GE Energy

Final Report:

New England Wind Integration Study

Prepared for:

ISO New England

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Foreword

This document was prepared by General Electric International, Inc. It is submitted to ISO New England, Inc. Technical and commercial questions and any correspondence concerning this document should be referred to:

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List of Acronyms and Abbreviations

ACE	Area Control Error
ATC	Available Transfer Capability
AWST	AWS Truepower
CC	Combined Cycle
CO2	Carbon Dioxide
CPS1	Control Performance Standard 1
CPS2	Control Performance Standard 2
CT	Combustion Turbine
CT-Oil	Oil Fueled Combustion Turbine
DAM	Day-Ahead Energy Market
EIA	Energy Information Agency
ELCC	Effective Load Carrying Capability
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
GT	Gas Turbine
CT-GAS	Gas Fueled Combustion Turbine
HVDC	High Voltage Direct Current
HQ IMP	Imports of energy from Hydro Quebec
ICR	Installed Capacity Requirement
IMP_EXP	Imports and Exports of Energy out of and into ISO-NE
IPR	Intermittent Power Resources
IVGTF	Integration of Variable Generation Task Force
LAI	Levitan and Associates
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LTE	Long Time Emergency
MAE	Mean Absolute Error
MAPS	Multi Area Production Simulation

MARS	Multi Area Reliability Simulation
Net load	Time synchronous load minus wind generation output
NEWIS	New England Wind Integration Study
NEWRAM	New England Wind Resource Area Model
NLCD	National Land Cover Database
NOx	Nitrogen Oxides
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NUC	Nuclear Fission Fueled Steam Turbine
O&M	Operation and Maintenance
PAC	Planning Advisory Committee
PSH	Pumped Storage Hydro
RSP	Regional System Plan
RTM	Real-Time Energy Market
RTO	Regional Transmission Organization
SIS	System Impact Study
S-o-A	State of the Art
SOx	Sulfur Oxides
St-Coal	Coal Fueled Steam Turbine
St-Gas	Gas Fueled Steam Turbine
St-Oil	Oil Fueled Steam Turbine
St-Other	Cogeneration, Refuse, and Wood fueled generation
TKE	Turbulent Kinetic Energy
TMNSR	Ten Minute Non-Spinning Reserve
TMOR	Thirty Minute Operating Reserve
TMSR	Ten Minute Spinning Reserve
TOR	Total Operating Reserve
TRC	Technical Review Committee
USGS	United States Geological Survey
UWIG	Utility Wind Integration Group

Executive Summary

Introduction

Overview of ISO-NE

ISO New England Inc. (ISO-NE) is the not-for-profit corporation that serves as the Regional Transmission Organization (RTO) and Independent System Operator (ISO) for New England. ISO-NE is responsible for the reliable operation of New England's power generation, demand response, and transmission system; administers the region's wholesale electricity markets; and manages the comprehensive planning of the regional power system. ISO-NE has the responsibility to protect the short-term reliability and plan for the long-term reliability of the Balancing Authority Area, a six-state region that includes approximately 6.5 million businesses and households.

Key Drivers of Wind Power

The large-scale use of wind power is becoming a norm in many parts of the world. The increasing use of wind power is due to the emissions-free electrical energy it can generate; the speed with which wind power plants can be constructed; the generation fuel source diversity it adds to the resource mix; the long-term fuel-cost-certainty it possesses; and, in some instances, the cost-competitiveness of modern utility-scale wind power. Emissions-free generation helps meet environmental goals, such as Renewable Portfolio Standards (RPS)[1] and greenhouse gas control. Once the permitting process is complete, some wind power plants can be constructed in as little as three to six months, which facilitates financing and quick responses to market signals. Wind power, with a fuel cost fixed at essentially zero, can contribute to fuel-cost certainty, and would reduce New England's dependence on natural gas. In New England, the economics of wind power are directly affected by the outlook for the price of natural gas; higher fuel prices generally spur development of alternative energy supplies while lower fuel prices generally slow such development. Wind power development also is directly affected by environmental

[1] Each state in New England has adopted a renewable portfolio standard, except for Vermont, which has set renewable energy goals. RPSs set growing percentage-wise targets for electric energy supplied by retail suppliers to come from renewable energy sources. For a further description of New England related policies potentially affecting wind power see, for example, the ISO-NE Regional System Plan. RSP10 is available at: http://www.iso-ne.com/trans/rsp/index.html.

policy drivers such as restrictions on generator emissions or renewable energy generation targets.

