CEShigh* are likely wise investments worth further exploration.

6.6. CES and Decarbonization

One important feature of my analysis is the scenarios with increased CES trajectories, *CEShigh* for continued commitments to increasing the CES until 2050, and *CESdecarb* which gradually elevates the CES to levels of 95% that would correspond to a deep decarbonization scenario.

As is forced by the CES requirement, the shares of capacity expansion from renewables and low-carbon resources eligible for the CES are higher with increased CES targets. The results strongly suggest that GasCCS is the cheapest resource for the system to meet the CES requirements. Among all CES-eligible resources, however, GasCCS does not have the lowest fixed annual cost: it's 210.92 $/kW-yr are higher than wind (187.19 $/kW-yr) and solar (179.84 $/kW-yr), and GasCCS also has a variable O&M cost of 6.90 $/MWh, whereas the two renewable resources have zero variable cost. The results show clearly though that GasCCS largely beats out wind, and solar capacity is never installed by the model. This is due to the availability factors of the two renewable sources. Because of their intermittency, they are only 40.1% (wind) and 15.1% (solar) of the time available to produce electricity. Thus, in sum the dispatchable CES-eligible resource GasCCS dominates the capacity expansion, as well as the generation mix. As would be expected, the share of GasCCS of the generation mix increases with higher decarbonization levels (see Figure 21). As we have already examined and partly explained above, wind shares slightly decrease in the long-term with increasing decarbonization levels.

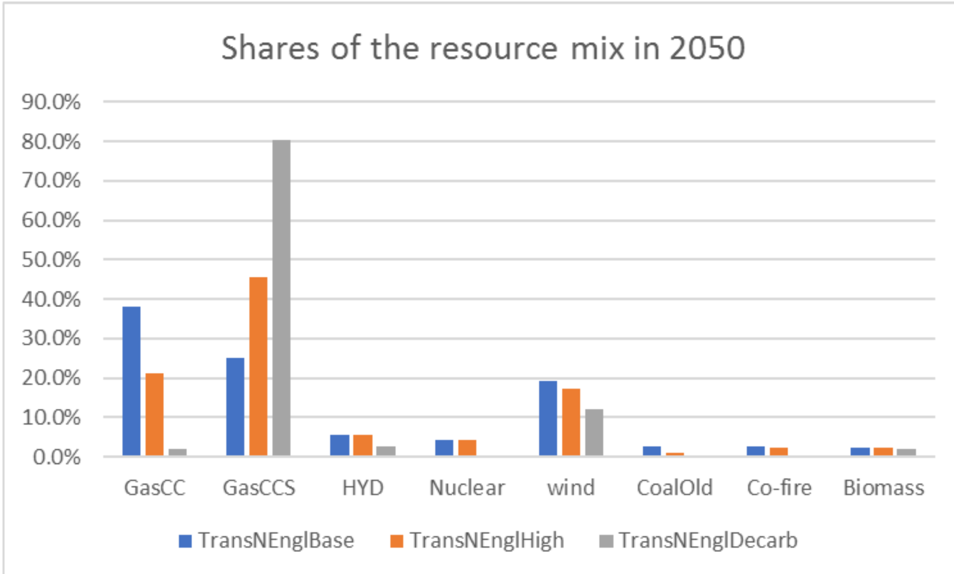

Figure 21: Shares of the resource mix in 2050

A word of caution needs to be said regarding the results of the *CESdecarb* scenario: the scenario has a drastic effect in terms of shift in generation shares, which is of course not unlikely for a deep decarbonization scenario. Most resources are pushed out by GasCCS, while there remains a share of 12% of generation supplied by wind power. The fact, however, that even very low-cost hydropower is pushed out of the generation mix is due to the fact that these resources are not considered CES-eligible under current rules. These rules can be expected to change as the system moves towards decarbonization. Moreover, GasCC is pushed out of the generation mix almost completely, and a moderate level of wind resources remains on the system. The bulk of generation is carried by the resource most economical to meet CES requirements with firm capacity, which based on my assumptions of NREL ATB 2017 cost parameters, is GasCCS.

