Impact of Utility-Scale Distributed Wind on Transmission-Level System Operations

C. Brancucci Martínez-Anido and B.-M. Hodge

National Renewable Energy Laboratory

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Technical Report
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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

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List of Acronyms

4HA	4-hour-ahead
CC	combined-cycle
DA	day-ahead
DG	distributed generation
GT	gas turbine
IC	internal combustion
ISO-NE	Independent System Operator–New England
NREL	National Renewable Energy Laboratory
RES	renewable energy sources
RT	real time
ST	steam turbine
WIND	Wind Integration National Data Set

Executive Summary

This report presents a new renewable integration study that aims to assess the potential for adding distributed wind to the current power system with minimal or no upgrades to the distribution or transmission electricity systems. It investigates the impacts of integrating large amounts of utility-scale distributed wind power on bulk system operations by performing a case study on the power system of the Independent System Operator–New England (ISO-NE). The study was performed by NREL and supported by the U.S. Department of Energy.

The analysis is performed by modeling the ISO-NE power system for the year 2010 using PLEXOS, a commercial production-cost model. The model is run for one scenario without wind power and eight scenarios with increasing distributed wind power penetrations (on an annual energy basis) up to 21.2%. The eight scenarios with different distributed wind power penetration levels are simulated with four different wind integration modeling approaches using curtailment and day-ahead (DA) and 4-hour-ahead (4HA) forecasts. In one approach, wind power generation is modeled allowing wind power curtailment, and it includes simulated DA and 4HA operational wind power forecasts. The other three modeling approaches do not allow wind curtailment in order to simulate the integration of utility-scale distributed wind turbines more similarly to how distributed generation is integrated today. The three modeling approaches in which curtailment is not allowed differ from each other to investigate the impact and value of wind power forecasting on transmission-level system operations. The four different modeling approaches are analyzed and compared to each other to simulate a more realistic case in which a system operator has neither visibility nor control over the turbines because of their distributed nature, and to simulate a case in which a system operator could curtail power generation and use wind power forecasts during the commitment of conventional power plants.

The integration of distributed wind in ISO-NE impacts the electricity generation mix in several ways. In absolute terms, the two largest changes are observed for gas- and coal-fired electricity generation. Both sources decrease their electricity output with increasing wind power penetration. Wind power forecasts reduce gas-fired electricity generation to a larger extent. If wind power forecasts are not considered, the over-commitment of gas power plants results in higher gas-fired electricity generation. On the other hand, if simulated operational wind power forecasts are used in the DA and 4HA power plant commitments, the resulting generation mix is very similar to the one corresponding to perfect wind power forecasts. In relative terms, the largest changes in the electricity generation mix caused by distributed wind power penetration correspond to a very large increase in the electricity output of oil-fired, gas turbine, and gas internal combustion generators when simulated DA and 4HA operational wind power forecasts are used. These power plants are used during few hours in the year and are characterized by their fast start-up and ramping capabilities. The uncertainty of wind increases their electricity output. The shares of nuclear and hydro in the electricity generation mix are not affected by wind power penetration. They are both committed in the DA market; and in the case of hydro, the ISO-NE model does not allow redispatching in the 4HA and RT simulations. On the other hand, increasing wind power penetration increases hydro pumping and decreases biomass electricity generation. ISO-NE's net electricity imports decrease with increasing distributed wind power penetration because of a decrease in electricity prices in ISO-NE when wind blows.

The integration of distributed wind also has an impact on the ramping of electricity generators. Hydro pumping power plants vary their output the most; nuclear and biomass power plants experience the fewest ramping events. The ramping of coal power plants increases with wind power penetration for all wind integration modeling approaches. On the other hand, the ramping of combined-cycle power plants increases with wind power penetration only when wind power forecasts are not used because of the over-commitment of generation. The ramping of gas steam turbine power plants increases with wind power penetration. The opposite is true when wind power forecasts are not used because of the over-commitment of electricity generators that have better and cheaper ramping capabilities.

From a transmission-level system operator's point of view, wind power curtailment remains very small for the highest wind power penetration scenarios analyzed in this study. The scenario with 21% wind power penetration shows a total wind power curtailment smaller than 0.7%. Nonetheless, the impact of wind power curtailment on electricity prices is more significant. If wind power curtailment is not allowed, negative electricity prices increase for higher wind power penetration levels. The largest number of negative electricity prices is observed when wind power forecasts are not considered because of the over-commitment of electricity generation.

CO_2 emissions decrease as distributed wind power penetration increases. The rate of decrease is smaller when wind power forecasts are not considered because of the over-commitment of electricity generation.

Electricity generation costs decrease as wind power penetration increases. As in the case of CO_2 emissions, the rate of decrease is smaller when wind power forecasts are not considered, even though wind power forecast errors increase start-up and shutdown costs while decreasing fuel costs. There is not a significant difference in electricity generation costs when perfect wind power forecasts are used (compared to the case in which simulated operational wind power forecasts are used).

This study shows that at low penetration levels distributed wind does not have major impacts on transmission-level system operations, even if a system operator does not have any visibility or control of the individual utility-scale wind power plants connected throughout the different distribution networks in ISO-NE. Nonetheless, as distributed wind power penetration increases, the impact on system operations increases as well. At the same time, the values of wind power curtailment and wind power forecasting increase, reducing the impact on transmission-level system operations and decreasing the total system operation costs.

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1 Introduction

This report presents a new renewable integration study that aims to assess the potential for adding distributed wind to the current power system with minimal or no upgrades to the distribution or transmission electricity systems. It investigates the impacts of integrating large amounts of utility-scale distributed wind power on bulk system operations by performing a case study on the power system of the Independent System Operator–New England (ISO-NE). The study was performed by NREL and supported by the U.S. Department of Energy.

The challenging goal of decarbonizing the power system is the major driver for the expected high penetrations of electricity generation from variable renewable energy sources (RES) forthcoming in the United States. Wind and solar are the most mature variable RES technologies, and their shares in the electricity generation mix are expected to increase significantly in the coming decades. Their variable and uncertain availability make them unique sources of electricity generation. Because of their distinctive natures, variable RES have been the subject of much consternation among utility operators and hence numerous grid and market integration studies. Examples of these are given below. Each of these studies focuses on different integration challenges, as well as on different geographical locations, and in the process examines different energy mixes, market structures, and other inherent power system characteristics.

The National Renewable Energy Laboratory (NREL) recently performed several renewable integration studies. For example, two phases of the Western Wind and Solar Integration Study have been completed: the first investigated the benefits and challenges of integrating up to 35% wind and solar energy in the Western Interconnection (GE Energy 2010); the second studied the impacts of the integration of wind and solar power on the fossil-fueled fleet by examining wear-and-tear costs and emissions from cycling (Lew et al. 2013). With regard to the Eastern Interconnection, the Eastern Wind Integration and Transmission Study examined the operational impacts of integrating up to 30% wind energy penetration on the power system (EnerNex 2011); and the Eastern Renewable Generation Integration Study, which is in progress, evaluates, among other issues, the ability of greater interregional cooperation, geographic diversity, and subhourly scheduling to provide operational flexibility (Bloom forthcoming). In addition, NREL has performed several other studies of smaller geographical regions that look at the detailed impacts of integrating renewable energy on the operations of a power system, such as recent studies on the drivers of the cost and price of operating reserves (Hummon et al. 2013), the economics of new transmission to deliver wind power from Wyoming to electricity customers in California (Corbus at al. 2014), and the impact of generator flexibility on electric system costs and the integration of renewable energy (Palchak and Denholm 2014).

Several other renewable integration studies have been performed during the past years in the United States and around the world. For example, Energy & Environmental Economics recently published a study that analyzed the integration challenges of a high-renewables portfolio in California (2014). Canada has also been the subject of analyzing options to integrate renewable energy (Hoicka and Rowlands 2011). Several European countries are world leaders in wind and solar integration, including Denmark, Germany and Spain. This, among other reasons, has led to multiple renewable integration studies in Europe (Hammons 2008; Schaber, Steinke, and Hamacher 2012; Steinke, Wolfrum, and Hoffmann 2013). Moreover, the integration of renewable energy in North Africa and the electrical interconnection to Europe have also been investigated (Haller, Ludig, and Bauer et al. 2012; Brancucci Martínez-Anido et al. 2013). In addition to renewable integration studies that consider both wind and solar energy sources, numerous wind-specific integration studies have also been published. One of the most studied topics regarding wind integration is the impact of wind power on the operation of a power system (Ummels et al. 2007, Strbac et al. 2007, Holttinen et al. 2011).

Distributed generation (DG) is one of the most widely investigated topics in renewables integration. Although the literature does not always provide a consistent definition of DG, a publicly accepted definition describes it as "electric power generation within distribution networks or on the customer side of the network" (Ackermann, Andersson, and Soder 2001; Pepermans et al. 2005). DG has been the subject of several research projects during the past decade. For example, Pecas Lopes et al. presented an overview of the issues concerning integrating DG into electric power systems (2007); Slootweg and Kling investigated the impact of DG on the dynamics of a test system (2002); and Coster et al. analyzed the effects of integrating DG on an existing distribution network by studying voltage control, grid protection, and fault events (2011). Dondi et al. reviewed the position of DG within the grid infrastructure as well as possible ways to improve interconnection while considering the technical standards in Europe and the United States (2002). A companion report to this work presented a general guide on the impacts of distributed wind on the distribution feeder and on the amount of wind power that can be added without adversely impacting the operation, reliability, and power quality of the feeder (Allen, Zhang, and Hodge 2013).

The study presented in this report complements the current literature and provides new insights about renewable integration, specifically distributed wind integration. We are not aware of any other study that investigates the impact of distributed wind on transmission-level system operations in an existing large transmission network with a detailed nodal production-cost model that includes load and wind forecasts as well as hundreds of distributed wind power plants. A recent International Energy Agency collaboration resulted in an overview of the impacts of large amounts of wind power on the design and operation of power systems, and the published report provided several recommendations for future wind integration studies (Holttinen et al. 2011). The study presented in this report meets many of them:

- "capturing the smoothed out variability of wind power production time series for the geographic diversity assumed and utilizing wind forecasting best practice for the uncertainty of wind power production"
- "examining wind variation in combination with load variations, coupled with actual historic utility load and load forecasts"
- "capturing system characteristics and response through operational simulations and modelling"
- "examining actual costs independent of tariff design structure"
- "the availability of high quality chronological synchronized data that captures the correlation with load data"

1.1 Background and Motivation

Solar power is the fastest growing variable RES technology of the past few years (Renewable Energy Policy Network for the 21st Century 2013), but wind power penetration has also increased greatly during the past decade, and wind has the largest global installed electricity generation capacity of all variable RES: 318 GW in 2013 compared to 39 GW in 2003 ("Global Statistics" 2014). By the end of 2013, the wind generation capacity in the United States amounted to 61 GW ("Global Statistics" 2014). The great deployment of wind has been largely driven by policy goals to reduce greenhouse gas emissions from electricity generation and to promote zero-emission electricity generation technologies. The cost of electricity generation from wind has decreased significantly during the past decade. The U.S. Energy Information Administration projects that onshore wind will be one of the electricity generation technologies entering service in 2018 with the lowest total system levelized cost (2014), as shown in Table 12 in Appendix A. On the other hand, offshore wind, even though it has a higher capacity factor, is expected to have a much higher total system levelized cost primarily because of its higher capital cost. Throughout this report, onshore wind will be referred to as wind, because we do not consider any offshore wind in this study.

One of the challenges of integrating wind generation into the power sector is that the geographical locations with the best wind resources are generally located relatively far from the load centers. Therefore, in many cases a substantial as well as uncertain transmission investment would need to take place to connect new wind farms to the electricity transmission network. For example, "an analysis conducted at the request of the six New England governors found that the cost to interconnect from 2,000 MW to 12,000 MW of wind power would be between $1.6 billion and $25 billion in transmission upgrades" (ISO-NE, 2013a) (compared to $6 billion spent on transmission investment since 2002 ["Key Facts" 2014]). In addition, transmission investments often have difficulties associated with the many regulatory and legal issues surrounding new transmission construction, which often causes delays and cost overruns.

However, the possibility of interconnecting small numbers of wind turbines to existing distribution lines would enable an increase in the amount of wind energy supplied without the need for expensive and time-consuming transmission expansions. This strategy helped enable Denmark and Germany to greatly expand their wind energy penetration during the 1990s and early 2000s. Even though the distribution networks in Germany and Denmark are generally more robust than they are in the United States (and necessary distribution system upgrades were performed in Denmark), there are some locations in the United States where large wind turbines could be added to the distribution network without incurring significant network investment or decreasing system reliability and power quality.

ISO-NE manages and operates the power system of a single balancing authority area formed by six states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The ISO-NE power system delivers electricity to 6.5 million households and businesses in a region with a population of 14 million. The highest historical peak demand of the ISO-NE power system is 28,130 MW (experienced on August 2, 2006) ("Key Facts" 2014). "Renewable Portfolio Standards and other environmental targets call for 30% of New England's projected total electric energy needs in 2020 to be met by renewable resources and energy efficiency"

(ISO-NE 2013a). In 2013, 6.76% of electricity demand in New England was met with renewable sources (excluding hydro): 1.37% wind, 0.09% solar, and 5.31% biomass (ISO-NE, 2013b).

Despite the present low wind power penetration, “New England has multiple wind-rich areas ripe for development, making renewable energy an exciting possibility for the region’s future” (ISO-NE, 2013a). Without considering the feasibility of siting wind turbines, New England holds a theoretical potential for developing more than 215 GW of onshore and offshore wind generation (GE Energy, EnerNex, and AWS Truepower 2010). As of January 2013, “approximately 40% of the proposed projects in the ISO’s Generator Interconnection Queue are wind-powered” (ISO-NE, 2013a).

1.2 Scope and Methodology

The aim of the study presented in this report is to assess the transmission-level impacts of utility-scale (2-MW turbines) distributed wind in New England. The analysis is performed by modeling the ISO-NE power system for the year 2010 using PLEXOS, a commercial production-cost model. The model is run for one scenario without wind power and eight scenarios with increasing distributed wind power penetrations (on an annual energy basis) up to 21.2%.

The eight scenarios with different distributed wind power penetration levels are simulated with four different wind integration modeling approaches using curtailment and day-ahead (DA) and 4-hour-ahead (4HA) forecasts. In one approach, wind power generation is modeled allowing wind power curtailment, and it includes simulated DA and 4HA operational wind power forecasts. The other three modeling approaches do not allow wind curtailment in order to simulate the integration of utility-scale distributed wind turbines more similarly to how distributed generation is integrated today. The three modeling approaches in which curtailment is not allowed differ from each other to investigate the impact and value of wind power forecasting on transmission-level system operations. The four different modeling approaches are analyzed and compared to each other to simulate a more realistic case in which a system operator has neither visibility nor control over the turbines because of their distributed nature, and to simulate a case in which a system operator could curtail power generation and use wind power forecasts during the commitment of conventional power plants.

2 ISO-NE PLEXOS Model

PLEXOS, a commercial production-cost model, was used to simulate the operation of the ISO-NE power system. The ISO-NE PLEXOS model has been designed to simulate the DA, 4HA, and real-time (RT) markets. ISO-NE does not have a 4HA market in place; however, we model it in PLEXOS to represent the security-constrained unit commitment at the last timescale useful to commit gas combined-cycle (CC) power plants as well as gas and oil steam turbines. The DA and 4HA markets are modeled with 1-hour time steps; the RT market can be modeled with time steps as low as 5 minutes. This section is structured as follows. The next four subsections provide details about the different elements of the ISO-NE PLEXOS model: the transmission network, generation, load, interconnections, and reserves. Finally, the last subsection presents the model validation.

2.1 Transmission Network

The ISO-NE model includes a wide representation of the ISO-NE transmission network: 3,314 nodes (or substations); 2,485 transmission lines; and 1,830 transformers. Table 1 shows the number of nodes and lines for the different voltage levels represented within the model.

Table 1. ISO-NE Model—Number of Nodes and Lines for Different Voltage Levels

Voltage Level (kV)	Number of Nodes	Number of Lines
345	157	186
230	32	30
120–191.5	10	6
115	1412	1677
99	80	0
69	171	186
44–48	97	90
34.5	200	125
24–33	44	18
23	187	75
14–22.8	97	1
13.8	505	66
< 13.8	322	25

The transmission data included in the PLEXOS model was initially provided by the Eastern Renewable Generation Integration Study (Bloom forthcoming) by extracting the transmission elements (nodes, lines, and transformers) from the Eastern Interconnection PLEXOS model developed within that study. The transmission data set was slightly modified by eliminating 9 nodes and 7 transmission lines in northern Maine that are connected to Canada and separated from the rest of ISO-NE transmission network. These few nodes correspond to less than 0.4% of the total New England load. Figure 1 shows a map of the ISO-NE transmission network, including nodes (red dots) and transmission lines (black lines).

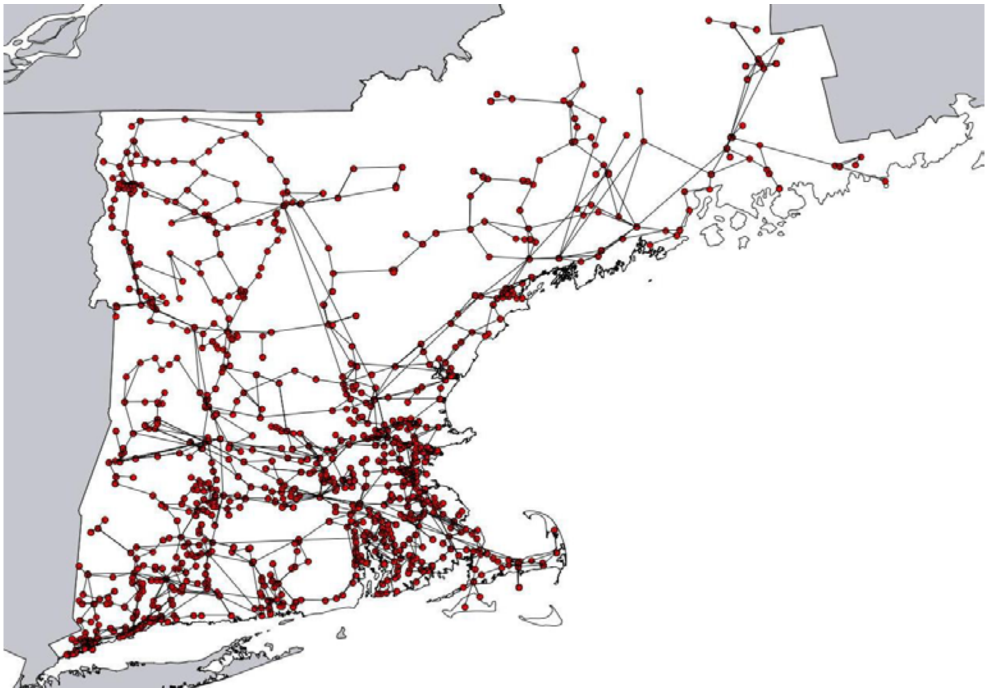

Figure 1. ISO-NE model—transmission network map

2.2 Generation

The ISO-NE model includes 468 electricity generators with a total installed capacity of 35,967 MW, excluding wind and solar generators. Distributed wind turbines are included and differ for each scenario with varying distributed wind power penetration levels. Details about wind sites for each scenario can be found in the next chapter. Table 2 shows the number of generators and installed capacity for each electricity generation source. Figure 26 in Appendix A plots the generators on a map. Electricity generation costs are calculated in the model using 2010 fuel prices published by EIA ("Fuel Prices" 2014).