While wind can provide low-priced zero-emissions energy, the variability of wind resources and the uncertainty with which the amount of power produced can be accurately forecasted poses challenges for the reliable operation and planning of the power system. Many favorable sites for wind development are remote from load centers. Development of these distant sites would likely require significant transmission development, which may not appear to be economical in comparison to conventional generation resources (at current prices) and could add complexity to the operations and planning of the system. The geographical diversity of wind power development throughout New England and its neighboring systems in New York and the eastern Canadian provinces would mitigate some of the adverse impacts of wind resource variability if the transmission infrastructure, operating procedures, and market signals were in place to absorb that variability across a larger system. Several Elective and Merchant Transmission Upgrades are in various stages of consideration to access these wind and other renewable resources.

Growth of Wind Power in New England

As of October 2010, approximately 270 megawatts (MW) of utility-scale wind generation are on line in the ISO New England system, of which approximately 240 MW are biddable assets. New England has approximately 3,200 MW of larger-scale wind projects in the ISO Generator Interconnection Queue, more than 1,000 MW of which represent offshore projects and more than 2,100 MW of which represent onshore projects.[2] The wind capacity numbers in the ISO queue are based on nameplate ratings. Figure 0–1 shows a map of planned and active wind projects in New England. As an upper bound of all potential wind resources—and not including the feasibility of siting potential wind projects—New England holds the theoretical potential for developing more than 215 gigawatts (GW) of onshore and offshore wind generation.[3]

[2] The 3,200 MW of wind in the queue is as of October 1, 2010, and includes projects in the affected non-FERC queue.

[3] 2009 Northeast Coordinated System Plan (May 24, 2010); http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html.