6.7. Increasing All Transmission Capacities

Finally, I examine the results of the case in which transmission capacities inside New England as well as on the border with Canada are increased. I compare this *TransAll* scenario not to the *TransRef* baseline, but rather to *TransNEngl* to see the effect of combining it with the additional interconnection capacity in *TransCan*. With CESbase under the TransAll scenario, we see a significantly increased amount of wind come onto the grid in 2038 and 2042, where GasCCS plays a smaller role instead (see Figure 22). This makes sense, since the better allocation of hydropower imports across the year allows the system to push out expensive peaking technologies. However, this effect is scaled back until by 2050 there is almost no change in the generation mix between the two scenarios. The *CEShigh* scenario behaves similarly, with more wind and less GasCCS around 2038.

However, in the *CESdecarb* scenario, the combination of increasing both sets of transmission lines maintains its effectiveness until 2050 (see Figure23). Wind shares in the *CESdecarb* scenario under *TransAll* transmission capacities rise to 18.8% in 2050, compared to 12% in *TransRef*, 12.1% in *TransNEngl*, and 13.9% in *TransCan*. Thus, we can observe that under a strong decarbonization policy, more transmission capacities provide a sustained boost to wind resources.

Finally, in the last decade from 2040 to 2050, we see zero hours of petroleum generation from oil combustion turbines, and for the *CESdecarb* scenario also zero hours of oil steam turbines. In *TransRef*, *TransNEngl*, and *TransCan* scenarios these resources still maintained a sliver of operating hours during high net demand periods. While not entirely pushed to zero, the generation share of GasCT (combustion turbine) is also reduced to almost zero.