Table 2. ISO-NE Model—Number of Generators and Installed Capacity for Each Generation Source

Generation Type	Number of Generators	Installed Capacity (MW)
Nuclear	5	4,878
Coal	19	3,740
Gas	159	17,101
Oil	131	5,691
Hydro	111	1,675
Pumped hydro	7	1,692
Biomass	36	844

Maintenance is considered only for nuclear generators by scheduling it during the time periods with the lowest load. The maintenance schedule is planned such that it is never conducted on two nuclear generators at the same time. The maintenance schedule of the other generators is not considered, because it has only a very small impact on the generators' capacity factor. In addition, maintenance does not impact the analysis of the results, and it is outside the scope of this study. For the same reason, unplanned outages of generators and transmission lines are not considered in the model.

In the DA and 4HA runs, DA and 4HA load and wind forecasts are considered. Nuclear, biomass and coal power plants are committed in the DA run; CC and steam turbines (STs) are committed in the 4HA run. All of these units may be redispatched within generator operating limits in the RT run. Hydropower plants are committed and dispatched in the DA run; hydro-pumping plants are committed in the DA run and redispatched in the 4HA and RT runs. All other power plants are committed and dispatched in the RT run.

2.3 Load

Hourly DA forecast and actual load time series used in the ISO-NE model were provided by ISO-NE ("Markets" 2014). Instead, simulated 4HA load forecasts have been created by considering the statistical properties of 4HA load forecasts observed in the Electric Reliability Council of Texas power system ("Load Data" 2014). Forecasting errors were normalized by the maximum demand to compare different power systems. Simulated forecast errors were created by randomly sampling the normalized 4HA forecasting error distribution from the Electric Reliability Council of Texas while ensuring that the forecasting errors had the same first-order autocorrelation properties as the actual 4HA forecasting errors. For the analysis of different scenarios with increasing distributed wind power penetration levels, 1-hour DA, 1-hour 4HA, and 5-minute RT electricity demand time series are used.

In addition to the transmission network data, the Eastern Interconnection PLEXOS model being used in the Eastern Renewable Generation Integration Study was the source for the load participation factors for each node in New England. Nine nodes, which account for less than 0.4% of total load (and are not directly electrically connected to the rest of the system), have been deleted (as explained in Section 2.1) from the original data set, and the load participation factors have been rescaled to sum to one.

The total electricity system load in New England in 2010 was 130,773 TWh, with a peak system load of 27,102 MW ("Markets" 2014). Figure 27 in Appendix A shows the nodes (red dots) that have load connected to them in the ISO-NE model.

2.4 Interconnections

The ISO-NE power system is interconnected to its neighboring regions: New Brunswick, Hydro Quebec, and the New York Independent System Operator. To model electricity flows to and from these regions in ISO-NE, we designed a methodology that takes advantage of the available data published by ISO-NE ("Markets" 2014). This data includes DA and RT locational marginal pricing for every hour of 2010 in six different zones of the three neighboring regions: New Brunswick, Hydro Quebec (Phase II and Higate), and New York Independent System Operator (Roseton, Northport, and Shoreham). In addition, the data includes hourly electricity flows among these six zones and ISO-NE. DA and RT locational marginal pricing in the six regions is used in the hourly PLEXOS simulations to establish the price at the six external nodes. DA forecasts for locational marginal pricing at the neighboring regions are considered in the DA run; actual (RT) values are assumed in the 4HA and RT runs.

The electricity flow on each interconnector for a given direction is limited to the maximum flow observed on the interconnector when the load in ISO-NE in 2010 was close to the observed one. In other words, the ISO-NE 2010 load was divided into 1-GW ranges, and for each of them the maximum electricity flow on each interconnector and direction was recorded from 2010 hourly time series. The maximum observed flows for each interconnector and direction differ for every load range and constrain the electricity flows on the interconnectors modeled within PLEXOS.

Some of the neighboring regions are connected to more than one transmission node in ISO-NE. In these cases, the ISO-NE model represents the external node as multiple nodes, each of them connected to one ISO-NE node. This is done to avoid unrealistic loop flows across the interconnectors. The locational marginal pricing is the same in the nodes representing the same neighboring region; however, the individual limits of electricity flows among these nodes and ISO-NE are proportional to the annual 2010 electricity flows on the specific interconnectors.

Figure 2 shows the six neighboring nodes as well as the interconnectors among these zones and the ISO-NE transmission network. External nodes that are connected to ISO-NE with multiple interconnectors are plotted in the map as only one external node; however, as explained above, the ISO-NE model considers them individual nodes. Each external node in the PLEXOS model includes a “physical contract” element. Based on the difference between its electricity price and the ISO-NE price, the “physical contract” may buy or sell electricity to ISO-NE.

Electricity flows on the interconnectors among ISO-NE and the neighboring regions are subject to a $3/MWh wheeling cost. This assumption avoids unrealistic cross-border flows when the electricity price difference among ISO-NE and neighboring regions is lower than $3/MWh.

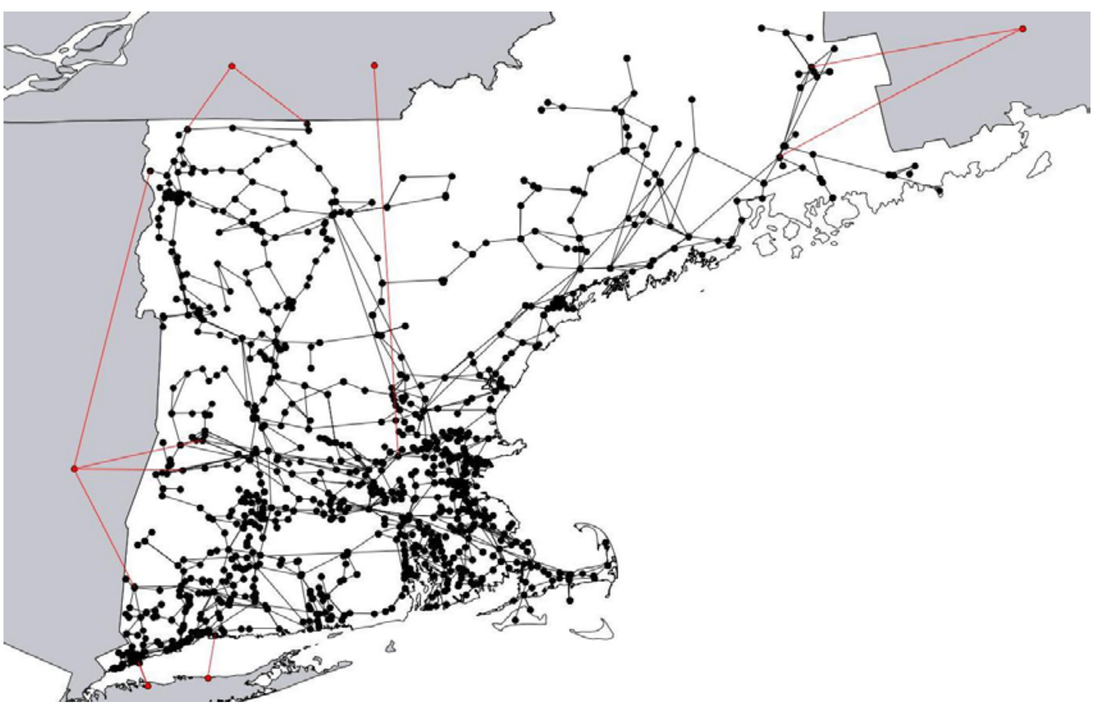

Figure 2. ISO-NE model—interconnectors map

2.5 Reserves

The ISO-NE model provisions contingency and regulation operating reserves in the three markets that it models: DA, 4HA, and RT. The model considers only the spinning part of the contingency reserve, which is a 10-minute product that is typically used to deal with unforeseen outages and which is defined to be half of 125% of the largest contingency in the system (a nuclear power plant with an installed capacity equal to 1,318 MW). The amount of spinning contingency reserve that is held during the entire year amounts to 824 MW. Nonspinning reserves are assumed to always be available; therefore, they are not included in the model.

Upward and downward regulation reserves are modeled as a 5-minute dynamic product and have a load and a wind component. It is important to note that ISO-NE does not currently hold any additional reserves specifically for wind power, but this could reasonably be expected to change with increased penetration levels. Load and wind forecast errors are assumed to be uncorrelated; therefore, the regulation reserve requirements are equal to the square root of the sum of the squares of the two components. The load component is equal to 1% of the forecasted (DA and 4HA runs) or actual (RT run) load. The wind component (only considered in scenarios with distributed wind generation) is based on 10-minute persistence forecast errors—or, in other words, on 10-minute wind ramps. The wind component of the regulation reserve requirements is based on 5-minute wind data of the three years prior to the reference year under study (2007 to 2009) available within the Wind Integration National Data Set (WIND) Toolkit (Draxl et al. 2013). All the 10-minute wind ramps for a given distributed wind scenario from 2007 to 2009 are plotted against the wind power generation at the time when they happen. The range of wind generation capacities is divided into bins of equal width. The 95th percentile of the wind ramps is calculated for each bin both for positive and negative ramps. A quadratic fitted curve is calculated for both the positive and negative wind ramps. Negative ramps represent upward regulation requirements, and positive ramps represent downward regulation requirements. Figure 3 shows the methodology for calculating the wind component of the regulation reserve requirements for one of the distributed wind scenarios described in the next chapter.

The equations of the two fitted curves are used to calculate the wind component of the upward and downward regulation requirements for a given scenario at each time step based on the forecasted wind generation (DA and 4HA runs) and the actual wind generation (RT run).

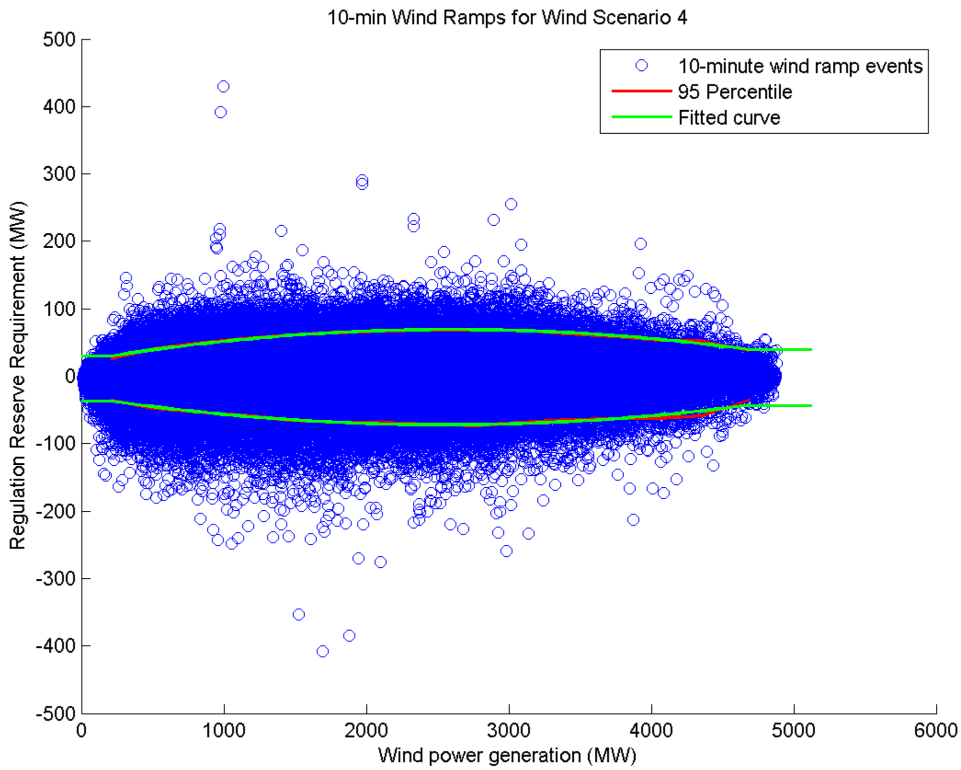

Figure 3. Upward and downward regulation requirements for Wind Scenario 4

2.6 Model Validation

In this section, the ISO-NE model is validated using 2010 data published by ISO-NE ("Markets" 2014). The ISO-NE model is run as described in the previous sections for the DA, 4HA, and RT markets with 1-hour time steps (the RT market is also run with 5-minute time steps). The only difference between the description in the previous sections and the validation run is that the model includes 25 wind farms to account for the relatively small installed wind capacity present in the ISO-NE power system in 2010. Wind forecasts are not considered in the validation run, because wind power represents only 0.4% of total energy production for the year.

To validate the ISO-NE model, the RT model (1-hour and 5-minute time steps) results are compared to 2010 data published by ISO-NE ("Markets" 2014). The following two subsections compare the model results of the energy mix and the hourly electricity prices in ISO-NE to the ISO-NE published data. In addition, the RT market is also run with 5-minute time steps to compare the model behavior when a smaller time step is used for the RT run. The validation was performed with hourly results because of the available ISO-NE hourly price statistics; however, the simulations performed within this study and presented in this report use RT time steps of 5 minutes. The third and last subsection presents the conclusions from the model validation analysis.

2.6.1 Energy Mix

Figure 4 shows the energy mix for the ISO-NE power system in 2010 for the published data and for the ISO-NE model results. Table 3 shows the numerical values of the results illustrated in Figure 4 as well as the results for the RT run with 5-minute time steps.

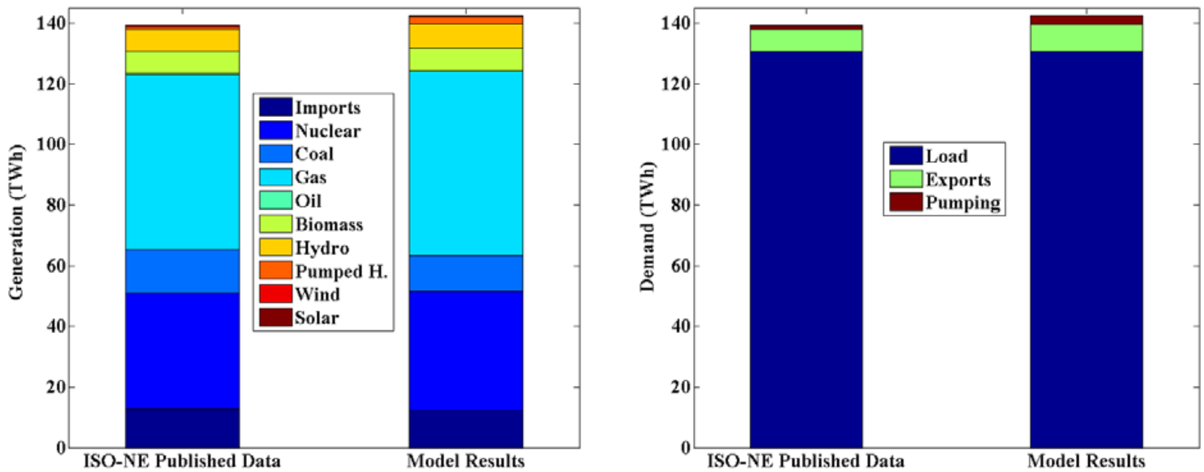

Figure 4. ISO-NE model validation—energy mix in 2010

Table 3. ISO-NE Model Validation—Energy Mix in 2010

		ISO-NE Published Data	Model Results (1 hour)	Model Results (5 Minutes)
Generation (TWh)	Imports	12.781	12.292	12.150
	Nuclear	38.364	39.198	39.201
	Coal	14.131	11.994	12.009
	Gas	57.584	60.865	60.728
	Oil	0.570	0.010	0.001
	Biomass	7.194	7.371	7.373
	Hydro	7.227	7.967	7.967
	Pumped Hydro	0.845	2.356	2.334
	Wind	0.491	0.491	0.491
	Solar	0.002	0.000	0.000
Demand	Load	130.773	130.772	130.466
	Exports	7.242	8.632	8.678
	Pumping	1.183	3.141	3.112

As Figure 4 and Table 3 show, the energy mix from the ISO-NE model is very similar to the one observed in ISO-NE in 2010. The largest differences occur in hydro pumping, coal-powered electricity generation, and electricity imports and exports. The model simulates almost three times more hydro pumping, 15% lower electricity generation from coal power plants, 4.9% lower electricity imports, and 20% higher electricity exports. The hydro pumping observed in the PLEXOS model is much higher than in reality, because the system is centrally optimized and external restrictions to hydro pumping are not modeled. Some of the reasons for the other discrepancies could be the electricity generation capacity mix included in the model as well as other model assumptions, such as the absence of bilateral contracts, fuel prices, power plant maintenance schedules, cross-border transmission capacities, and hourly electricity prices in the neighboring regions. The lower electricity generation from coal power plants and the lower net electricity imports are compensated in the model by 5.5% higher generation from gas power plants than that in the ISO-NE published data.

The ISO-NE model simulates lower electricity imports and higher exports than the ISO-NE data for 2010. The main reason for this is the way in which imports and exports are simulated within the model. Even if the imports and exports do not match exactly the published data, the overall net ISO-NE imports are simulated in an acceptable manner considering the planned application of the tool being validated. The differences among the model results and ISO-NE published data do not impact the applicability of the model for studying the impacts of distributed wind on transmission-level system operations. The goal for developing the ISO-NE model is not to recreate a perfect representation of the ISO-NE power system in 2010, but to have a model that realistically represents the operational characteristics of the ISO-NE power system. The two RT validation runs of the ISO-NE model with 1-hour and 5-minute time steps have very similar outcomes, demonstrating that the model is robust and that the analysis from both runs is valuable.

2.6.2 Electricity Prices

Table 4 shows a summary of key measures of electricity prices in ISO-NE in 2010 from ISO-NE published data as well as for ISO-NE model runs.