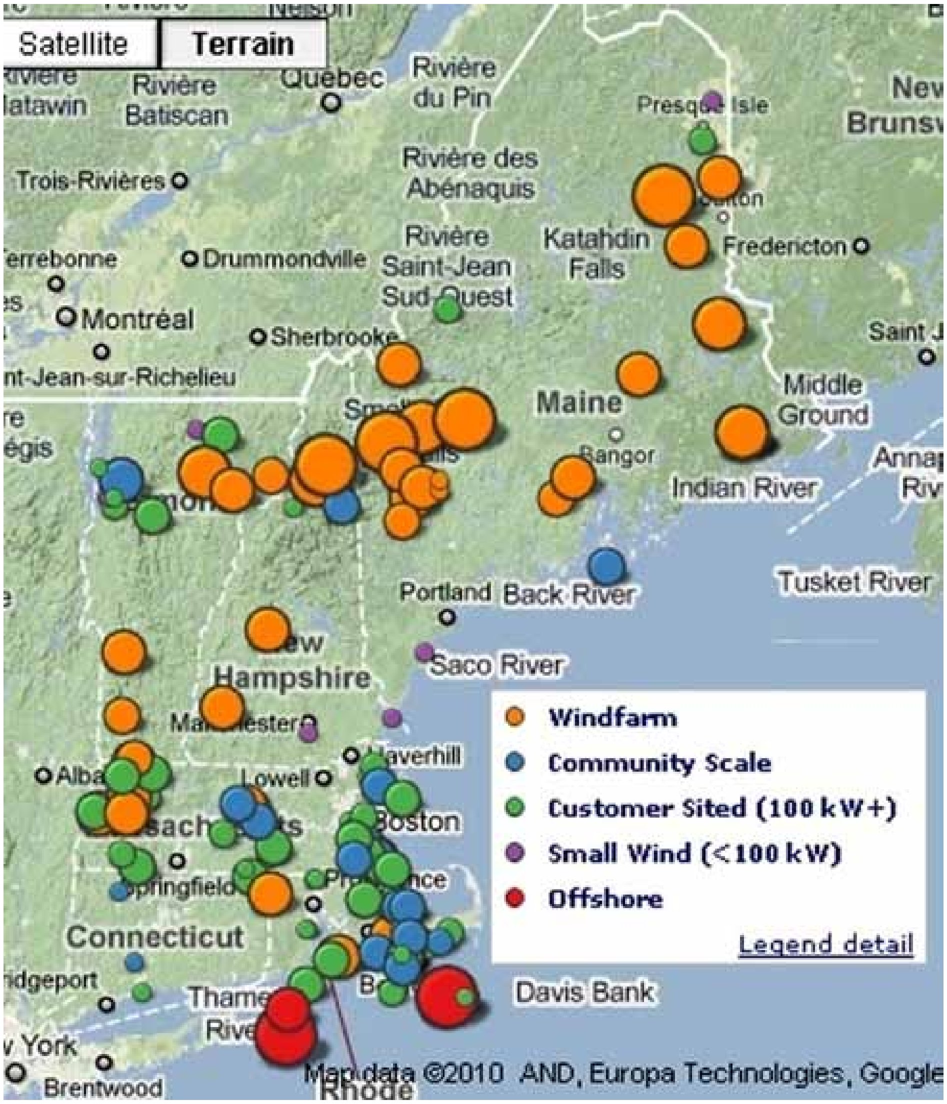

Figure 0–1 Planned and active wind projects in New England, 2010. Source: Sustainable Energy Advantage

The Governor's Economic Study

In 2009, the ISO completed the Scenario Analysis of Renewable Resource Development (the "Governors' Economic Study") – a comprehensive analysis for the integration of renewable resources over a long-term horizon, performed at the request of the Governors of the six New England states.[4] The Governors' Economic Study identified economic and environmental

[4] The Governor's Economic Study is available on the ISO's website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.

impacts for a set of scenario analyses that assumed the development of renewable resources in New England. The study also identified the potential for significant wind power development in the New England states, the effective means to integrate this wind power development into the grid, and related preliminary transmission cost estimates. It did not evaluate operational impacts. Certain scenarios analyzed in the study indicated that, through development in the Northeast, New England and its neighbors could effectively meet the renewable energy goals of the region. Other scenarios showed that the region could be a net exporter of renewable energy.

The Governors' Economic Study ultimately informed the New England Governors' Renewable Energy Blueprint (the "Blueprint"), adopted last year by the six New England state governors.[5] The Blueprint sets forth policy objectives for the development of renewable resources in the Northeast that could ultimately lead to substantial penetration of wind power in New England.

Operational Effects of Large-scale Wind power

Large-scale wind integration adds complexity to power system operations by introducing a potentially large quantity of variable-output resources and the new challenge of forecasting wind power in addition to load.

The power system is designed and operated in a manner to accommodate a given level of uncertainty and variability that comes from the variability of load and the uncertainty associated with the load forecast as well as the uncertainty associated with the outage of different components of the system, such as generation or transmission. Due to a long familiarity with load patterns and the slowly changing nature of those patterns, the variability of the load is quite regular and well understood. The result is that the power system has been planned to ensure that different types of resources are available to respond to the variability of the load (e.g., baseload, intermediate, and fast-start resources have come into service) and the uncertainty associated with the load forecast is generally very small. The uncertainty associated with equipment outages is of a more discrete and "event" type nature that can be handled in a relatively deterministic fashion. This is the basis of contingency analysis where lists of credible contingencies are evaluated on a frequent periodic basis for their effects on power systems operations.

The Governor's Economic Study was conducted pursuant to the Regional System Planning Process established in Attachment K of the ISO OATT.

[5] See Blueprint Materials, available at: http://www.nescoe.com/Blueprint.html.

The combination of wind power's variability and the uncertainty of forecasting wind power make it fundamentally different from analyzing and operating other resources on the system. The weather patterns that drive the generation characteristics for wind power vary across many timescales and are loosely correlated with load. For example, ISO-NE experiences its peak loads during the summer months, while, as observed in this study, wind generation produces more energy during the winter months than in the summer. The uncertainty associated with wind generation is very different from the uncertainty associated with typical dispatchable resources. In general, uncertainty of energy supply from dispatchable conventional generation is due to forced unit outages due to equipment failures or other discrete events. Uncertainty in wind generation is more like uncertainty due to load. The amount of wind generation expected for the next day is forecasted in advance (just as load is forecasted in advance), and the amount of wind generation that actually occurs may be different from the forecasted amount, within the accuracy range of the forecast. In contrast, however, to forecasting of day-ahead load where typical average error is on the order of 1% to 3% Mean Absolute Error (MAE); the accuracy of state-of-the-art day-ahead wind forecasts is in the range of 15% to 20% MAE of installed wind rating. For small amounts of installed wind, load uncertainty dominates, but at higher penetrations of wind, forecast uncertainty becomes very important. In order to plan for the reliable operation of the power system, it is important to study how this combination of variability and associated uncertainty will affect power system operations far enough ahead of time for the effects to be quantified and any required mitigation measures to be put into service.