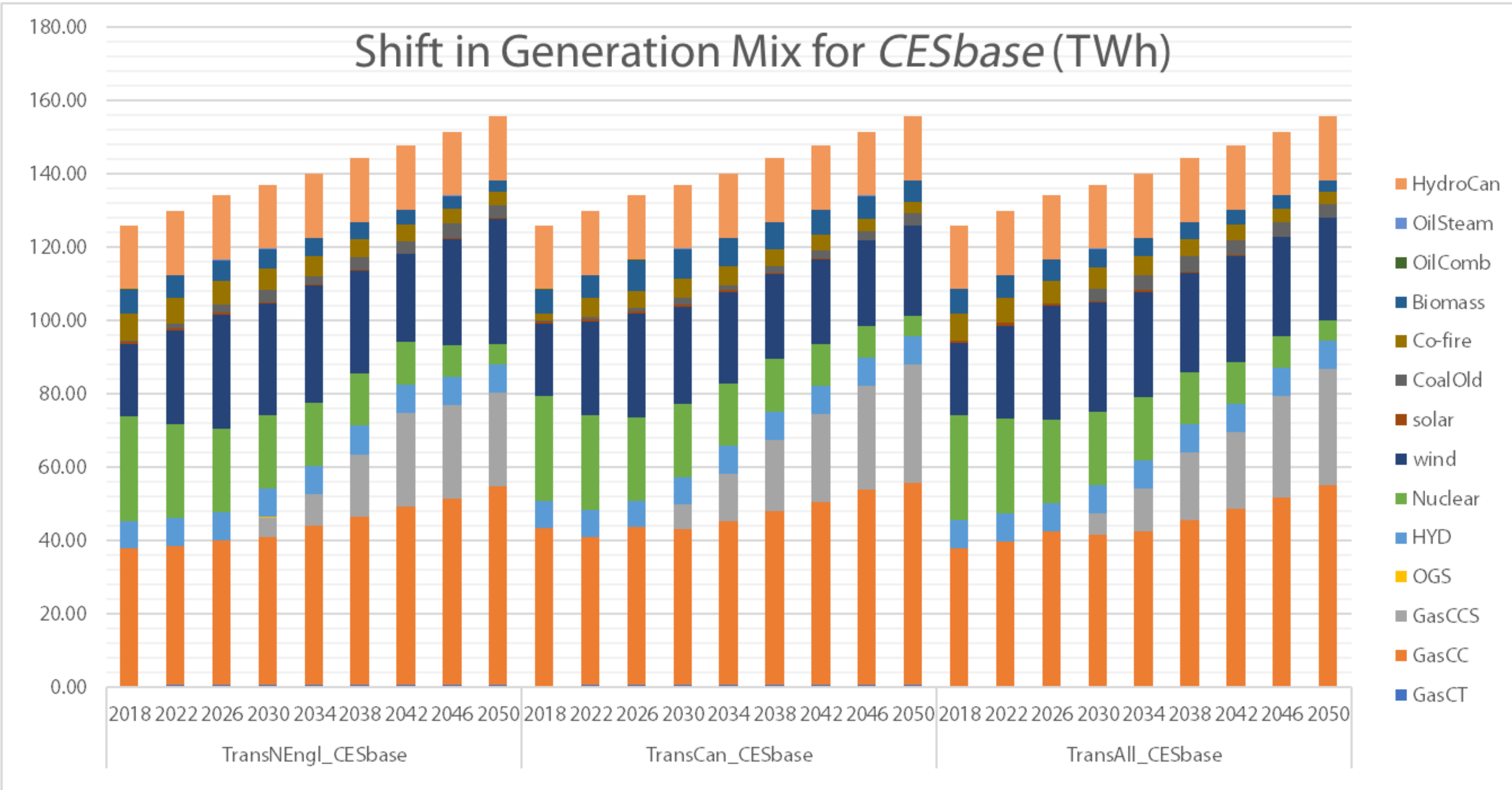

Figure 22: Shift of the generation mix (in TWh) in TransAll compared to TransNEngl and TransCan scenarios (all CESbase)