Table 4. ISO-NE Model Validation—Electricity Prices in 2010

	ISO-NE Published Data	Model Results (1 Hour)	Model Results (5 Minutes)
DA mean price ($/MWh)	48.90	44.72	44.72
RT mean price ($/MWh)	49.58	47.60	49.30
Mean RT price 1-hour volatility	7.21	5.49	-
Standard deviation RT price 1-hour volatility	14.21	10.89	-

Table 4 shows that the 2010 ISO-NE mean RT electricity price simulated by the ISO-NE model is 4% lower than the observed value when the RT market is run with a 1-hour time step. In the case of 5-minute time steps, the difference is lower than 0.6%. In addition, the ISO-NE model simulates the volatility of electricity prices to a lower extent than what is observed. Volatility is measured as the hour to hour changes in electricity prices. The main reason RT electricity prices are lower and have lower volatility is because of the absence of maintenance for most generators and because of forced generator and line outages. We observed slightly higher prices and volatility when including scheduled maintenance. However, as explained in the previous section, the simulations presented in this report consider maintenance only for nuclear generators for the sake of simplicity and because they do not impact the analysis of the results or the purpose of this study.

During the majority of the hours of 2010, the ISO-NE model simulates electricity prices in ISO-NE very similarly to the actual observation values. An example of a period during which the model represents electricity prices in a very precise manner is provided in Figure 5. Both electricity price valleys and peaks are accurately represented by the model.

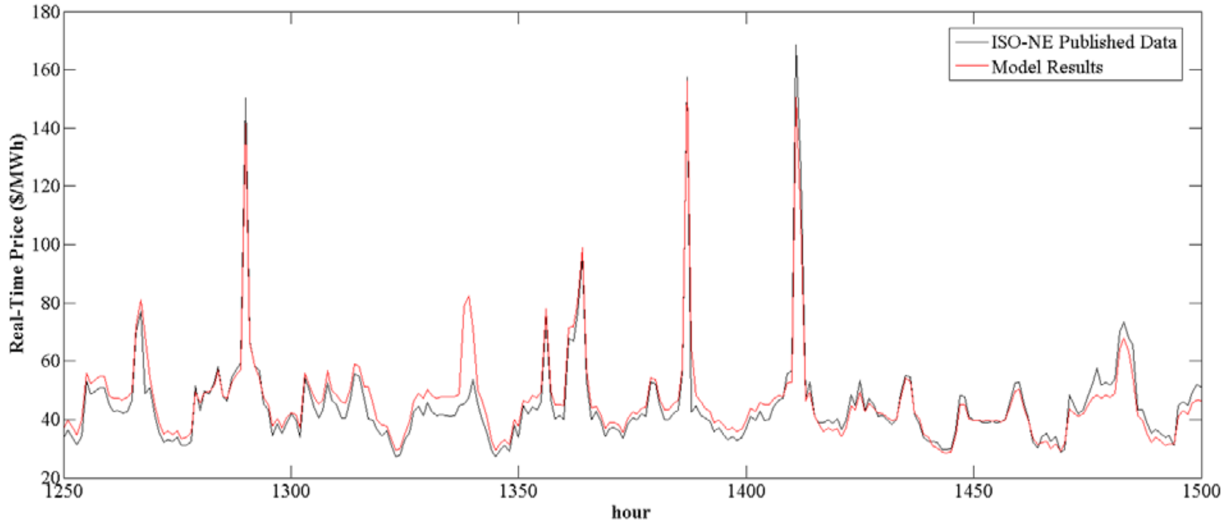

Figure 5. ISO-NE model validation—electricity prices (1)

However, for some hours of the year, the electricity prices simulated by the ISO-NE model do not correlate as well to real electricity prices observed in ISO-NE in 2010. Figure 6 shows an example of a period during which the model does not accurately simulate electricity prices.

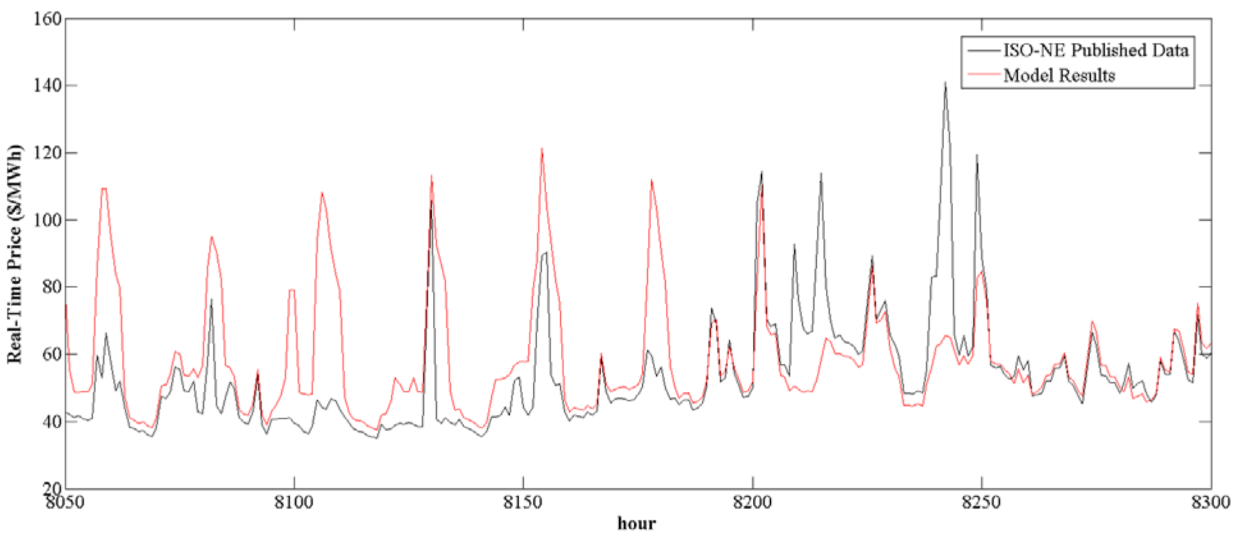

Figure 6. ISO-NE model validation—electricity prices (2)

During 75% of the hours, the differences among the hourly electricity prices observed in ISO-NE in 2010 and the prices simulated by the ISO-NE model are lower than 10%. Moreover, for 75% of the hours in 2010, the differences are lower than 10 $/MWh.

Figure 7 shows the load duration curve for the RT electricity prices in 2010 as published by ISO-NE and simulated by the ISO-NE model with 1-hour time steps. As shown, the two curves are very similar, and they coincide for the majority of the hours in the year. In addition, the hour of the highest electricity price simulated by the model coincides with the ISO-NE published data and its value, even though it is slightly lower, is very close to what was observed. The excellent correlation is partly due to the way in which electricity exchanges between ISO-NE and the neighboring regions are modeled, which includes the DA and RT electricity prices in the neighboring regions.

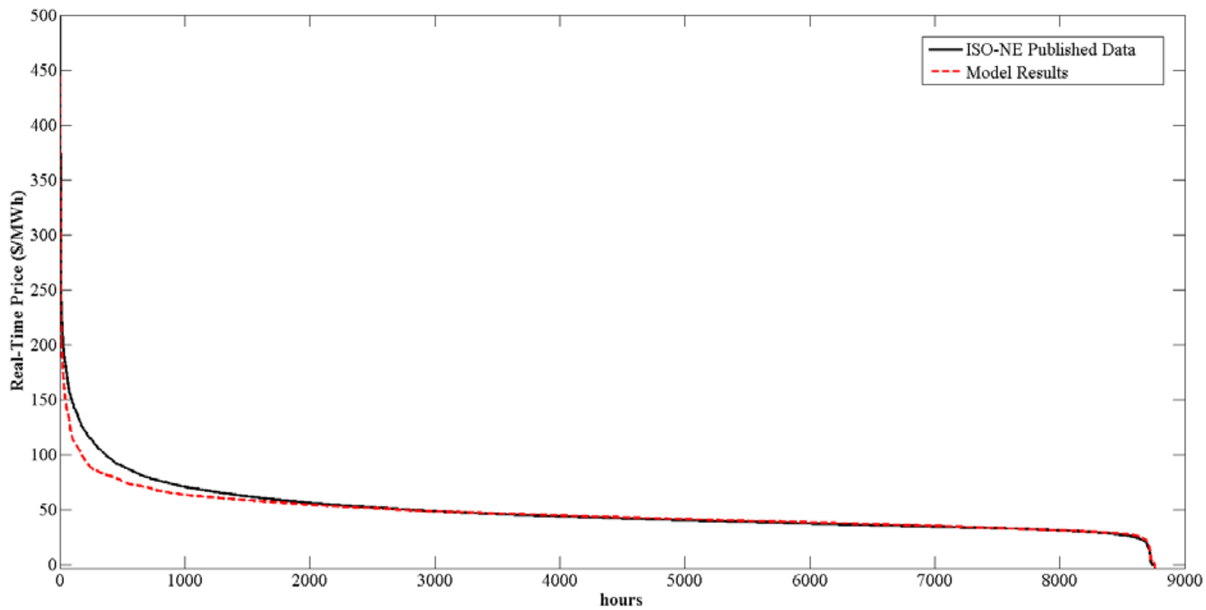

Figure 7. ISO-NE model validation—load duration curve of RT price

The accurate and validated simulation of electricity prices confirms the applicability of the model for studying the impacts of distributed wind on transmission-level system operations. The operational characteristics of the ISO-NE power system are well simulated by the model given the energy mix results presented in Section 2.5.1 and the close mean electricity prices and price volatility among the ISO-NE published data and the model results.

2.6.3 Model Validation Conclusion

The validation of the ISO-NE PLEXOS model is based on comparisons of the model results to 2010 data published by ISO-NE. The results presented in the two previous subsections show that the model has very good agreement on the shares of generation coming from each source when compared to ISO-NE published data. In addition, the electricity price signals are very similar for most of the time periods. In conclusion, the ISO-NE model presented in this report is a viable and valuable tool for studying the impacts of distributed wind on bulk system operations in the ISO-NE power system.

3 Distributed Wind Scenarios

This chapter describes the wind site selection methodology used to design different distributed wind scenarios with varying wind power penetration levels, ranging from 1.95% to 21.21%. The two sections of this chapter provide details on the wind site selection methodology and the differences among the eight distributed wind scenarios used as inputs to the production-cost model of the ISO-NE power system.

3.1 Wind Site Selection Methodology

Suitable locations for distributed wind power turbines depend both on geographical and network constraints. For example, wind turbines are more likely to be connected to the distribution network in rural areas because of the difficult permitting issues in urban areas. Moreover, wind resource and some terrain features are important considerations when choosing a suitable site for a utility-scale wind turbine. With regard to network conditions, the voltage level and other feeder characteristics, such as rating and length, are important considerations when selecting suitable sites for distributed wind turbines. More information about this can be found in an NREL study on the impact of wind turbines on distribution feeders (Allen, Zhang, and Hodge forthcoming).

The recent Wind Integration National Data Set (WIND) Toolkit (Draxl et al. 2013), funded by the U.S. Department of Energy Wind Program, is the source of wind data for the distributed wind site selection exercise as well as for the production-cost modeling. The WIND Toolkit was created by 3TIER using a mesoscale numerical weather prediction model run on a 2-km by 2-km grid with 5-minute resolution from 2007 to 2013. It was produced with the Weather Research and Forecasting model version 3.4.1 (Skamarock et al. 2008). The toolkit provides data for more than 120,000 onshore and offshore wind power production sites in the United States. For each suitable wind site, the available data includes a 5-minute wind power production time series and simulated operational forecasts for 1-hour-, 4-hour-, 6-hour-, and DA forecast horizons for the entire 7-year period.

Several selection criteria were considered in the WIND Toolkit site selection process with the goal to select likely locations. First, existing wind power plants as well as previous locations examined in the Western Wind and Solar Integration Study Phase 2 (Lew et al. 2013) and Eastern Wind Integration and Transmission Study (EnerNex 2011) were included. Each site was defined by a 2-km by 2-km grid cell in the numerical weather prediction data set, and it was assumed that eight 2-MW wind turbines was the maximum that could be accommodated per grid cell. Sites were excluded based on environmental and land-use conditions. For example, most federal lands, including U.S. National Park Service and U.S. Fish and Wildlife Service managed lands, open water areas, areas with a slope greater than 20%, and areas within a buffer area of developed land and airports were not considered. In addition to these exclusions, the onshore site selection methodology considered 3TIER’s 90-m continental U.S. wind resource data set for mean annual speeds to assign an effective MWh value to each grid cell. These values were ranked, and the best were chosen to create a database with more than 100,000 onshore sites that enables users to define plant build-outs by clustering sites. For the current study, the site selection methodology is described in this report, and offshore sites are not considered.

The WIND Toolkit does not consider any constraint based on the location and characteristics of existing transmission and distribution networks. Therefore, we developed a mixed-integer linear optimization model coded in the General Algebraic Modeling System (2014) (using the CPLEX solver [IBM 2014]) to select suitable wind sites from the WIND Toolkit to be connected to the ISO-NE power system for several scenarios with varying penetration levels while considering network constraints. The objective function of the optimization model is the maximization of the distributed wind power penetration level under the network constraints assumed in each scenario.

Table 5 provides a summary of the onshore wind site locations present in the WIND Toolkit database that are located in New England and from which a smaller number of wind sites are selected for each of the scenarios based on network constraints. Table 5 provides the number of sites, the total wind power capacity, and the mean wind capacity factor (from 2007 to 2012) for New England as well as for each of the six states that comprises it. The mean wind capacity factors are higher than they were in previous data sets, because a turbine hub height of 100 m was assumed, rather than 80 m or 90 m. For further information on the power data and the limitations of the WIND Toolkit, please see King and Hodge (2014).

Table 5. Summary of WIND Toolkit Data Set for New England

State	Number of Sites	Total Wind Capacity (MW)	Mean Wind Capacity Factor
Connecticut	110	1,258	0.458
Maine	1142	15,558	0.464
Massachusetts	512	5,810	0.464
New Hampshire	404	5,452	0.471
Rhode Island	126	1,492	0.453
Vermont	444	6,200	0.461
New England	2,738	35,770	0.464

The optimization model considers the current topology of the ISO-NE transmission network, and it constrains wind site locations based on several network characteristics, such as voltage level and feeder rating and length. The feeder rating is assumed to be equal to the peak load at each transmission node. Feeder length is assumed to be equal to or longer than the distance between a wind site and the transmission node to which it is connected.

A total of eight distributed wind scenarios with increasing distributed wind power penetration levels have been designed. For each scenario, selected sites are allowed to be connected only to transmission nodes with a voltage level equal to or lower than 69 kV. We assume that 69 kV is the voltage level at which the transmission and the distribution networks intersect. In reality, this may not always be the case; but given the unavailability of distribution network data, it has been assumed that anything at or lower than 69 kV is considered part of the distribution network at which distributed wind turbines can be connected to the grid.

The maximum distance between a wind site and the transmission node to which it is connected varies for each scenario to allow different distributed wind power penetration levels. Nodes that do not have any load are not allowed to have any distributed wind site connected to them; therefore, distributed wind sites are constrained to locations in rural (but populated) areas. (Urban areas are already neglected in the site selection methodology inherent in the WIND Toolkit data set.) The sum of the capacities of the wind sites connected to the same transmission node is limited to the peak load on that node for the lowest five wind power penetration scenarios. For the remaining three high-penetration scenarios, the sum of the capacities of the wind sites connected to the same transmission node is limited to two, three, and four times the peak load on that node. These three high-penetration scenarios are designed to study higher distributed wind power penetration levels while assuming that the distribution network below these nodes could be upgraded to accommodate DG with a capacity larger than the rated peak load.

Moreover, each scenario is forced to include the wind sites of the previous scenario—or, in other words, successive scenarios include the wind sites of all lower penetration scenarios as well as the additional wind (i.e., the wind sites in Scenario 1 are a subset of the wind sites in Scenario 2).

3.2 Distributed Wind Scenarios

This section describes the differences among the eight distributed wind scenarios designed to be used as inputs to the production-cost model of the ISO-NE power system. Table 6 shows the different network constraints assumed for each scenario. Constraint 1 is equal to the maximum distance between a wind site and the transmission node to which it is connected; Constraint 2 corresponds to the maximum ratio between the sum of the capacities of the wind sites connected to a node and the peak load at the node.

Table 6. Network Constraints for Each Distributed Wind Scenario

Scenario	Constraint 1 (Degrees Latitude-Longitude)	Constraint 2
SC1	0.025 (approx. 2.8 km)	1
SC2	0.050 (approx. 5.6 km)	1
SC3	0.075 (approx. 8.3 km)	1
SC4	0.100 (approx. 11.1 km)	1
SC5	0.125 (approx. 13.9 km)	1
SC6	0.125 (approx. 13.9 km)	2
SC7	0.125 (approx. 13.9 km)	3
SC8	0.125 (approx. 13.9 km)	4

Table 7 shows the distributed wind power penetration level, the number of wind sites, the installed wind capacity, and the mean wind capacity factor (from 2007 to 2012) for each distributed wind scenario.

Table 7. Penetration Level, Number of Wind Sites, Installed Wind Capacity, and Mean Wind Capacity Factor for Each Distributed Wind Scenario

Scenario	Penetration Level (%)	Number of Wind Sites	Installed Wind Capacity (MW)	Mean Wind Capacity Factor
SC1	1.95	87	690	0.432
SC2	4.96	201	1,718	0.439
SC3	6.96	269	2,398	0.441
SC4	8.62	325	2,978	0.441
SC5	10.40	373	3,556	0.444
SC6	15.61	506	5,264	0.448
SC7	18.90	590	6,336	0.450
SC8	21.21	641	7,074	0.451

Table 8 provides the installed wind capacity for the six New England states for each distributed wind scenario.

Table 8. Installed Wind Capacities (MW) for the Six New England States for Each Distributed Wind Scenario

State	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
Connecticut	88	174	342	468	564	610	624	656
Maine	48	74	132	244	280	580	698	782
Massachusetts	468	1,188	1,428	1,568	1,762	2,284	2,682	2,922
New Hampshire	52	114	226	316	382	612	788	906
Rhode Island	18	110	180	252	388	672	824	900
Vermont	16	58	90	130	180	506	720	908
New England	690	1,718	2,398	2,978	3,556	5,264	6,336	7,074

Maine is the largest geographic area, and it has the best wind resource of all of the states in New England, given its high wind capacity factors and the numerous potential locations for installing distributed wind turbines. As shown in Table 8, Maine does not have the highest installed distributed wind capacity in all eight scenarios, because it is constrained by its smaller population and thus its limited network access. Maine would have a much higher distributed wind capacity in all scenarios if transmission investment were allowed. The maps in Figure 28 to Figure 35 in Appendix B show the distributed wind site locations for each distributed wind scenario.

4 Results

To study the impact of distributed wind on transmission-level system operations, different scenarios are simulated by modeling the ISO-NE. These include one scenario without wind power (SC0) and eight scenarios with increasing distributed wind power penetration levels, from 1.95% to 21.2% (SC1 to SC8), as detailed in Section 3.2.