The loose correlation of wind and load requires the use of a new metric, "net load," to study the impact of large-scale wind generation where the fleet of dispatchable resources is used to balance the time-synchronous variability and uncertainty of the load minus the output of the wind generation. When managing the power system, the output of variable resources such as wind power can be directly subtracted from the amount of load to be served, the dispatchable resources on the system are then used to serve this remaining (i.e., "net") load in order to maintain the power system balance. The net load is then the true variability that must be managed with dispatchable resources and therefore it is the net load that must be studied when determining operational effects.

NEWIS Tasks and Analytical Approach

Anticipating the possible penetration of large-scale wind power in New England, ISO-NE also commissioned this comprehensive wind integration study in 2009 – the New England Wind

Integration Study (the NEWIS) – to assess the operational effects of large-scale wind penetration in New England using statistical and simulation analysis of historical data.[6,7] By focusing on the operational effects of large-scale wind integration, the NEWIS complements and builds on the results of the Governors' Economic Study.

The goals of the NEWIS were to determine the operational, planning and market impacts of integrating substantial wind generation resources for the New England Balancing Authority Area, with due consideration to the neighboring areas, as well as, the measures that may be available to ISO-NE for mitigating any negative impacts while enabling the integration of wind. The NEWIS also sets forth recommendations for implementing these measures. Additionally, the NEWIS identifies the potential operating conditions created or exacerbated by the variability and unpredictability of wind generation resources, and recommends potential corrective activities, recognizing the unique characteristics of the tightly integrated bulk power system in New England and the characteristic of wind generation resources. Consistent with the Governors' Economic Study, the NEWIS examines various scenarios of increasing wind power penetration up to approximately 12 GW of nameplate wind power.

In order to accomplish its goals, the NEWIS captures the unique characteristics of New England's bulk electrical system including load and ramping profiles, geography, system topology, supply and demand-side resource characteristics, and wind profiles and their unique impacts on system operations and planning with increasing wind power penetration. To facilitate the work of the NEWIS, it is broken into five tasks:

Wind Integration Study Survey - involved a review of the experience gained and lessons learned from several previous domestic and international wind integration studies on bulk electric power systems.

Technical Requirements for Interconnection - included the development of specific recommendations for technical requirements for wind generating resources; also investigated and recommended wind power forecasting tools that would be required for system operations as wind penetration increases. This task was completed in fall 2009, with recommendations to

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[6] See NEWIS Materials, New England Wind Integration Study (NEWIS) Wind Scenario and Transmission Overlays, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/newis.pdf.

[7] The core project team included GE Energy Applications and Systems Engineering, EnerNex, and AWS Truepower. Many members of this team have extensive experience and have been among the pioneers of wind integration analysis.

ISO-NE detailed in a report titled "Technical Requirements for Wind Generation Interconnection and Integration"[8].

Mesoscale Wind Forecasting and Wind Plant Models - included development of an accurate and flexible mesoscale hindcasting model for the New England and Maritimes wind resource area (including offshore wind resources) that provides user-specified wind plant output profile data. This tool allows reuse of the mesoscale modeling data for further ISO-NE studies.

Scenario Development and Analysis - developed base case and wind generation scenarios, in consultation with ISO-NE and stakeholders, that included potential and probable scenarios for wind power development up to 24% annual wind energy penetration. This task also included statistical analysis to evaluate the impact of incremental wind generation on the operation of New England's bulk electric power system, focusing on the effects of variability and uncertainty.

Scenario Simulation and Analysis - included production simulations to evaluate the hourly operation of the various scenarios and penetration levels for three calendar years, as well as rigorous reliability calculations using Loss of Load Expectation (LOLE) methods to evaluate the capacity value of the wind generation.

In order to be clear about the interpretation of the methods used, results obtained, and any recommendations provided, it is important to recognize what the NEWIS is and what it is not. The NEWIS is neither a transmission planning study nor a blueprint for wind power development in New England, and large-scale wind power development might or might not occur in the region. The NEWIS takes a snapshot of a hypothetical future year where low, moderate, and large wind power penetrations are assumed. Feedback dynamics in markets, such as the impact of overall reduced fuel use and the changes in fuel use patterns on fuel supply and cost, were not analyzed or accounted for. It is not a goal of ISO-NE to increase the amount of any particular resource; instead the ISO's goal is to provide mechanisms to ensure that it can meet its responsibilities (stated above) for operating the system reliably, managing

[8] See NEWIS Technical Report, available at:
http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf.
ISO-NE presented the recommendations of the NEWIS Technical Report to New England stakeholders at the November 18, 2009 meeting of the Planning Advisory Committee ("PAC"). *These recommendations will be subject to the applicable stakeholder processes prior to implementation.*

transparent and competitive power system markets, and planning for the future needs of the system, while providing a means to facilitate innovation and the fulfillment of New England's policy objectives. In this context, the NEWIS is meant to investigate whether there are any insurmountable operational challenges that would impede ISO-NE's ability to accept large amounts of wind generation.