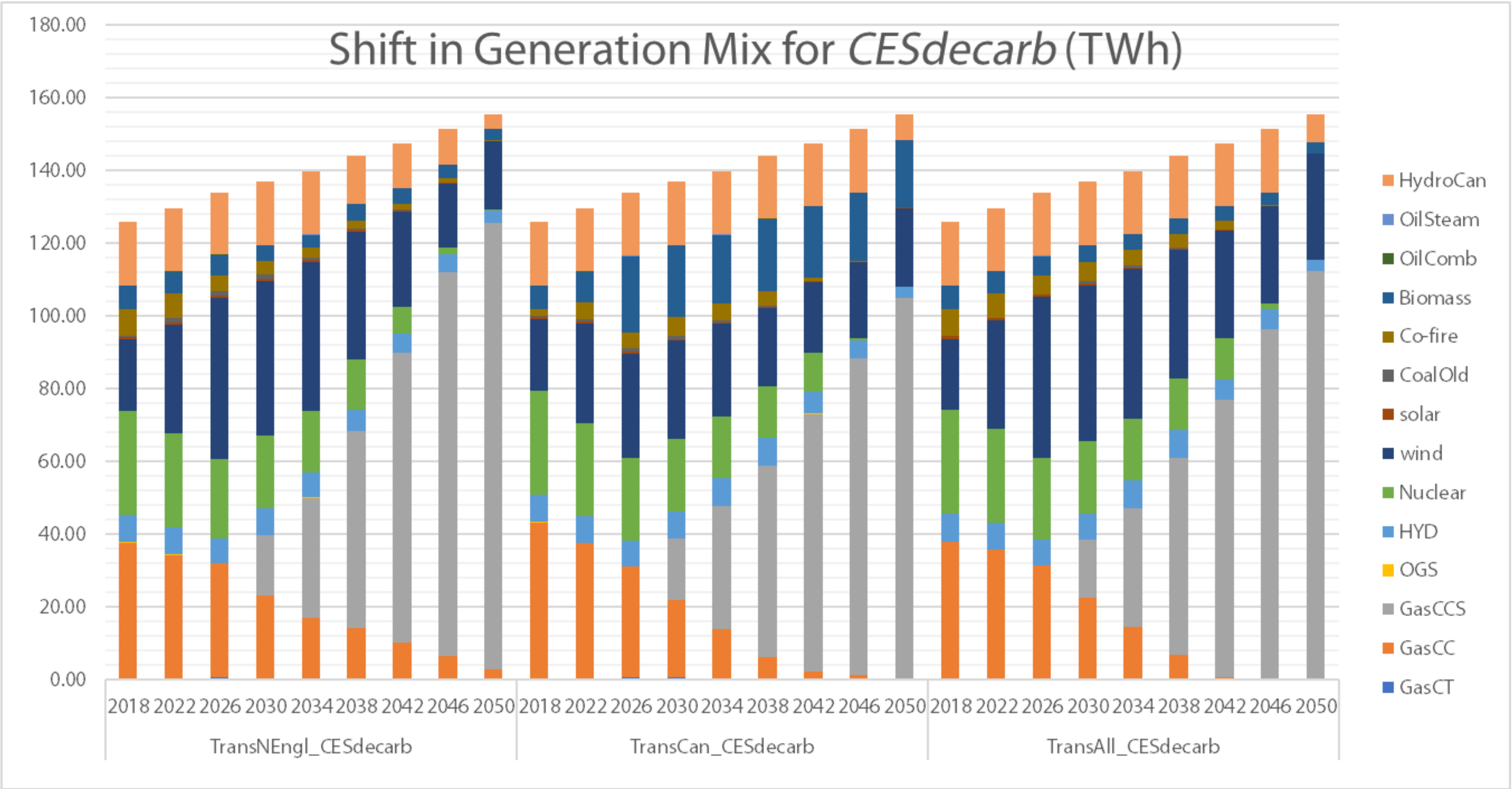

Figure 23: Shift of the generation mix (in TWh) in TransAll compared to TransNEngl and TransCan scenarios (all CESdecarb)

6.8. Gas Pipeline Constraints

To conclude the discussion of results, in this section I conduct a first-order for the demand and supply of natural gas based on the current pipeline capacities into New England. As presented in Chapter 0, the capacity of all current natural gas pipelines and LNG terminals into the region amounts to 5.9 billion cubic feet per day.

In 2050, the examined generation mix of the various scenarios almost exclusively shows an increase in gas-fired electricity generation, with many of the scenarios with high CES targets using GasCCS. This is a reason to think about the implications for the operation of the electric power sector. During the winter months of December to February, daily demand for natural gas from the electricity sector lies between 2 and 3 Bcf. While this does not exceed the pipeline capacity, in these situations most of the available capacity is occupied by utilities serving their customers (see Figure 24).

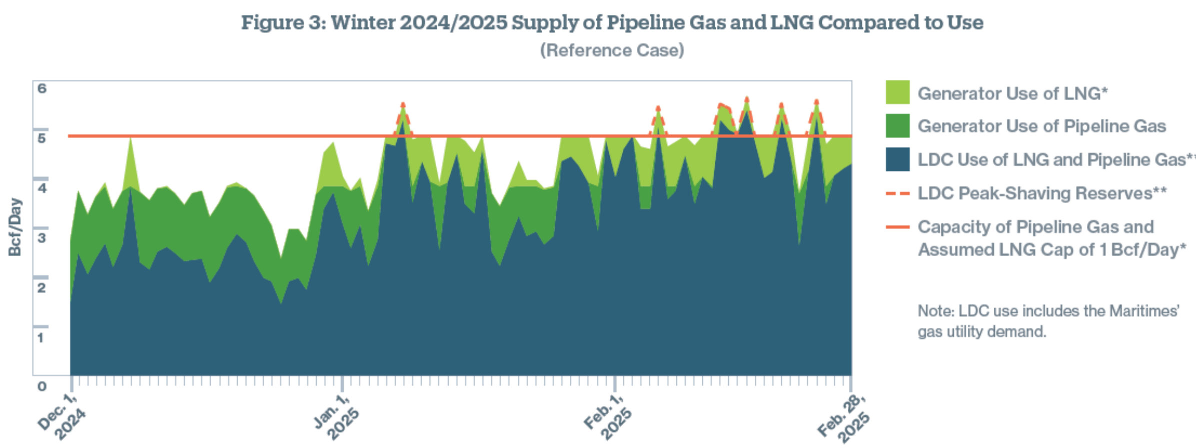

Figure 24: Pipeline capacity and demand from utilities (LDC) and power plants for winter months (ISO-NE 2018f)