The eight scenarios with different distributed wind power penetration levels are simulated with four different wind integration modeling approaches using curtailment and DA and 4HA forecasts. Multiple approaches allow investigating the impact of increasing distributed wind power penetration on transmission-level system operations for different wind integration hypotheses. In the base case approach, wind power generation is modeled to allow wind power curtailment, and it includes simulated DA and 4HA operational wind power forecasts from the WIND Toolkit described in Section 3.1. The other three modeling approaches do not allow wind curtailment to simulate more realistic integrations of utility-scale wind turbines distributed throughout the distribution networks in ISO-NE. The system operator may not be able to easily control hundreds of individual wind sites, each with a maximum installed capacity of 16 MW—the scenario with the highest wind power penetration level (SC8, 21.2%) includes 641 individual wind power plants with a total installed wind capacity of 7,074 MW. The three modeling approaches in which curtailment is not allowed have different wind power forecasts to investigate their impact and value in transmission-level system operations. One includes simulated DA and 4HA operational wind power forecasts (as in the base case). Another does not include any wind power forecast in the DA and 4HA unit commitment runs. The last includes perfect DA and 4HA wind power forecasts. Table 9 lists the four wind integration modeling approaches and their differences. The details of the ISO-NE model common to every run presented in this chapter are provided in Chapter 2.

Table 9. Wind Integration Modeling Approaches

Modeling Approach	A (Base Case)	B	C	D
Wind power curtailment allowed	Yes	No	No	No
DA and 4HA wind power forecasts	Simulated operational	Simulated operational	None	Perfect

This chapter presents the results of 33 different runs: one run for the scenario without wind power and four different runs for each of the eight distributed wind scenarios.

The presentation and the discussion of the results are structured such that each following section investigates the impact of increasing distributed wind power penetrations on a different transmission-level system operation variable. These are analyzed in the following order:

- Electricity generation mix
- Electricity exchanges
- Ramping of electricity generators
- Wind power curtailment

- CO_2 emissions
- Electricity generation cost
- Electricity prices

Studying each of these system variables does not always include the analysis of the results of the 33 different runs. To study the impact of distributed wind on a specific system variable, the results from the eight wind power penetration scenarios are analyzed for different wind integration modeling approaches (summarized in Table 9) only if their results have significant differences.

4.1 Electricity Generation Mix

Figure 8 shows the impact of increasing the penetration of distributed wind on the annual electricity generation mix in ISO-NE for the wind integration modeling approach that includes simulated DA and 4HA operational wind power forecasts but excludes wind curtailment (Type B, see Table 9). The figure showing the electricity generation mix for the modeling approach that includes simulated DA and 4HA operational wind power forecasts as well as wind curtailment (Type A) does not show any significant differences in generation mix and is therefore not reported. Figure 8 shows the electricity generation mix for the scenario without wind (SC0) and for the eight distributed wind power penetration scenarios (SC1-B to SC8-B).

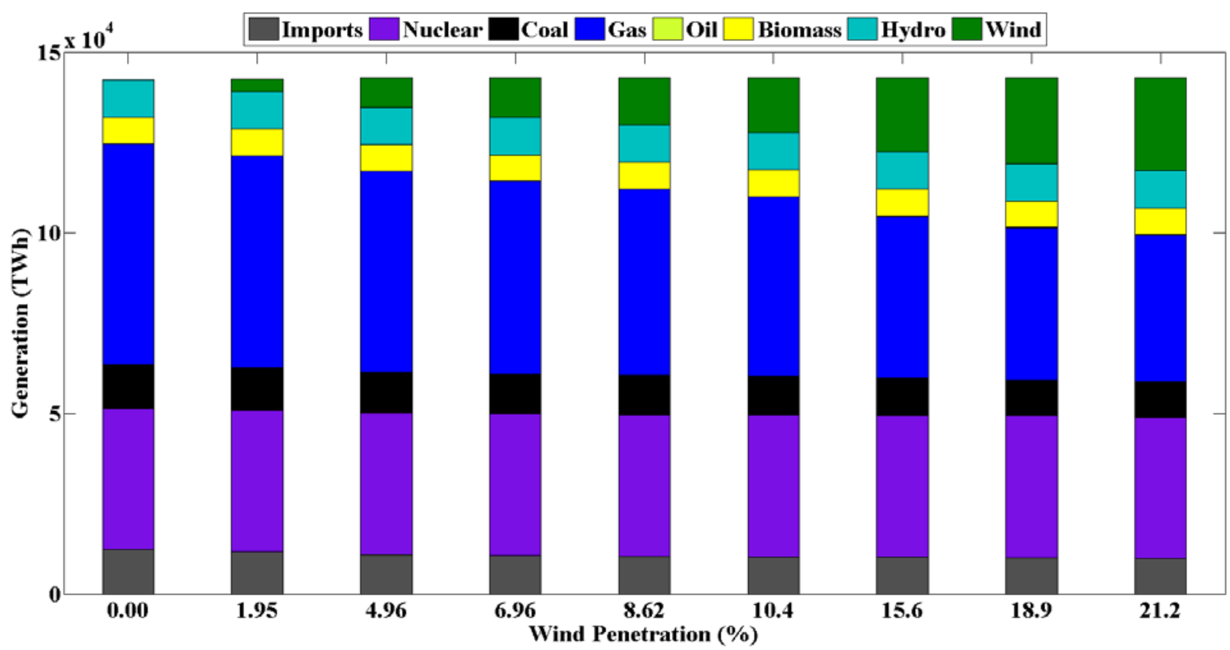

Figure 8. Electricity generation mix (SC0 and SC1-B to SC8-B)

Increasing wind power penetration gradually decreases the share of other electricity generation sources. The two largest changes are observed for gas- and coal-fired electricity generation; gas is the energy source displaced the most. In the scenario with the highest wind power penetration (SC8-B, with 21.2% wind power penetration), gas electricity generation is 34% lower than it is in the scenario without wind (SC0), from 61 TWh to 41 TWh. Coal electricity generation, instead, decreases by 18%, from 12 TWh to 9.9 TWh. Biomass electricity generation also decreases by 2%, from 7.37 TWh to 7.23 TWh. The shares of nuclear and hydro in the electricity generation mix are not affected by wind power penetration. They are both committed in the DA market; and in the case of hydro, the ISO-NE model sets the dispatch in the DA market, and it cannot be redispatched in the 4HA and RT simulations.

Figure 9 shows the annual electricity generation mix in ISO-NE for the modeling approach in which wind power forecasts are not considered (Type C). In this case, the DA and 4HA power plant commitments are scheduled without considering any wind power, therefore over-committing generation capacity when wind turbines generate electricity in the RT run.

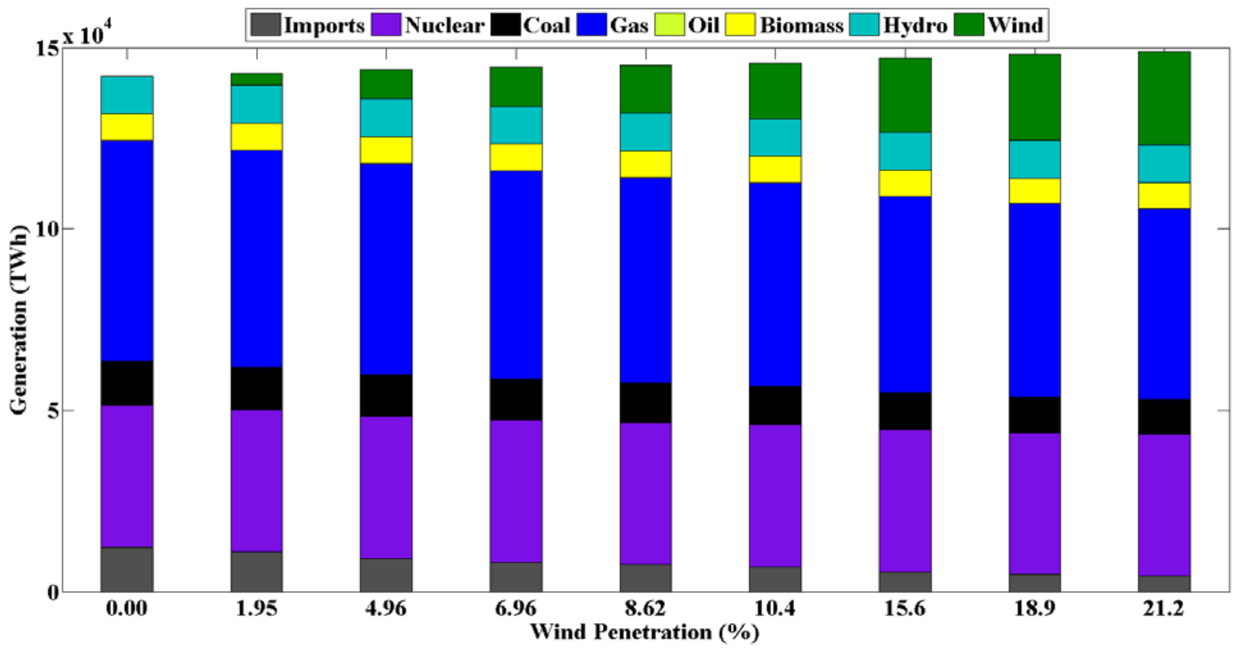

Figure 9. Electricity generation mix (SC0 and SC1-C to SC8-C)

In this case, the two largest changes are also observed for gas- and coal-fired electricity generation; however, gas-fired electricity generation is reduced to a much lower extent. In the scenario with the highest wind power penetration (SC8-C), gas electricity generation is 14% lower than it is in the scenario without wind (SC0), from 61 TWh to 53 TWh. The lower decrease in gas-fired electricity generation caused by the integration of distributed wind is the result of over-committing gas-fired power plants in the 4HA run because of the lack of wind power forecasts.

Coal electricity generation, instead, decreases similarly as that shown in Figure 8, from 12 TWh to 9.7 TWh. The reduction of biomass electricity generation increases but remains very small, from 7.37 TWh to 7.23 TWh. As in the previous case, the shares of nuclear and hydro in the electricity generation mix are not affected by wind power penetration. Nuclear generation decreases by only 0.68%, with a 21.2% wind power penetration (SC8-C), compared to the case without wind power (SC0). In the previous case, the reduction was only 0.15%.

Figure 10 shows the annual electricity generation mix in ISO-NE for the modeling approach with perfect wind power forecasts (Type D). In this case, the DA and 4HA power plant commitments are scheduled more efficiently because of the lack of wind power forecast errors. The only uncertainty that the power system deals with in the RT is provided by the load forecast errors. In other words, wind uncertainty is not modeled in this set of runs.

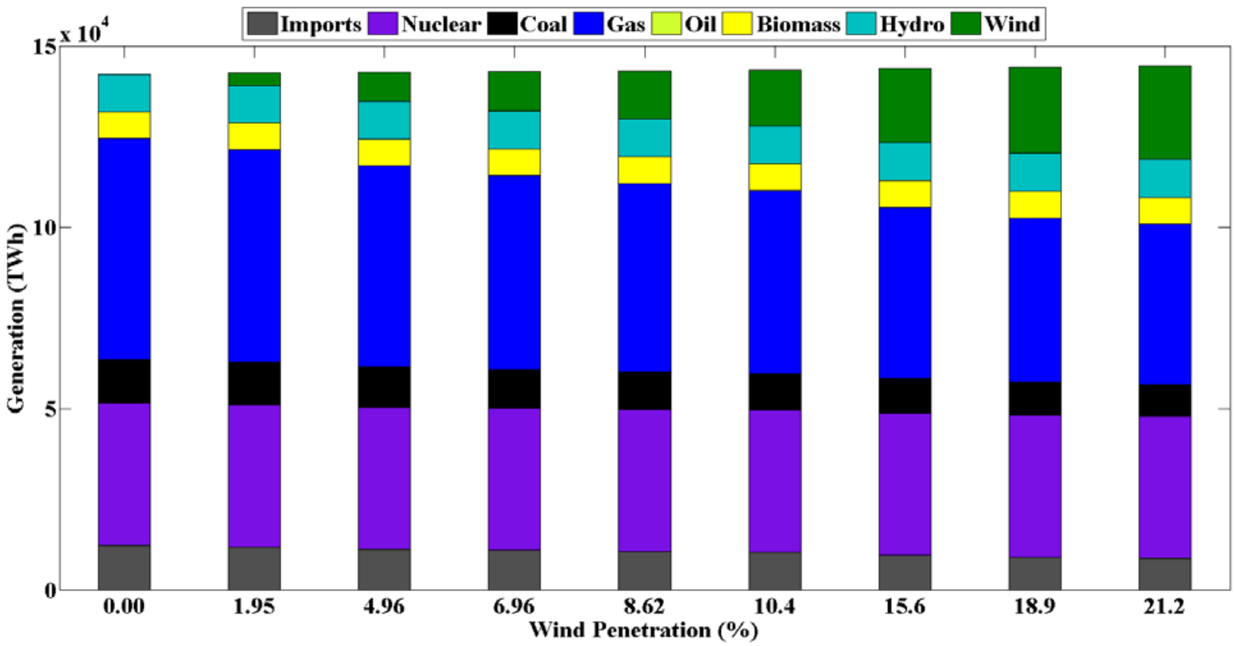

Figure 10. Electricity generation mix (SC0 and SC1-D to SC8-D)

In this case, the two largest changes are also observed for gas- and coal-fired electricity generation; however, coal-fired electricity generation is reduced to a larger extent than it is in the two previous cases. In the scenario with the highest wind power penetration (SC8-C), gas electricity generation is 28% lower than it is in the scenario without wind (SC0), from 61 TWh to 44 TWh. Coal electricity generation, instead, decreases by 26%, from 12 TWh to 8.9 TWh. The relative reduction in fossil-fueled electricity generation as a result of increasing wind power penetration is more evenly distributed among gas- and coal-fired electricity generators when perfect wind power forecasts are assumed. In this case, biomass electricity generation decreases by less than 1%, and the shares of nuclear and hydro in the electricity generation mix are not affected by wind power penetration, as shown in Figure 8.

Hydro pumping, included in the hydro category together with conventional hydropower as shown in Figure 8 to Figure 10, is committed in the DA, but it can be redispatched in the 4HA and RT simulations. Figure 11 shows how distributed wind impacts hydro pumping moderately. For the four different wind integration modeling approaches, the ISO-NE model results show an increase in hydro pumping when the distributed wind power penetration level increases. The largest rate of increase is observed when the model assumes perfect DA and 4HA wind power forecasts. In this case, hydro pumping is 13.2% higher in the scenario with a wind power penetration of 21.2% (SC8-D) than it is in the scenario without wind (SC0).

Wind power forecast errors impact the redispatching of hydro pumping plants, lowering their electricity output between DA and RT. If perfect wind power forecasts are used, hydro pumping varies less than it does in the DA dispatch, and therefore it increases more with wind power penetration.

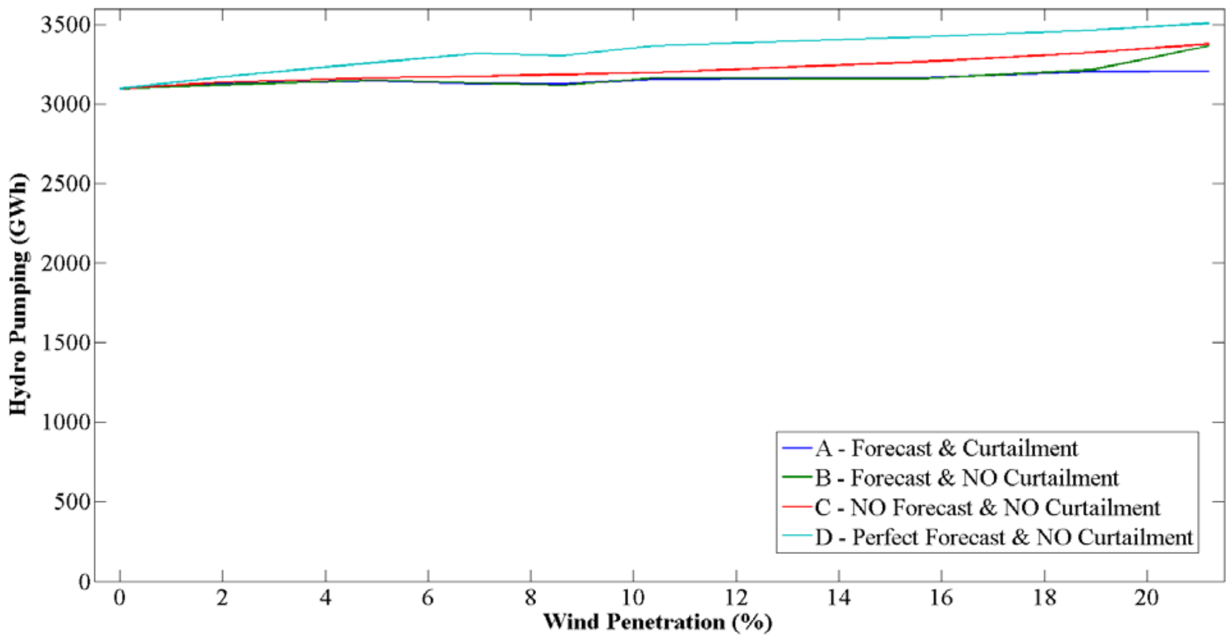

Figure 11. Hydro pumping

In addition to hydro pumping, wind power penetration also increases the share of some electricity generation sources that are used during only a few hours of the year; therefore, they are not noticeable in Figure 8 to Figure 10. The impact of the integration of distributed wind on these electricity generators varies for the different wind integration modeling approaches.

Even though, as shown in Figure 8 to Figure 10, gas-fired electricity generation is largely displaced by the integration of distributed wind, not every gas power plant decreases its electricity output. Gas power plants are divided into four categories: CC turbines represent the largest category, with more than 90% of the share of gas-fired electricity generation; STs represent the second largest category, with most of the remaining share; gas turbines (GTs) and internal combustion (IC) power plants represent only 0.05% of the share of gas-fired electricity generation in the scenario without wind power (SC0). However, as shown in Figure 12, GT and IC power plants, unlike CCs and STs, significantly increase their electricity generation with higher wind power penetrations when simulated DA and 4HA operational wind power forecasts are used (Type A and Type B). If wind power forecasts are not considered (Type C), electricity generation from GT and gas IC power plants decreases to zero as wind power penetration increases because of the over-commitment of gas power plants in the 4HA simulation. On the other hand, in the case in which perfect wind power forecasts are considered, electricity generation from GT and gas IC power plants increases, but to a much smaller extent than when simulated operational wind power forecasts are considered. The higher electricity generation of gas GT and IC power plants is driven by wind power forecast errors, especially in the 4HA simulation when CC power plants are committed. Wind power forecast errors are counteracted by the fast start-up and ramping of GT and gas IC generators. If wind power forecasts are not considered, the system experiences an over-commitment of generation. The need for electricity generation from GT and IC power plants is substituted by the other electricity generation sources that are over-committed in the DA and 4HA simulations.