A fundamental assumption in the NEWIS is that the transmission required to integrate the hypothesized wind generation into the bulk power system would be available and that the wind power resources would interconnect into those bulk transmission facilities. The NEWIS is a system-wide transportation study and, as such, does not account for local issues. For example, even with the limited wind generation that currently exists on the ISO-NE system, there are some instances where local transmission constraints result in curtailment of wind facilities due to the typical development pattern of wind generation facilities in New England and their interconnection under the minimum interconnection standards process. Implementing the recommendations developed as a result of the NEWIS will not solve these issues, unless the aforementioned sizable transmission expansions were to be built and the wind generation facilities were to connect directly into those expansions.

Another important assumption is that the available portfolio of non-wind generation in New England and neighboring systems was held constant across all alternatives considered. Neither attrition nor addition of new non-wind generation was considered as modifications to the base case.

Furthermore, detailed and extensive engineering analysis regarding stability and voltage limits would be required in order to determine the viability of the hypothesized transmission expansions, which in themselves may require substantial effort to site and build. It is also important to note that implementing the recommendations developed during the second task of the NEWIS (e.g., wind power specific grid support functions, wind power forecasting, windplant modeling, and communications and control) is essential for the reliable integration of large-scale wind power into the New England power system.

Finally, in addition to the significant observations mentioned above, changes may be required to systems and procedures within the ISO organization that are yet to be determined. These changes would require additional analysis for increasing levels of wind penetration and for issues identified within New England, or beyond, as system operators gain experience with wind energy. The development, implementation, and operating costs associated with these changes are not accounted for in this study.

Study Scenarios

All of the NEWIS wind scenarios are set to represent approximately the 2020 timeframe. In addition to the base case assumptions, there are five main categories of wind build-out scenarios representing successively greater penetrations of wind. The scenarios are categorized by the aggregate installed nameplate capacity of wind power and the simulated wind fleet's contribution to the region's forecasted annual energy demand. Values used for wind energy generated by each scenario are averages of the three years simulated via mesoscale modeling. Values of annual energy demand for the region and individual states are also averages for the three extrapolated load years used in the simulations and individual load supplied by energy efficiencies that has been bid into the Forward Capacity Market.

These categories of wind build-out scenarios include:

- Partial Queue Build-out
    - Represents 1.14 GW of installed wind capacity
    - Approximately 2.5% of the forecasted annual energy demand
- Full Queue Build-out
    - Represents 4.17 GW of installed wind capacity
    - Approximately 9% of the forecasted annual energy demand
- Medium wind penetration
    - Represents between 6.13 GW and 7.25 GW of installed wind capacity
    - Approximately 14% of the forecasted annual energy demand
- High wind penetration
    - Represents between 8.29 GW and 10.24 GW of installed wind capacity
    - Approximately 20% of the forecasted annual energy demand
- Extra-high wind penetration
    - Represents between 9.7 GW (for offshore) or 12 GW (for onshore) of installed wind capacity
    - Approximately 24% of the forecasted annual energy demand

Of the five categories, the Partial Queue and Full Queue build-outs are comprised of projects that were in the ISO Generator Interconnection Queue as of April 17, 2009, and the queue lists the proposed point of interconnection for each project. All of the build-outs with greater wind penetration consist of wind plants strategically chosen and added to the Full Queue site portfolio, until either the desired aggregate nameplate capacity or the desired energy contribution of the resulting wind fleet was satisfied. A range of wind plant scenarios was developed to represent what the New England system might look like with varying levels of wind penetration, and to represent different spatial patterns of wind development that could occur, including wind development in the Canadian Maritime Provinces. The objective of scenario development was to enable a detailed evaluation of the operational impacts of incremental wind generation variability and uncertainty on New England's bulk electric power system, including the incremental impact contributed by the spatial diversity of wind plants. The NEWIS was not intended to identify real or preferred wind integration scenarios.