However, as laid out in Chapter 0, the relevant issue is whether the power system has sufficient reserve capacity to not depend on natural gas on these days. This becomes an issue that goes beyond the direct aim of this study, but it is relevant to consider the consequences. The Clean Energy Standard as a policy does not intend to choose the perfect resilient mix to prevent winter outages for the electricity sector. The policy hence needs to be embedded in a more comprehensive framework, where fuel availability during critical time periods is one factor. However, it is important to remember to refrain from picking a presumed winning technology or prevent a presumed loosing technology from competing. In long-term systems planning, many issues are in flux: changing fuel prices, declining technology costs, and even change in behavior that leads to different demand patterns.

7. RECOMMENDATIONS AND CONCLUSION

In this thesis, I have explored how increased transmission capacity within New England and increased interconnection capacity to Canada impacts the evolution and cost of the electric power sector in New England under policy scenarios of varying CES target trajectories through 2050.

I built my analysis on the capacity expansion planning model EleMod, which was developed by the MIT Energy Initiative. In addition to creating a detailed representation of the electric power sector in New England in EleMod, my contributions to the model are three-fold: (1) I added an external hydro reservoir resource to adequately represent Canada, which supplies around 16% of load in New England; (2) I implemented a representation of long-distance transmission lines to allow for trade across transmission interfaces between the New England states; and (3) I incorporated a Clean Energy Standard that enforces a share of generation to be met by resources from a portfolio of CES-eligible technologies every year.

Both increasing transmission capacities within New England and increasing interconnection to Canada to allow for a better allocation of hydro imports, provide cost decreases of up to 6.5% annually, or cumulatively over the period of 2018-2050 3.95% for transmission within New England and 4.29% for interconnection with Canada. Transmission expansions from Maine to Massachusetts of 2,000 MW and interconnection expansions to Canada of 3,000 MW and 4,500 MW from Maine and Vermont, respectively, allow for optimal allocation of flows across lines in over 90% of the hours. For interconnection, the calculation estimates costs to be about 1% higher than the benefits, and for transmission within the region the benefits exceed the costs by about 40%. The cost-benefit calculation needs further investigation to make a recommendation for or against building additional transmission capacity. However, it is noteworthy that the benefits of transmission expansion up to levels that accommodate optimal flows in 90% or even more of the hours is within reach of profitability. This would imply a quadrupling of interconnection capacity with Canada, and roughly a doubling of transmission interface capacities between Maine, New Hampshire and Massachusetts. This analysis suggests that investments to expand transmission capacity within the region are potentially more profitable than those between New England and Canada.

It is not surprising that the evolution of the electric power sector in New England depends strongly on the levels of CES targets. The most important result is that with the *CESdecarb* scenarios, GasCCS becomes the dominant resource in the power sector. Due to its ability to both satisfy the CES requirement and operate as a dispatchable resource, and given the cost assumptions in the model, it is the technology-of-choice to be installed to replace retiring capacity and meet increasing demand. With GasCCS as the dominant resource, the share of gas in the generation mix can go up to 85%. Under these conditions and based on the sample yearly load profile used in my analysis, current pipeline capacities will suffice to provide enough natural gas to gas-fired power plants on all days during the year up to 2050. When considering other demand for natural gas, like utilities who serve their customers for home heating with priority access to the pipeline, modest capacity expansions of the pipeline network might be necessary through 2050. On the other hand, some of these use-cases like home heating might decrease simultaneously as the electrification of the economy moves in cadence with the decarbonization of the electric power sector.