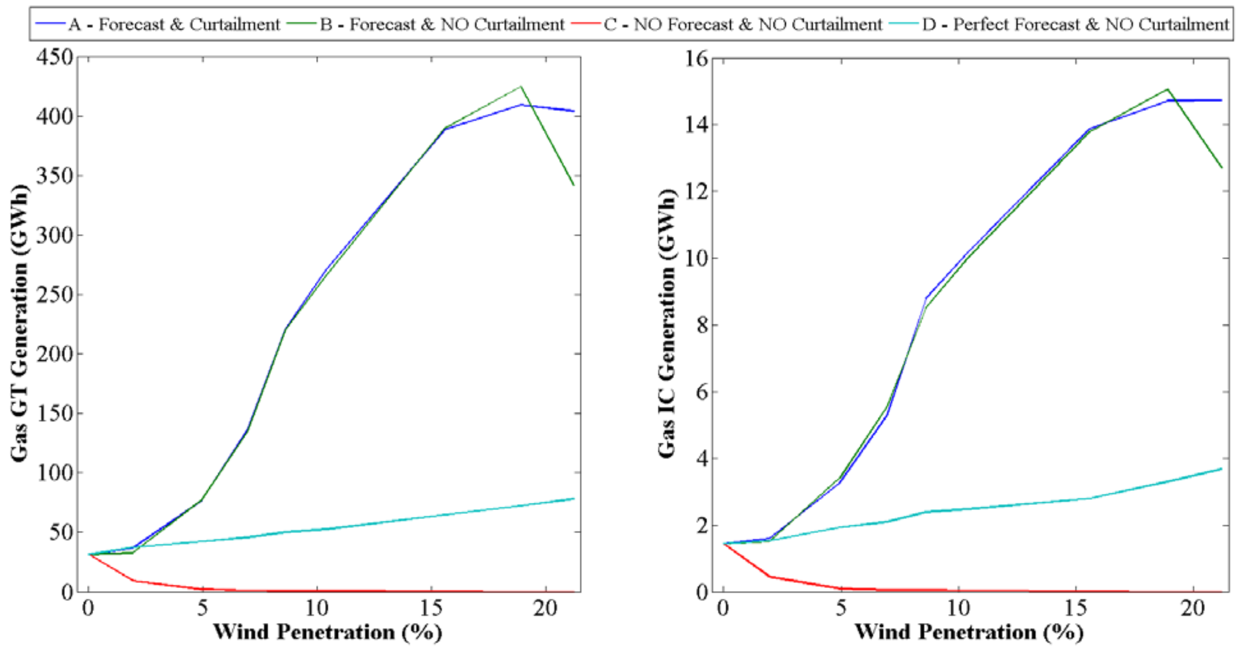

Figure 12. GT and gas IC generation

Oil represents the smallest share in the electricity generation mix in every scenario, as shown in Figure 8 to Figure 10. Oil-fired electricity generators follow very similar behavior as that of GT and gas IC power plants when subject to increasing distributed wind power penetration, as shown in Figure 13. Oil-fired power plants significantly increase their electricity generation with higher wind power penetrations when simulated DA and 4HA operational wind power forecasts are used (Type A and Type B). When wind power is not considered in the DA and 4HA power plant commitments (Type C) or when it is perfectly forecasted (Type D), the impact of wind power penetration on oil-fired electricity generation is negligible.

Oil-fired electricity generators are characterized by their fast start-up and ramping capabilities. Oil power plants are divided into three categories: oil GT, oil IC, and oil ST. The uncertainty of wind—or, in other words, wind power forecast errors (Type A and Type B)—increases oil-fired electricity generation because of their fast start-up and ramping. Oil GT power plants represent most of the oil-fired electricity generation; oil IC power plants represent the remaining. On the other hand, oil ST power plants are almost never used because of their slower start-up times ramping capabilities and their high variable generation costs. Figure 14 shows the oil-fired generation stack for run Type A, in which wind curtailment is allowed and simulated DA and 4HA operational wind power forecasts are considered.

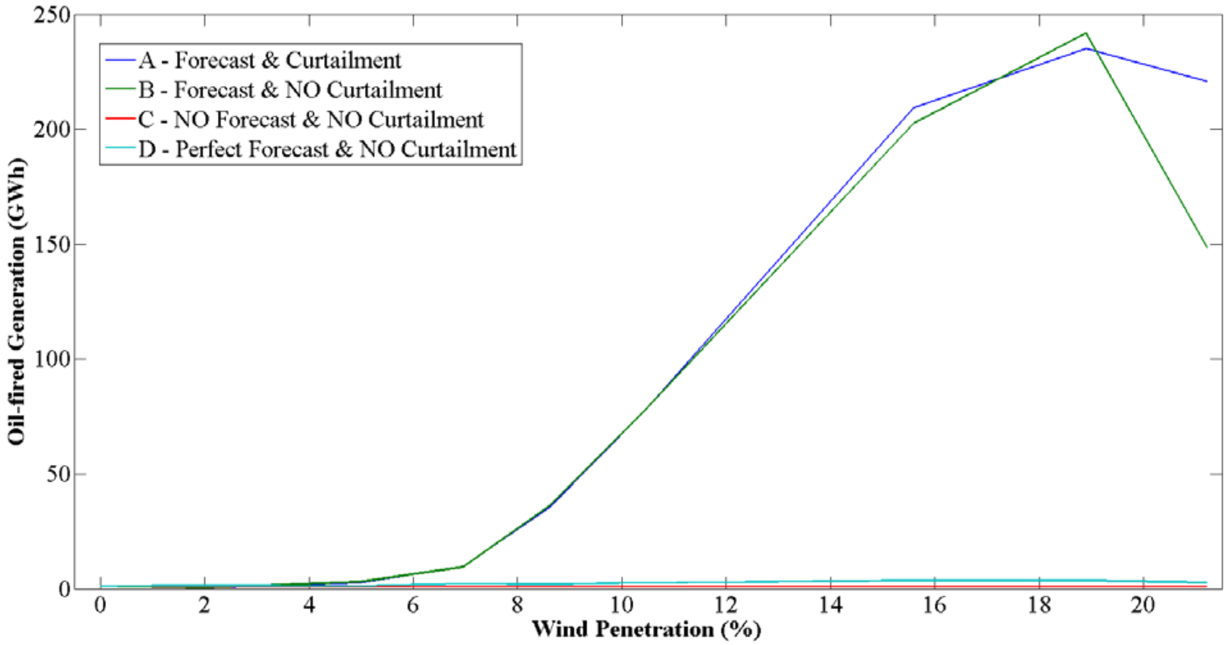

Figure 13. Oil-fired generation

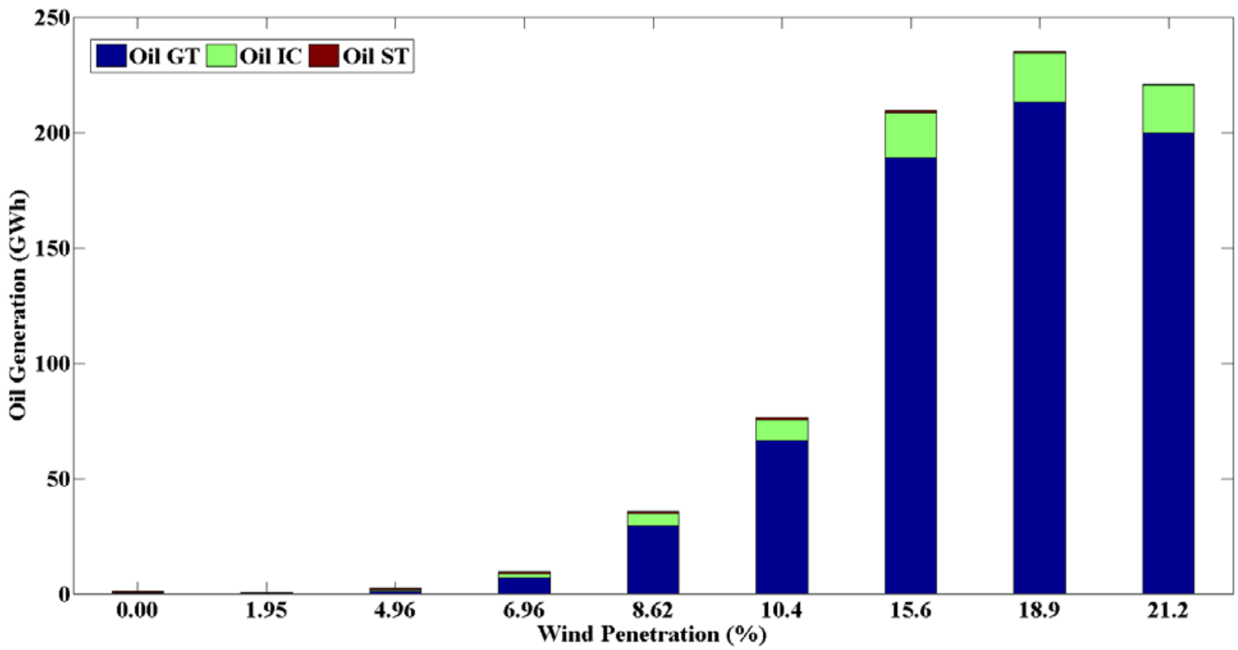

Figure 14. Oil-fired electricity generation mix (SC0 and SC1-A to SC8-A)

4.2 Electricity Exchanges

Electricity exchanges among ISO-NE and its neighboring regions (New Brunswick, Hydro Quebec, and New York Independent System Operator) are modeled in the ISO-NE model as explained in Section 2.4. Figure 15 shows the impact of distributed wind power penetration on electricity exchanges for the four different wind integration modeling approaches.

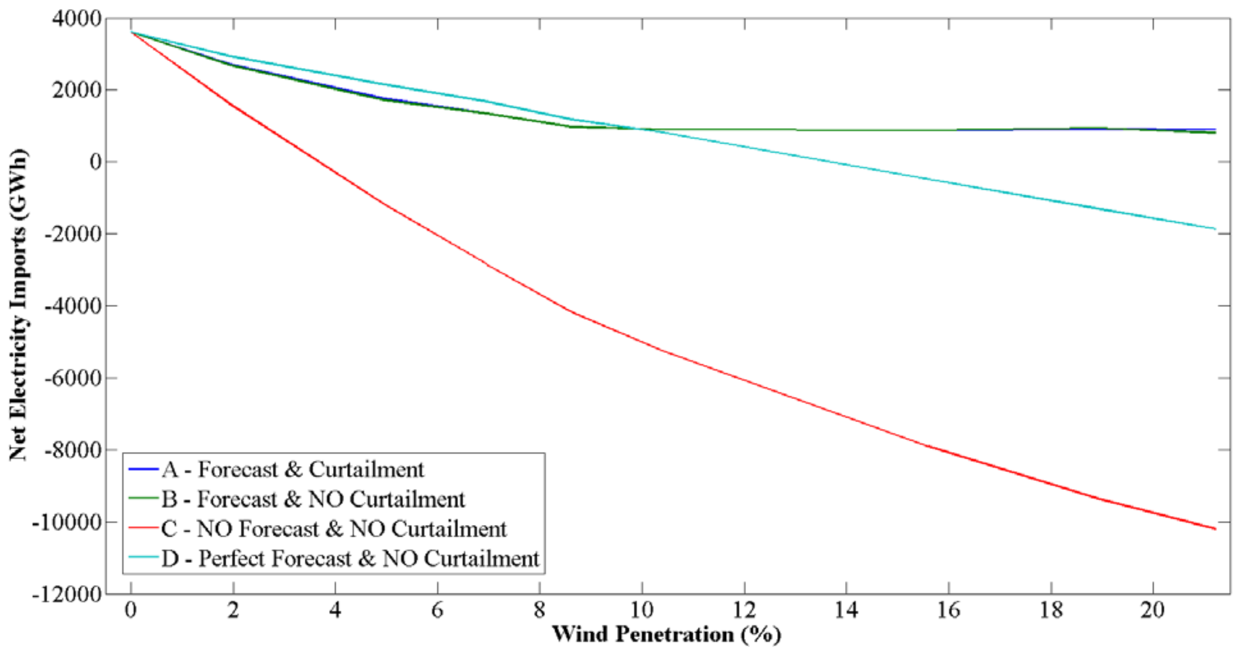

Figure 15. Net electricity imports

In the four cases, ISO-NE's net electricity imports decrease with the increasing share of distributed wind power penetration. The decrease in net electricity imports is explained by the decrease in electricity imports and the increase in electricity exports. The rate of net imports decrease varies significantly among wind integration modeling approaches. For example, if simulated operational wind power forecasts are considered in the DA and 4HA power plant commitments (Type A and Type B), net electricity imports remain positive and almost constant for wind power penetrations higher than 8.62%. If perfect wind power forecasts are used in the DA and 4HA simulations (Type D), net electricity imports decrease at a constant rate for every distributed wind power penetration level. If wind power forecasts are not included in the DA and 4HA simulations (Type C), the impact of distributed wind power penetration on electricity exchanges is much larger, leading to a much higher rate of electricity import decrease. In this case, increasing distributed wind power penetration in the ISO-NE power system reduces electricity imports and increases electricity exports, both to a very large extent. This is the consequence of not considering wind power forecasts in the DA and 4HA simulations and therefore over-committing electricity generation.

In this analysis, the electricity prices in the neighboring regions are assumed to be the same as they were in 2010. Therefore, it has been assumed that nothing varies in the neighboring power systems; whereas wind power penetration increases in the ISO-NE power system. If the neighboring regions were to also increase their wind share in their electricity generation mixes, the electricity prices in the neighboring regions would be lower and the impact of distributed wind (in ISO-NE) on electricity exchanges would be different, especially considering that wind speed in the neighboring regions could be correlated to the wind speed throughout New England at longer timescales.

4.3 Ramping of Electricity Generators

Integrating distributed wind increases the short-term variability and uncertainty in the system and requires faster reactions. Under certain conditions, this need is handled by oil-fired power plants and fast gas generators (GTs and ICs) that increase their annual electricity generation in scenarios with higher wind power penetration. Their fast start-up times and ramping capabilities allow them to react faster to sudden changes caused by the variable and uncertain nature of wind. Other sources of electricity generation that decrease their generation as a result of higher distributed wind power penetration do, however, increase their ramping normalized by their annual electricity generation.

The ramping behavior of the different electricity generation sources varies with wind power penetration level, but it is very similar among the three wind integration modeling approaches that include simulated operational (Type A and Type B) and perfect (Type D) wind power forecasts. Differences are observed with the wind modeling approach that does not include wind power forecasts in the DA and 4HA simulations. Therefore, the following paragraphs compare the upward ramping of the different electricity generation technologies among the wind integration modeling approaches to the simulated operational wind power forecasts (Type B) and the approach without forecasts (Type C). Both approaches do not allow wind power curtailment. Only upward ramping is presented, because downward ramping follows the same patterns. Figure 16 shows the annual upward ramping normalized by the annual electricity generation for different electricity generation sources for the case in which simulated operational wind power forecasts are considered (Type B). Figure 17 shows the same for the case in which wind power is not taken into account in the DA and 4HA power plant commitment decisions (Type C). For both figures, the graph on the right shows a magnified view of lower part of the graph on the left.

As may be expected, the output of hydro pumping plants varies the most. When simulated operational wind power forecasts are considered in the DA and 4HA simulations, their normalized ramping increases for low wind power penetration levels, and it decreases for the highest wind power penetration level compared to the scenario without wind power. On the other hand, if wind power forecasts are not used in the DA and 4HA power plant commitments, the normalized ramping of hydro pumping plants decreases when wind power penetration increases. Nonetheless, the differences between the two modeling approaches and among wind power penetration scenarios are not very large.

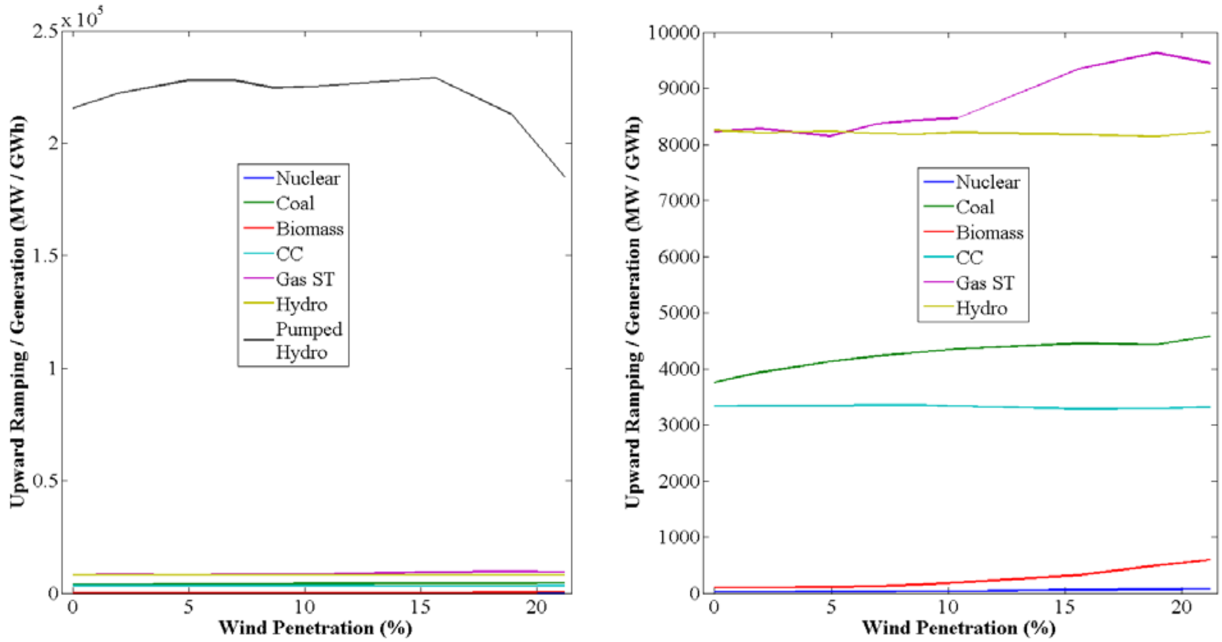

Figure 16. Upward ramping (SC0 and SC1-B to SC8-B)

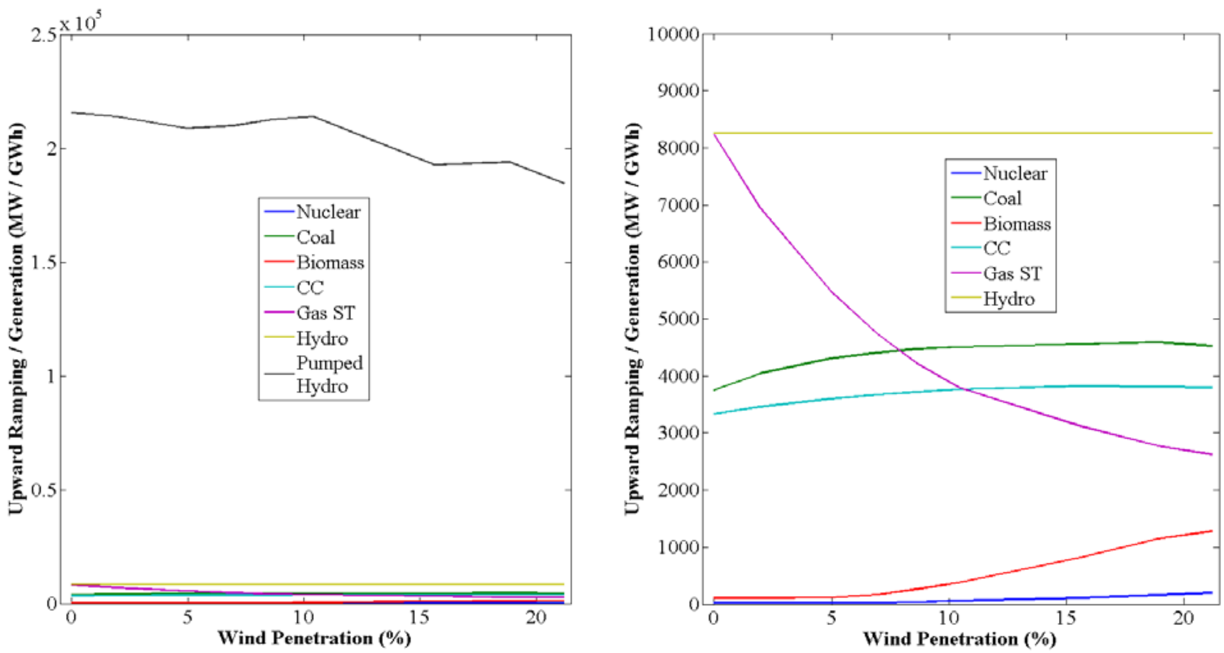

Figure 17. Upward ramping (SCO and SC1-C to SC8-C)

Nuclear and biomass power plants experience the fewest ramping events. Biomass generators do, however, increase their ramping significantly with the presence of variable renewable generation, especially when wind power forecasts are not considered in the DA and 4HA simulations. The ramping of nuclear power plants increases to a much smaller extent with higher distributed wind power penetration, although the ramping of nuclear power plants is still very small compared to that of other technologies given their inflexibility to change their power output because they are designed to meet base load.