Furthermore, the evolution of the generation mix in New England also depends on the choice of transmission expansion that is implemented. Increasing interconnection to Canada for hydropower import gives a slight boost to wind resources but increasing transmission at New England interfaces can enable much more wind—especially in the *CESdecarb* scenarios up to 4.5 GW in some of the 4-year-intervals. Increasing both transmission and interconnection capacities together enables only slightly more wind—up to 4.6 GW in some intervals of the *CESdecarb* scenarios.

In my analysis I have considered the evolution of the electric power sector in New England based on the choice of a set of generation technologies which are relevant in New England, with cost and performance parameters from the public domain. It is important to note that much of the analysis, especially the trade-off between installing the individual technologies, is subject to these assumptions. These assumptions, however, are uncertain in the face of technological change, policy-making, and the global economy that influences fuel prices. Thus, I recommend for further study of these and similar projections of the electric power sector to include a treatment of the uncertainty of cost and performance parameters by adding sensitivity analysis, or even more sophisticated uncertainty analysis that incorporates the key uncertainties into the modeling and delivers more robust decision-making.

In conclusion, the electric power sector in New England has an enormous transition ahead as it approaches the challenge to decarbonize. Whether decarbonization moves slowly with gradually increasing commitments, or on a path to deep decarbonization, we will see new low-carbon resources play a big role in meeting electricity demand in the future. GasCCS with high capture rates, if optimistic cost estimates are materialized around 2030, has the potential to dominate 55-85% of the generation mix once higher CES targets are required, and even independent of transmission expansions. Modest capacity expansion for gas pipelines into New England will be necessary under the scenarios where GasCCS is strongest, but secondary policy effects like electrification of home heating also have the potential to free up pipeline capacity in these scenarios. Adding transmission capacity will enable wind to play a bigger role on the path to high penetration of low-carbon resources. I have shown in my analysis that increasing transmission capacity within the region, and to a certain degree increasing interconnection with Canada as well, can unlock and take advantage of localized resources like wind power. I also found that Increasing transmission and interconnection capacity to levels that allocate optimal flows in almost all hours is worth considering. I thus recommend the further and more detailed study of the expansion of transmission capacities within New England, interconnection with Canada to make use of hydro resources, and their effect on the future of the electric power sector in New England under policy scenarios.

APPENDIX A – TECHNOLOGY MATCHING

Code EleMod	NREL ATB	Resource Group	Form EIA-860[21]	Capacity expansion	Comment
n01	Gas-CT	Gas	Natural Gas Fired Combustion Turbine	Yes	
n02	Gas-CC	Gas	Natural Gas Fired Combined Cycle	Yes	
n03	Gas-CCS	Gas	(new resource)	Yes	
n05	CoalOldScr (legacy)	Coal	Conventional Steam Coal	No	Data set from EIA AEO 2006. Compute existing capacity based on plant operating year (<1990).
n06	Coal-new	Coal	Conventional Steam Coal	Yes	Compute existing capacity based on plant operating year (>1990).
n07	Coal-IGCC	Coal	(new resource)	Yes	
n09	OGS (legacy)	Gas	Natural Gas Steam Turbine	No	Data set from EIA AEO 2006.
n10	Nuclear	Nuclear	Nuclear	Yes	
-	CofireOld	-	-	-	Data does not differ from CofireNew except SOx/NOx which is not tracked, and no future installments. Cut.
n12	CofireNew	Bio	Municipal Solid Waste	No	Ca. 1% of existing capacity. Similar operational characteristics than co-fire new, thus aggregate.
			Wood/Wood Waste Biomass	Yes	Compute existing capacity based on whether secondary fuel is listed.
n13	Dedicated	Bio	Wood/Wood Waste Biomass	Yes	Compute existing capacity based on whether secondary fuel is listed.
n14	Coal-CCS-30%	Coal	(new resource)	Yes	
n15	Coal-CCS-90%	Coal	(new resource)	Yes	
n16	Oil Combustion Turbine (legacy)	Oil	Petroleum Liquids	No	Apply data from Gas-CT with petroleum (DFO) as fuel price. Compute existing capacity based on prime mover (all except 'ST').
n17	Oil Steam Turbine (legacy)		Petroleum Liquids	No	Apply data from OGS with petroleum (DFO) as fuel price. Compute existing capacity based on prime mover (only 'ST').
HYD	Hydropower	Hydro	Conventional Hydroelectric	No	
solar	Solar - Utility PV	Solar	Solar Photovoltaic	Yes	

[21] *Italicized entries* indicate that generator stock was divided between two EleMod technologies.

wind	Land-Based Wind	Wind	Onshore Wind Turbine	Yes	
-	-	-	Landfill Gas	-	Insignificant current capacity (< .25%), and no future installments.
-	-	-	Natural Gas Internal Combustion Engine	-	Insignificant current capacity (< .25%). Future installments captured by Gas-CT.
-	-	-	Offshore Wind Turbine	-	Insignificant current capacity.

APPENDIX B – COST AND OPERATIONAL PARAMETERS FOR CONVENTIONAL RESOURCES

dtgt	Pmin	af	orfr	pf	hr	ef	eclf	capex	crf	fom	fca	vom	stupcost
*	Pu	pu	pu	$_MMBtu	MMBtu_kWh	ton_MMBtu	yrs	$_kW	%	$_kWyr	$_kWyr	$_kWh	$_kW
n01	0.0000	0.9200	0.0300	4.9726	0.0099	0.0531	35	882.2	0.08284	11.83	84.91	0.0069	0.0200
n02	0.0000	0.9000	0.0400	4.9726	0.0065	0.0531	35	1031.8	0.08284	10.22	95.69	0.0027	0.0750
n03	0.0000	0.9000	0.0400	4.9726	0.0075	0.0053	35	2153.6	0.08284	32.53	210.92	0.0069	0.0750
n04	0.4000	0.8460	0.0600	2.2769	0.0104	0.0930	60	99999.00	0.08284	999.00	9999.00	0.0101	0.1500
n06	0.4000	0.8400	0.0600	2.2769	0.0088	0.0955	60	3859.0	0.08284	31.86	351.52	0.0046	0.1500
n07	0.5000	0.8000	0.0800	2.2769	0.0088	0.0955	60	4140.9	0.08284	52.53	395.54	0.0074	0.1500
n09	0.4000	0.7927	0.1036	4.9726	0.0115	0.0540	50	99999.00	0.08284	999.0000	9999.00	0.0048	0.0750
n10	1.0000	0.9000	0.0400	0.5296	0.0105	0.0000	40	5979.0	0.08284	101.74	597.02	0.0022	1.0000
n12	0.4000	0.8300	0.0700	2.2769	0.0088	0.0955	60	4013.0	0.08284	31.86	364.28	0.0046	0.1500
n13	0.4000	0.8300	0.0900	2.9203	0.0135	0.0000	60	3888.8	0.08284	108.07	430.20	0.0054	0.1500
n14	0.5000	0.8000	0.0800	2.2769	0.0098	0.0669	60	5341.2	0.08284	68.13	510.57	0.0069	0.1500
n15	0.5000	0.8000	0.0800	2.2769	0.0118	0.0096	60	5906.1	0.08284	79.12	568.36	0.0093	0.1500
n16	0.0000	0.9200	0.0300	23.8000	0.0099	0.0531	50	99999.00	0.08284	999.00	9999.00	0.0069	0.0200
n17	0.4000	0.7927	0.1036	23.8000	0.0115	0.0540	50	99999.00	0.08284	999.00	9999.00	0.0048	0.0750

APPENDIX C – COST AND OPERATIONAL PARAMETERS FOR RENEWABLE RESOURCES

	af	fca	eclf	vom	ForOR	PlanOR
*	pu	$_kWyr	yrs	$/MWh	[p.u.]	[p.u.]
Wind	0.4010	187.189	20	0.00	0.00	0.00
Solar	0.1572	179.840	33	0.00	0.00	0.00
Hydro	1.0000	0.000	50	0.00	0.05	0.02

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