Normalized ramping of CC, coal, hydro, and gas ST power plants is much higher than it is for nuclear and biomass power plants. Normalized ramping of CC power plants does not change for different wind power penetrations if wind power forecasts are used. If the latter are not considered in the DA and 4HA simulations, CC power plants increase their normalized ramping as distributed wind increases. The over-commitment of CC power plants as a result of the absence of wind power forecasts increases the ramping of CC power plants. The normalized ramping of coal power plants also increases with higher distributed wind power penetrations, because the wind power forecast errors cause larger and more frequent generators to redispatch in RT. This behavior is observed in all the wind integration modeling approaches.

Normalized ramping of hydropower plants is not affected by wind uncertainty, because hydropower plants are committed and dispatched in the DA simulation. Figure 16 and Figure 17 show that normalized ramping is also not affected by wind variability, because it remains constant for different wind power penetration levels. The small variations in hydro ramping observed in Figure 16 are a consequence of wind power forecasts considered in the DA simulation; Figure 17 shows that hydro ramping is exactly the same in every scenario when wind power forecasts are not considered in the DA simulation.

The largest difference between Figure 16 and Figure 17 is the normalized ramping of gas ST power plants as a function of distributed wind power penetration. When wind power forecasts are used (Figure 16), the normalized ramping of gas ST power plants increases significantly in the highest wind power penetration scenarios. On the other hand, when simulated operational wind power forecasts are not considered in the DA and 4HA simulations (Figure 17), the normalized ramping of gas ST power plants decreases by a large extent: in the highest wind power penetration scenario (SC8-C), it is reduced to a third of what it was in the scenario without wind (SC0). The difference between the two wind integration modeling approaches is not a consequence of wind power forecast errors, because the same pattern as the one shown in Figure 16 is observed for the wind integration modeling approach with perfect wind forecasts (Type D). The difference can be explained by the over-commitment of electricity generation when wind power forecasts are not considered in the DA and 4HA runs. In other words, more generators are online, many of which have better and cheaper ramping capabilities than gas ST power plants.

4.4 Wind Power Curtailment

Wind power curtailment is allowed in only one of the four wind integration modeling approaches: Type A (refer to Table 9). Curtailment of distributed wind is allowed assuming that the power system operator has control of all the individual wind power plants connected to the network. This may not be always the case, considering the large number of distributed wind power plants throughout the network. For example, the 21.2% wind power penetration scenario (SC8) includes 7 GW of wind power distributed throughout 641 individual sites (refer to Table 7). Figure 18 shows wind power curtailment for the different wind power penetration scenarios.

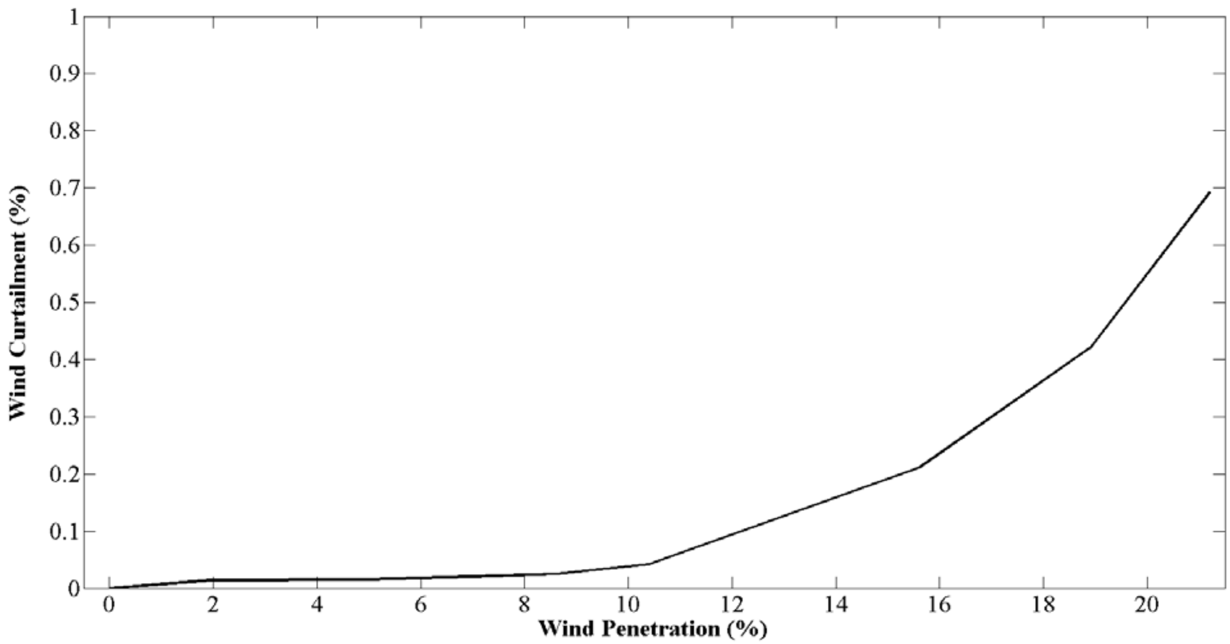

Figure 18. Wind curtailment (SC0 and SC1-A to SC8-A)

Even for the highest wind power penetration scenario (21.2%), wind power curtailment is very low and almost negligible, below 0.7%. However, wind power curtailment increases exponentially as wind power penetration increases. From the shape of the curve shown in Figure 18, it is expected that wind power curtailment would become more significant for wind power penetrations larger than the ones analyzed in this study.

Allowing wind power curtailment is the only difference between run types A and B. (Both wind integration modeling approaches include simulated DA and 4HA operational wind power forecasts.) The results of the two modeling approaches for the eight different wind power penetration scenarios are very similar. The main differences, albeit small, are observed in total generation cost and electricity prices, as discussed in the relevant subsections. For wind power penetrations higher than the ones analyzed in this study, it is expected that larger differences would be observed among runs that model wind curtailment differently (allowed vs. not allowed).

4.5 CO_2 Emissions

Figure 19 shows the annual CO_2 emissions from electricity generation for increasing wind power penetration levels for the four different wind integration modeling approaches. For every wind modeling approach, CO_2 emissions decrease as distributed wind power penetration increases. The rate of decrease of CO_2 emissions is much smaller when wind power forecasts are not considered in the DA and 4HA simulations (Type C). CO_2 emissions do not decrease as much as when DA and 4HA wind power forecasts are considered because of the over-commitment of the fossil-fueled fleet, primarily coal and gas power plants. There is not a significant or relevant difference in CO_2 emissions when perfect wind power forecasts are used in the simulations and compared to the simulated operational forecasts.

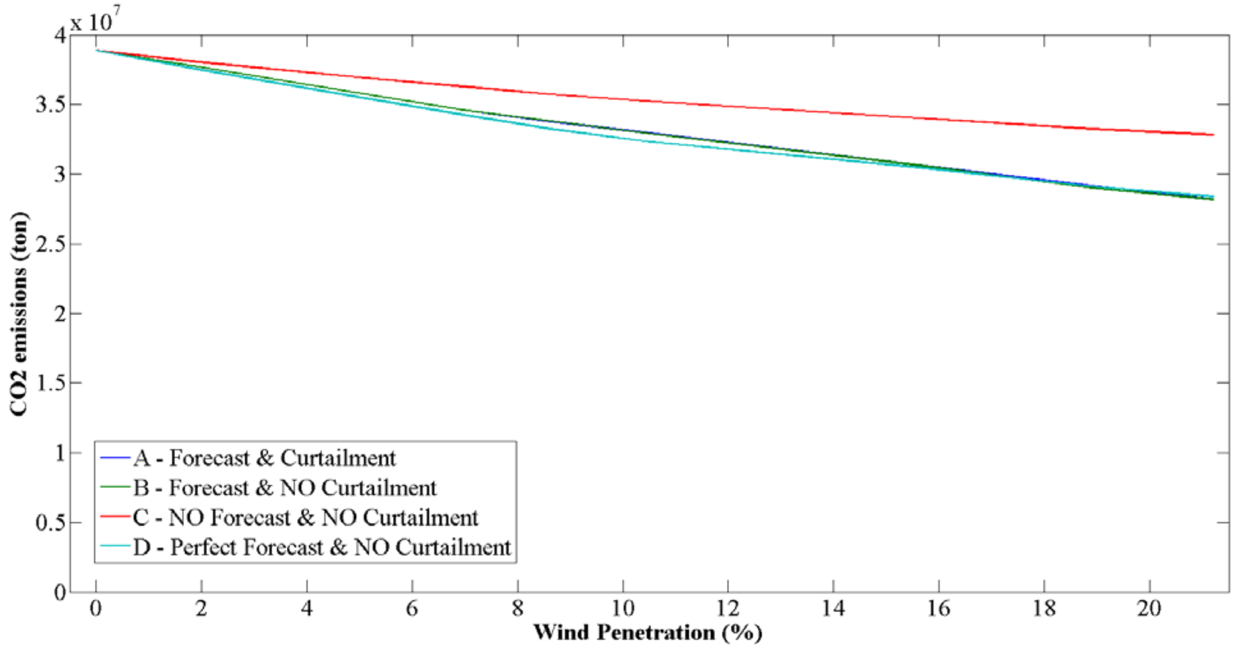

Figure 19. CO_2 emissions

4.6 Electricity Generation Cost

The ISO-NE model calculates the electricity generation cost as the sum of all the variable electricity generation costs of the electricity generators that are connected to the ISO-NE power system. These costs include fuel costs, variable operation and maintenance costs, and start-up and shutdown costs. Figure 21 shows the annual electricity generation cost for the scenario without wind (SC0) and for the increasing wind power penetration scenarios for the four different wind integration modeling approaches. First, for every wind modeling approach, electricity generation cost decreases as wind power penetration increases.

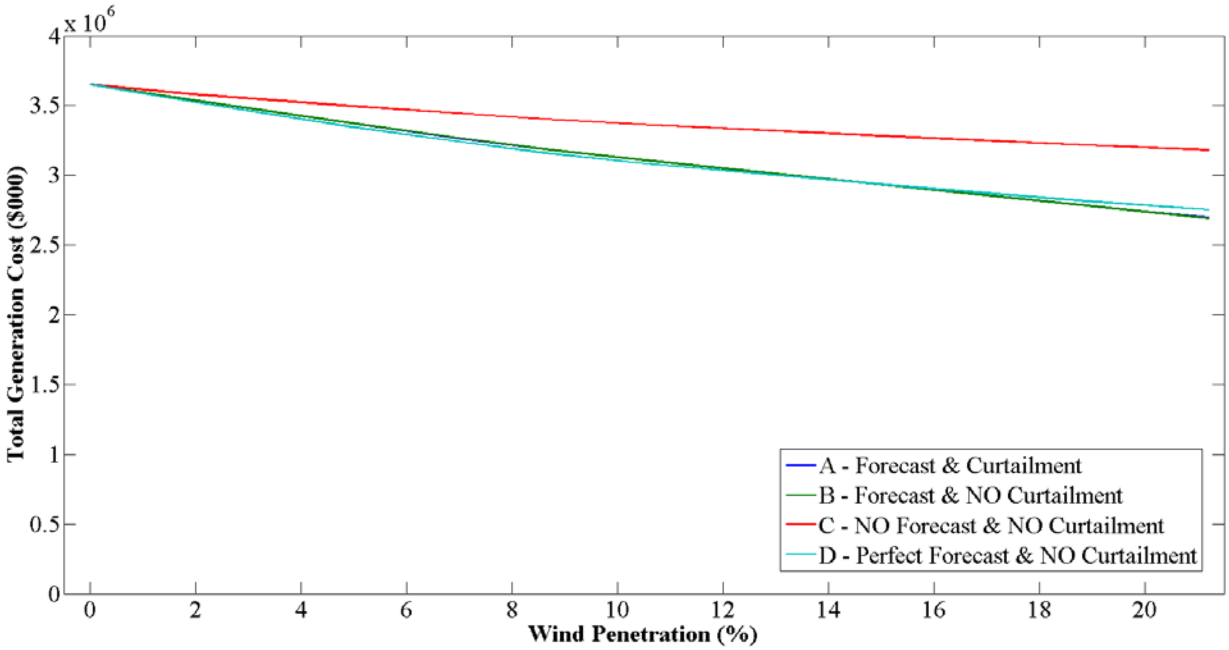

Figure 20. Total electricity generation cost

However, as in the case of CO_2 emissions (see Figure 19), the rate of decrease of electricity generation cost is much smaller when wind power forecasts are not considered in the DA and 4HA simulations (Type C). Electricity generation cost does not decrease as much as when DA and 4HA wind power forecasts are considered because of the over-commitment of the fossil-fuel fleet, primarily coal and gas power plants. There is not a significant or relevant difference in total electricity generation costs when perfect wind power forecasts are used in the simulations and compared to the simulated operational forecasts. However, when perfect wind power forecasts are considered (Type D) or when no wind forecasts are considered (Type C), the impact of increasing wind power penetration is different in electricity exchanges with the neighboring regions when ISO-NE becomes a net electricity exporter in the higher wind power penetration scenarios (see Figure 15). Therefore, the results of electricity generation cost shown in Figure 21 should be analyzed in combination with Figure 15. The differences in electricity generation cost among the four wind integration modeling approaches should take into consideration the net electricity exchanges, because the electricity generation cost is the sum of the costs of generating electricity in ISO-NE and not the variable cost of meeting the electricity demand in ISO-NE. Thus, although it appears that total electricity costs are higher in the perfect forecast case, this does not include the information that ISO-NE becomes a net exporter instead of a net importer.

As discussed in several previous sections, the integration of distributed wind has an impact on the operation of conventional electricity generators. Figure 22 shows the start-up and shutdown costs of conventional power plants for the four different wind integration modeling approaches.

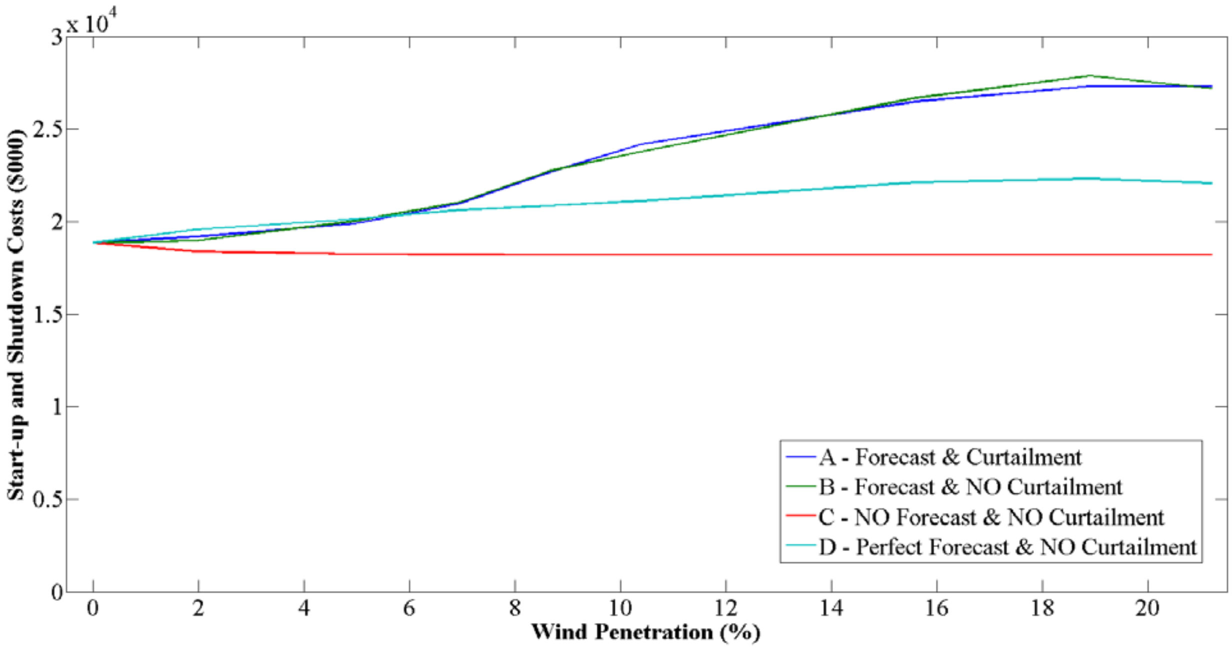

Figure 21. Start-up and shutdown costs

As shown in Figure 22, simulated operational wind power forecast errors (Type A and Type B) increase the number of start-ups and shutdowns of conventional power plants. If wind forecasts are not considered (Type C), wind power penetration does not have an impact on the number of start-ups and shutdowns. If perfect wind power forecasts are used in the DA and 4HA simulations (Type D), the number of start-ups and shutdowns increases with wind power penetration, but with a smaller rate of increase than in the cases that include wind power forecast errors (Type A and Type B).

4.7 Electricity Prices

One of the biggest challenges of integrating variable RES in the electricity system is the impact of electricity generation with zero variable cost on the price of electricity. Figure 23 shows the number of 5-minute time steps in a year during which the mean electricity price in ISO-NE is negative for the scenario without wind and for increasing wind power penetration levels for the four different wind integration modeling approaches.

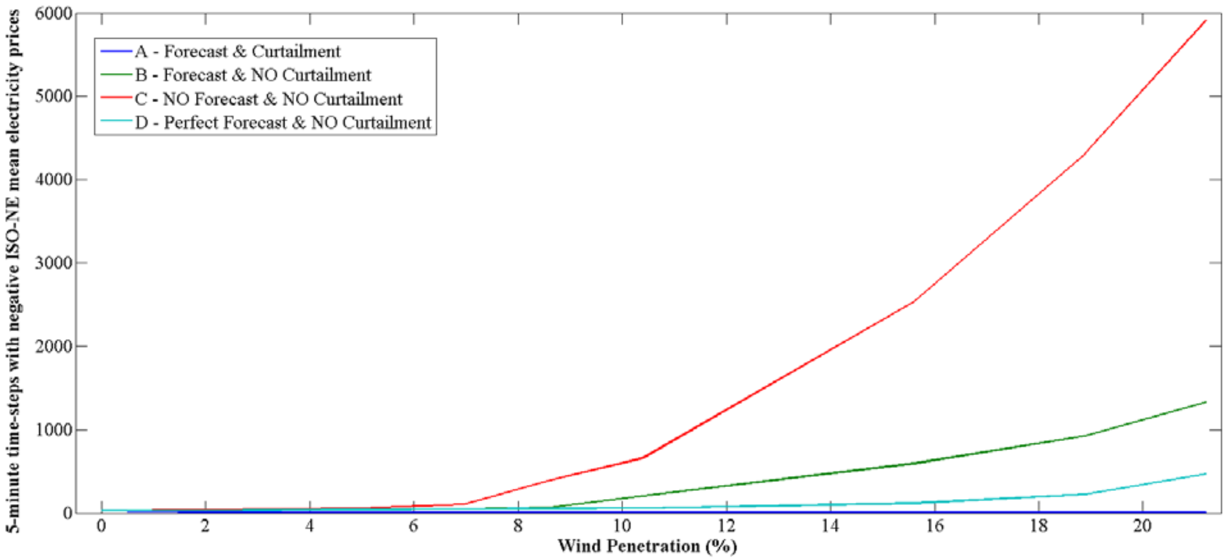

Figure 22. Five-minute time steps with negative ISO-NE mean electricity prices

If wind power curtailment is allowed (Type A), the number of times during which electricity prices are negative remains almost zero for higher wind power penetration levels. In this case, wind power is curtailed during moments when electricity prices would be negative because of the very high wind generation and the subsequent high system operating costs. When wind power curtailment is not allowed (Type B, Type C, and Type D), the number of time steps with negative electricity prices increases for higher wind power penetration levels. The largest number of negative electricity prices is observed when wind power forecasts are not considered in the DA and 4HA simulations because of the over-commitment of conventional power plants.

5 Conclusions and Future Work

The goal of this study was to investigate the impact of distributed wind on transmission-level system operations by simulating the ISO-NE power system using PLEXOS for increasing distributed wind power penetration levels, up to 21%. The analysis was performed by running the ISO-NE model with different wind integration approaches. These differ in allowed wind power curtailment and in wind power forecasts: simulated operational, perfect, and none. The different wind integration modeling approaches allow the impact of distributed wind to be studied for different hypotheses that consider the information and control that the system operator has for the distributed wind connected to the network. They also allow investigating the impact and the value of wind power forecasts in transmission-level system operations.

The integration of distributed wind in ISO-NE impacts the electricity generation mix in several ways. In absolute terms, the two largest changes are observed for gas- and coal-fired electricity generation. Both sources decrease their electricity output with increasing wind power penetration. Wind power forecasts reduce gas-fired electricity generation to a larger extent. If wind power forecasts are not considered, the over-commitment of gas power plants results in higher gas-fired electricity generation. On the other hand, if simulated operational wind power forecasts are used in the DA and 4HA power plant commitments, the resulting generation mix is very similar to the one corresponding to perfect wind power forecasts. The only relevant difference is that the relative reduction in fossil-fueled electricity generation would be more evenly distributed among gas- and coal-fired electricity generators if perfect DA and 4HA wind power forecasts were used: coal-fired electricity generation would be reduced to a larger extent; gas-fired electricity generation would be reduced to a smaller extent. Fuel prices from 2010 were used in this study; if current lower gas prices were used, the results would show higher electricity generation from gas-fired power plants and lower electricity output from coal power plants. Future work may run a sensitivity analysis with different fuel prices, especially looking at different historical ratios of coal and gas prices.

In relative terms, the largest changes in the electricity generation mix caused by distributed wind power penetration correspond to a very large increase in the electricity output of oil-fired GT and gas IC generators when simulated DA and 4HA operational wind power forecasts are used. These power plants are used during few hours in the year and are characterized by their fast start-up and ramping capabilities. The uncertainty of wind increases their electricity output. The same increase is not provided in the absence of forecast errors. If wind power forecasts are not considered, the system experiences a generation over-commitment; if wind power forecasts were perfect, the system would not need to cope with forecast errors that demand additional fast generators' reaction.

The shares of nuclear and hydro in the electricity generation mix are not affected by wind power penetration. They are both committed in the DA market; and in the case of hydro, the ISO-NE model does not allow redispatching in the 4HA and RT simulations. On the other hand, increasing wind power penetration increases hydro pumping and decreases biomass electricity generation.

ISO-NE's net electricity imports decrease with increasing distributed wind power penetration because of a decrease in electricity prices in ISO-NE when wind blows. If perfect wind power forecasts were used, net electricity imports would decrease to a larger extent for the highest wind power penetration scenarios analyzed (compared to the case in which simulated operational wind power forecasts are used), and ISO-NE would be a net electricity exporter. If wind power forecasts were not used, ISO-NE would over-commit generation, it would experience a much larger reduction in net electricity imports, and it would become a net electricity exporter in the scenario with 5% wind power penetration and increase its exports for increasing penetrations. The analysis was performed assuming that the electricity prices in the neighboring regions were the same as they were in 2010; therefore, the analysis assumed that their generation mixes did not vary either. Future work may analyze the impact of integrating distributed wind in ISO-NE while assuming that distributed wind is also integrated in the neighboring regions and therefore assuming different electricity prices than those in 2010.

The integration of distributed wind also has an impact on the ramping of electricity generators (normalized by their electricity output). Hydro pumping power plants vary their output the most; nuclear and biomass power plants experience the fewest ramping events. Biomass generators increase their ramping significantly with increasing distributed wind power penetration. Nuclear power plants, on the other hand, increase their ramping to a much smaller extent because of their inflexibility in changing their power output. The ramping of coal power plants increases with wind power penetration for all wind integration modeling approaches. On the other hand, the ramping of CC power plants increases with wind power penetration only when wind power forecasts are not used, because of the over-commitment of generation. The ramping of gas ST power plants increases with wind power penetration. The opposite is true when wind power forecasts are not used because of the over-commitment of electricity generation, such as CC power plants that have better and cheaper ramping capabilities than gas ST power plants.

From a transmission-level system operator's point of view, wind power curtailment remains very small for the highest wind power penetration scenarios analyzed in this study. The scenario with 21% wind power penetration shows a total wind power curtailment smaller than 0.7%. Nonetheless, the impact of wind power curtailment on electricity prices is more significant. If wind power curtailment is not allowed, the number of 5-minute time steps with negative electricity prices increases for higher wind power penetration levels. The largest number of negative electricity prices is observed when wind power forecasts are not considered because of the over-commitment of electricity generation.

CO_2 emissions decrease as distributed wind power penetration increases. The rate of decrease is smaller when wind power forecasts are not considered because of the over-commitment of electricity generation.

Electricity generation costs decrease as wind power penetration increases. As in the case of CO_2 emissions, the rate of decrease is smaller when wind power forecasts are not considered, even though wind power forecast errors increase start-up and shutdown costs while decreasing fuel costs. There is not a significant difference in electricity generation costs when perfect wind power forecasts are used (compared to the case in which simulated operational wind power forecasts are used). In this case, however, ISO-NE becomes a net electricity exporter for the high wind power penetration scenarios. If revenues from electricity exports were taken into consideration, the net cost difference between state-of-the-art forecasts and perfect forecasts would be larger. Future work may analyze electricity prices in ISO-NE and its neighboring regions in detail and design a methodology to incorporate electricity exchange revenues in the cost analysis of different wind power forecasts.

This study shows that at low penetration levels distributed wind does not have major impacts on transmission-level system operations, even if a system operator does not have any visibility or control of the individual utility-scale wind power plants connected throughout the different distribution networks in ISO-NE. Nonetheless, as distributed wind power penetration increases, the impact on system operations increases as well. At the same time, the values of wind power curtailment and wind power forecasting increase, reducing the impact on transmission-level system operations and decreasing the total system operation costs.

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Appendix A

Table 12 was published by the U.S. Energy Information Administration (2014) and includes the U.S. average levelized cost for power plants entering service in 2018.

Table 10. U.S. Average Levelized Cost (2011 $/MWh) for Power Plants Entering Service in 2018 (EIA 2014)

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (Including Fuel)	Transmission Investment	Total System Levelized Cost
Solar thermal	20	214.2	41.4	0.0	5.9	261.5
Wind—offshore	37	193.4	22.4	0.0	5.7	221.5
Solar PV	25	130.4	9.9	0.0	4.0	144.3
Advanced coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Conventional combustion turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced coal	85	88.4	6.8	30.7	1.2	123.0
Biomass	83	53.2	14.3	42.3	1.2	111.0
Advanced nuclear	90	83.4	11.6	12.3	1.1	108.4
Advanced combustion turbine	30	30.4	2.6	68.2	3.4	104.6
Conventional coal	85	65.7	4.1	29.2	1.2	100.1
Advanced combined cycle with CCS	87	34.0	4.1	54.1	1.2	93.4
Hydro	52	78.1	4.1	6.1	2.0	90.3
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Wind—onshore	**34**	**70.3**	**13.1**	**0.0**	**3.2**	**86.6**
Conventional combined cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced combined cycle	87	17.4	2.0	45.0	1.2	65.6

Figure 26 shows a map of the ISO-NE model in which generators are differentiated by class: nuclear (red), coal (black), gas (blue), oil (purple), hydro (green), and biomass (yellow). If multiple generators are connected to the same node, only one is visible in the map. Nodes with no generators connected to them are represented by grey dots.

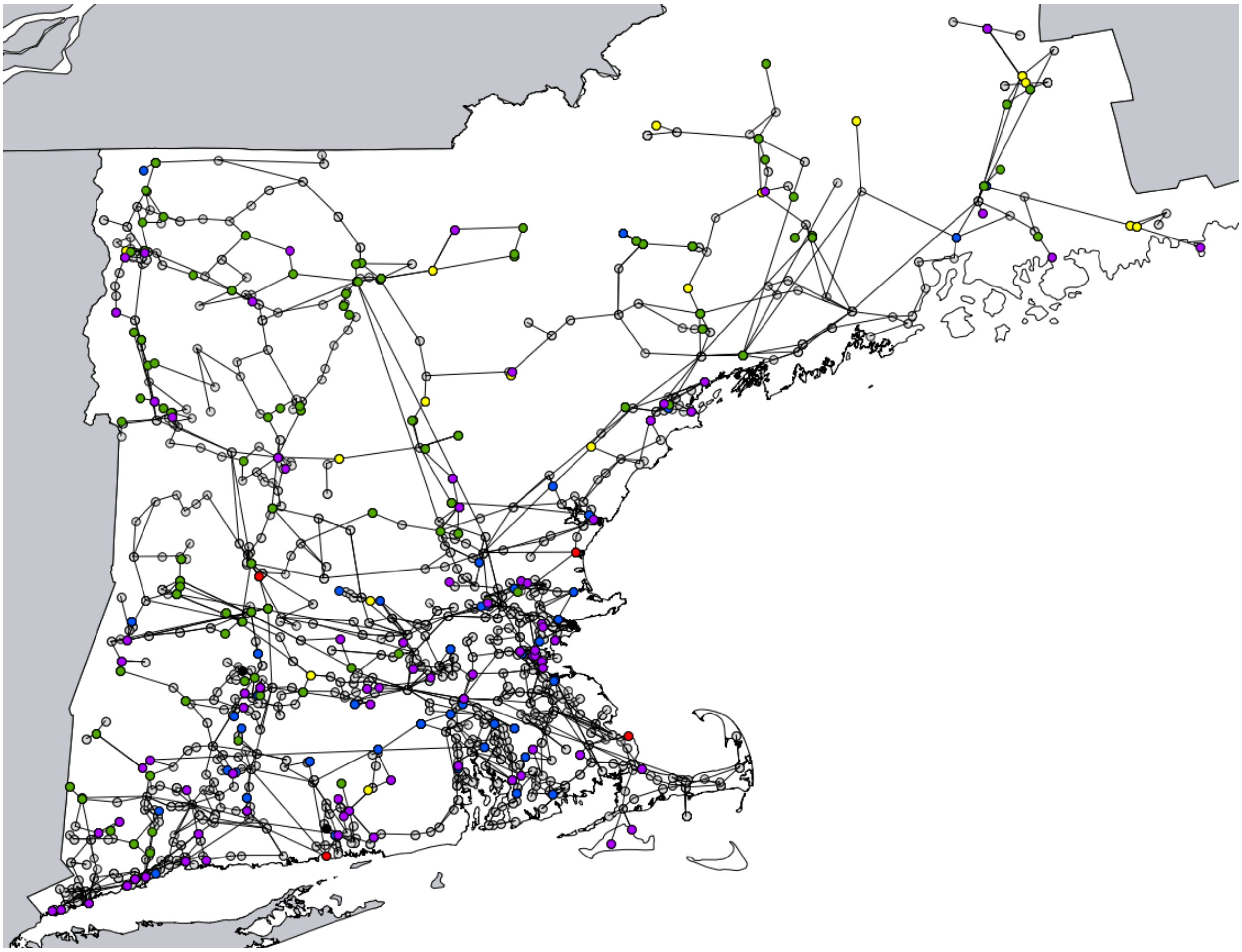

Figure 23. ISO-NE model—generator map

Figure 27 shows a map of the ISO-NE model in which nodes that have load connected to them are differentiated (red dots).

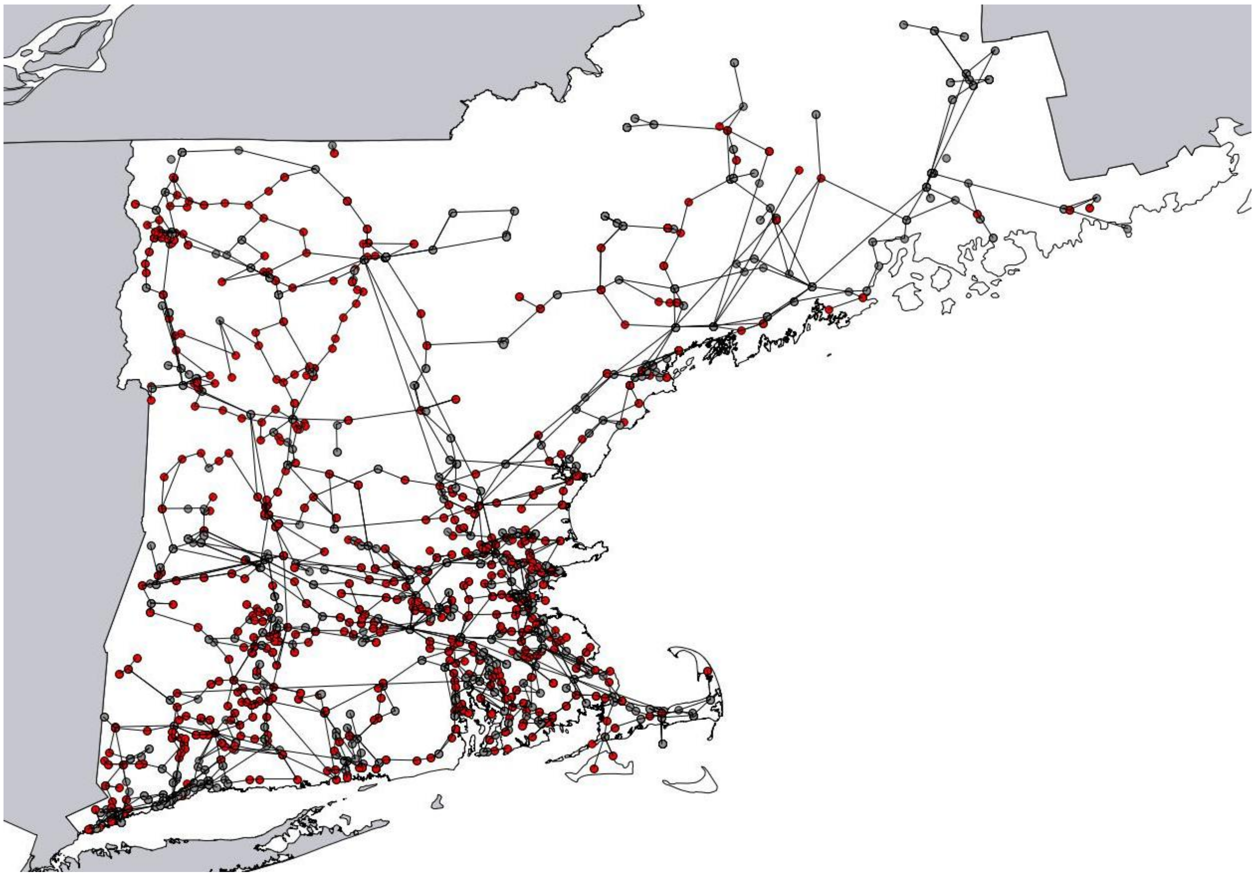

Figure 24. ISO-NE model—nodes with load map

Appendix B

Figure 28 to Figure 35 show maps with the distributed wind site locations for each distributed wind scenario. Red dots represent transmission nodes, and green dots represent wind sites. The black lines among the red dots represent transmission lines.

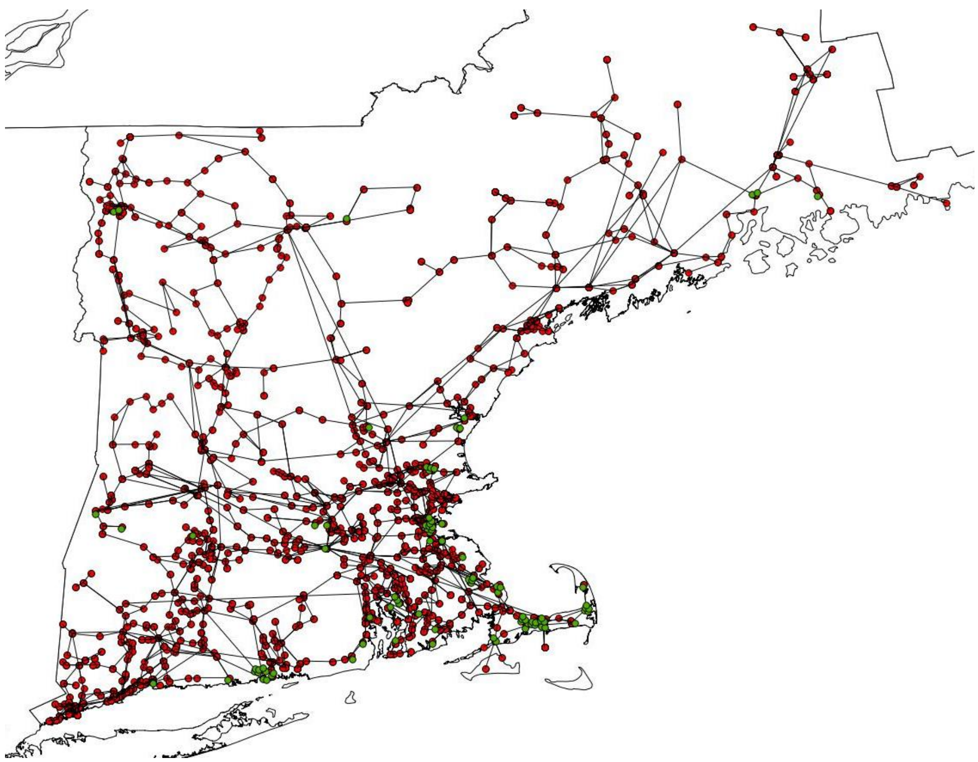

Figure 25. Wind site locations—Scenario 1

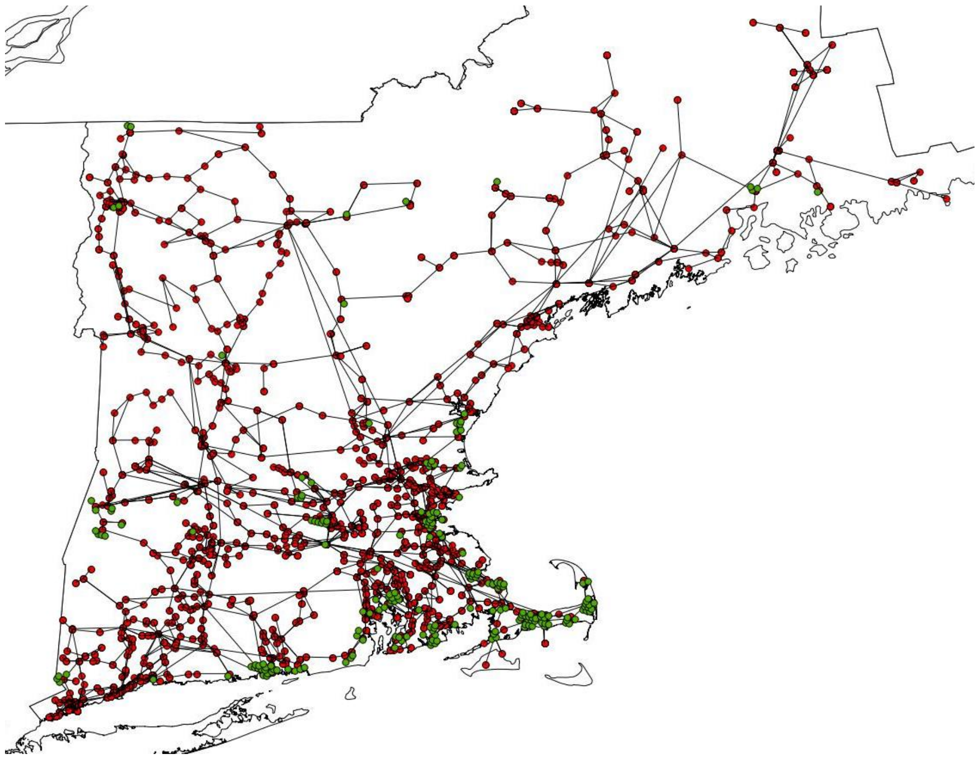

Figure 26. Wind site locations—Scenario 2

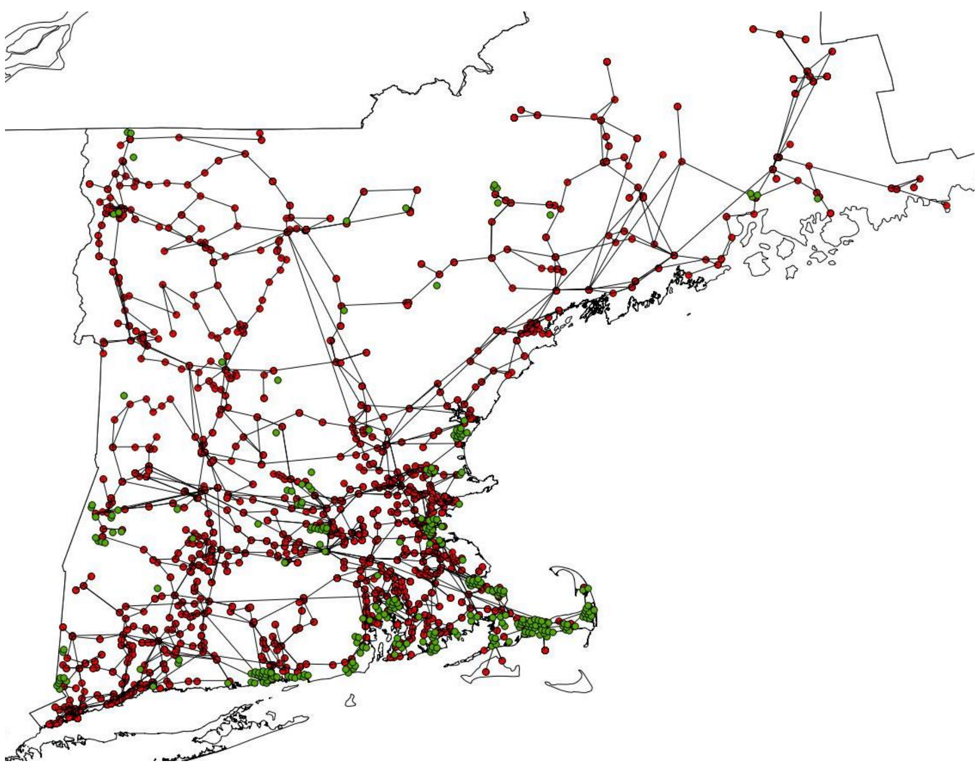

Figure 27. Wind site locations—Scenario 3

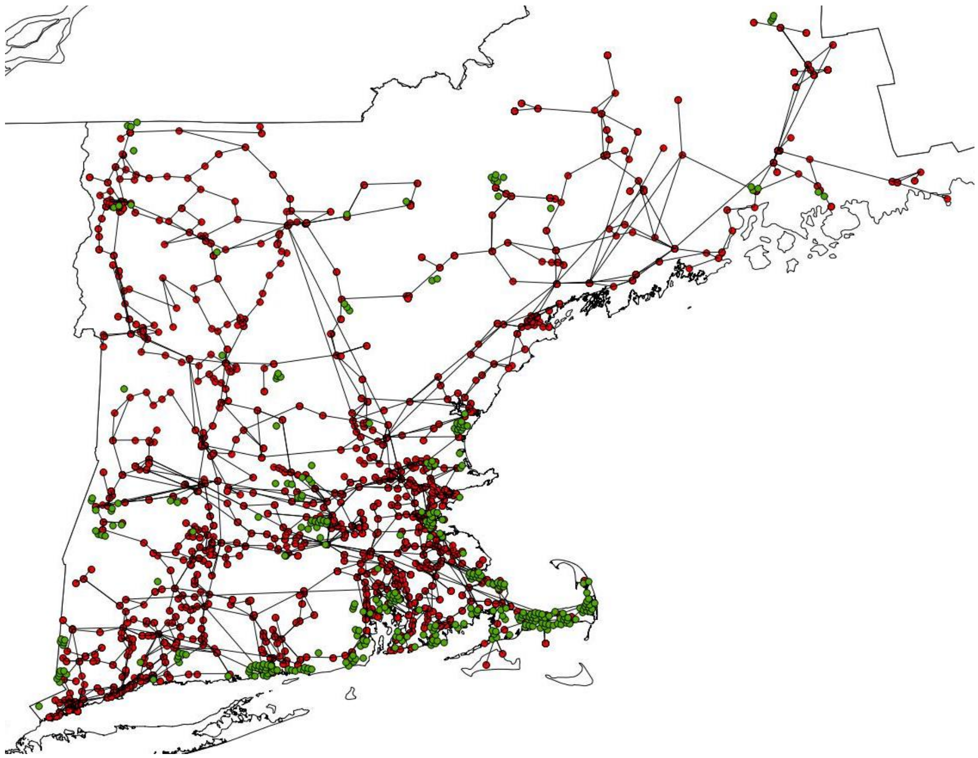

Figure 28. Wind site locations—Scenario 4

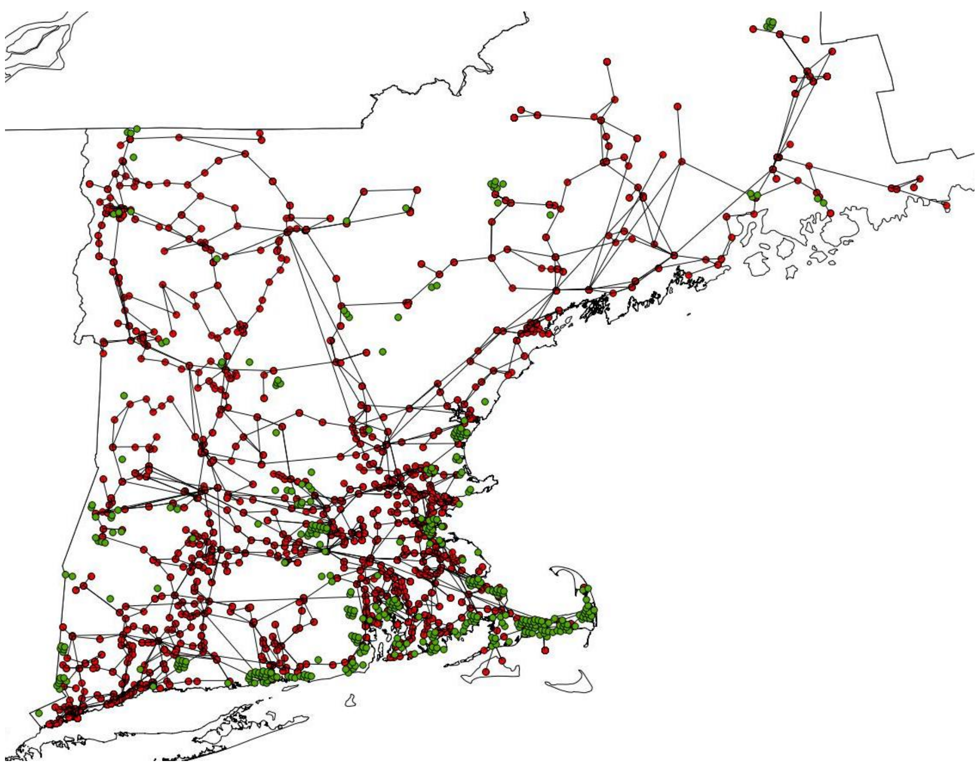

Figure 29. Wind site locations—Scenario 5

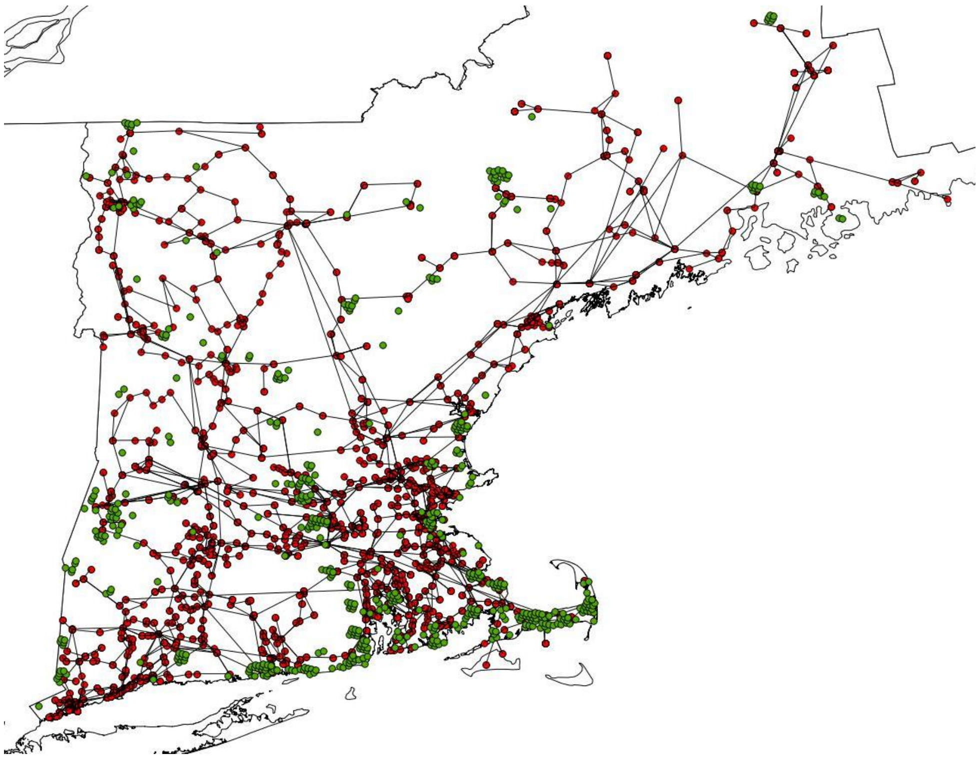

Figure 30. Wind site locations—Scenario 6

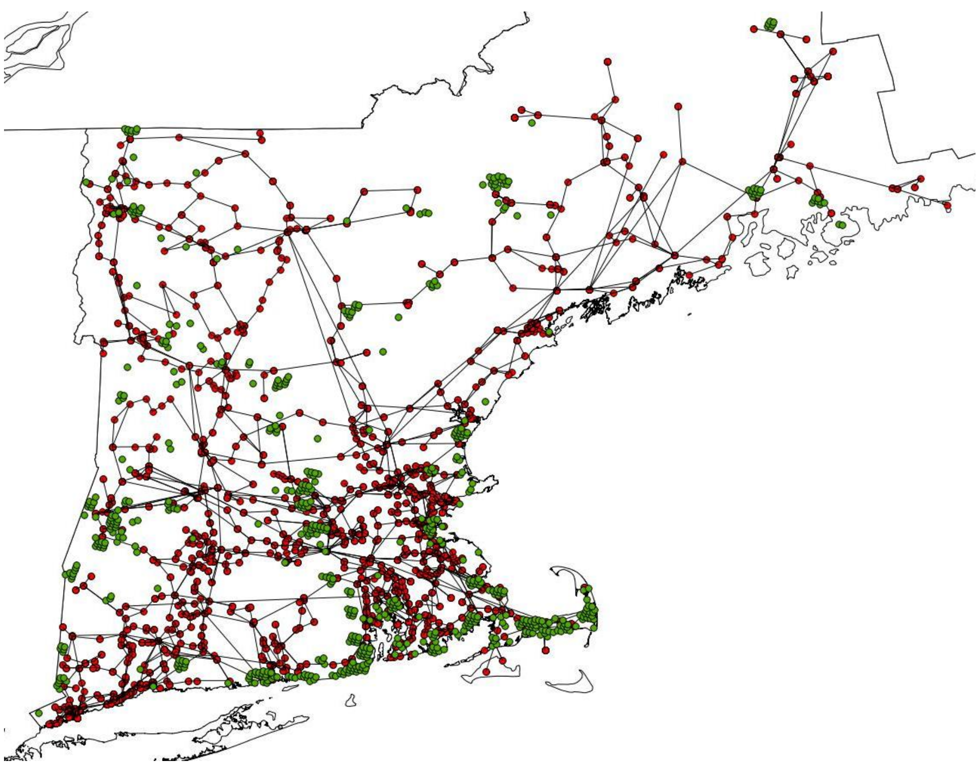

Figure 31. Wind site locations—Scenario 7

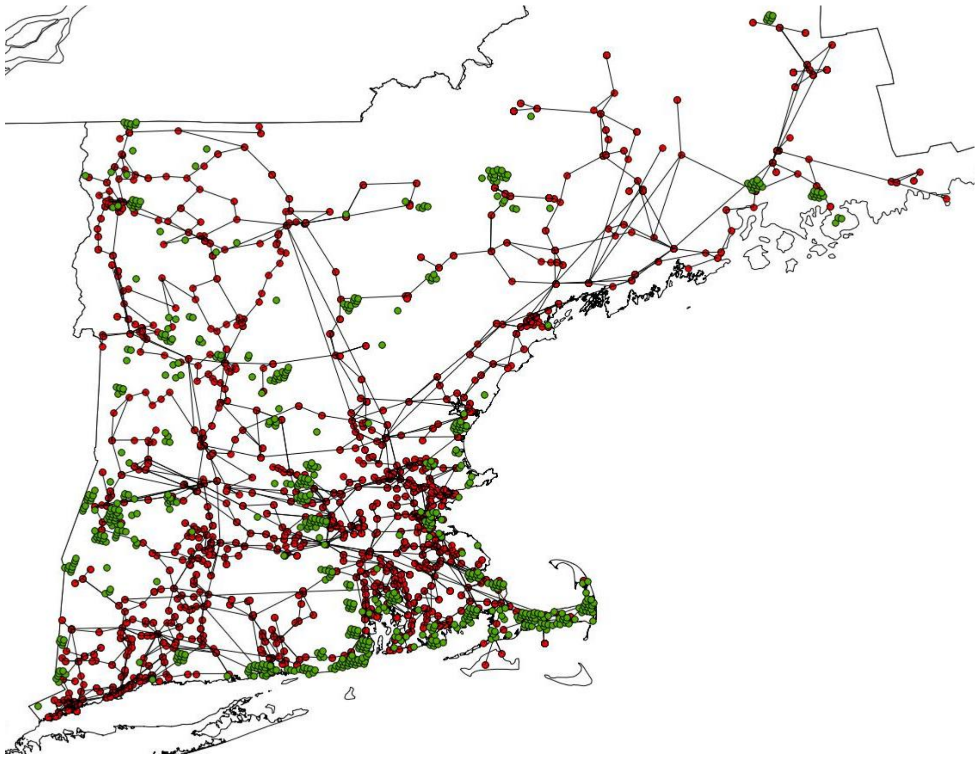

Figure 32. Wind site locations—Scenario 8