In order to represent the impacts of wind portfolio diversity, five layout alternatives were developed for the medium and high wind penetration build-out scenarios, i.e., the 14% energy and 20% energy scenarios, based on sites with the best (highest) capacity factors. Two of these layout alternatives were also used for the extra-high wind penetration build-out scenario. A description of the five layout alternatives developed for each energy target follows:

1. Best Sites Onshore – This alternative includes the onshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative's wind fleet is comprised predominantly of wind plants in northern New England and therefore it exhibits low geographic diversity.

2. Best Sites Offshore – This alternative includes the offshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative features the highest overall capacity factor of each energy/capacity scenario set, but also a low geographic diversity. However, the steadier offshore wind resource features a higher correlation with load than onshore-based alternatives.

3. Balance Case – This alternative is a hybrid of the best onshore and offshore sites, and as such exhibits a high geographic diversity, including a good diversity by state. The offshore component of the wind fleet is divided equally between the states of Massachusetts, Rhode Island, and Maine (this is also the only alternative that includes offshore sites located in Maine).

4. Best Sites by State – This alternative likely represents the most spatially diverse native wind fleet, and is comprised of wind plants exhibiting the highest capacity factor within each state to meet that state's contribution of the desired energy goal. For example, in the 20% energy scenario, each state's wind fleet was built out in an attempt to meet 20% of the state's projected annual energy demand so that the

overall target of 20% of projected annual energy for New England was satisfied. This alternative enables the investigation of the effects of high diversity and wind power development close to New England's load centers. It should be noted that since the Full Queue contained a disproportionately high capacity of wind projects located in Maine, the aggregate energy produced from these plants contributes approximately 58% of this state's forecasted annual energy demand. This meant that the energy contribution of each of the other states was adjusted (percentage-wise) so that the regional wind fleet would produce the overall desired contribution to the forecasted regional energy demand.

5. Best Sites Maritimes – In addition to the Full Queue sites located within New England, this alternative is made up of extra-regional wind plants in the Canadian Maritime Provinces sufficient to satisfy the desired New England region's wind energy or installed capacity. No considerations were made regarding transmission upgrades required to deliver the hypothetical wind power to New England. Wind resources in the Maritimes exhibit a high geographic diversity and an overall capacity factor approaching that of New England's offshore resource. Considering the wind plants in the Full Queue, this alternative features the greatest geographic diversity. Also, given the longitudinal distance of the Maritimes from much of New England, the effects of integrating wind in the presence of time zone shifts could be highlighted.

Wind Data

AWS Truepower (AWST) developed a mesoscale wind model for the NEWIS study area, referred to as the New England Wind Resource Area Model (NEWRAM). The development of NEWRAM is based on the work that AWST conducted as part of the Eastern Wind Integration and Transmission Study (EWITS), for which AWST developed the wind resource and wind power output data. The resulting superset of simulated wind resource data is referred to as NREL's Eastern Wind Dataset and represents approximately 790 GW of potential future wind plant sites within the EWITS study area, and includes almost 39 GW of potential wind resource within the New England region. For the NEWIS, the New England portion of this wind dataset was expanded to include wind resources in the Canadian Maritimes and additional siting screens and validation analyses were applied. This NEWRAM dataset, which includes wind plant power output profiles as well as day-ahead wind forecasts for the calendar years of 2004, 2005, and 2006, provided the raw material necessary to build the various wind scenarios for the NEWIS.

Load Data

The load data used in the hourly production cost simulation analysis portion of the NEWIS comes from the ISO-NE pricing nodes (aka. p-nodes). P-nodes represent locations on the transmission system where generators inject power into the system or where loads withdraw power from the system. For the NEWIS, the load data from p-nodes has been aggregated into the respective Regional System Plan subareas. Historical data was extracted for years 2004, 2005, and 2006.

One-minute average total ISO New England load data was derived from the Plant Information (PI) data historian, which extracts data from the Energy Management System used for power system control.

Transmission Expansions

The NEWIS used a base-case transmission configuration for the 2019 ISO-NE system, as well as three transmission overlays developed as part of the previously described 2009 Governors' Study:

- 2019 ISO-NE System ("existing") – used for base case.[9]
- Governors' 2 GW Overlay – used as developed for Governor's Study.
- Governors' 4 GW Overlay/1,500 MW New Brunswick Interchange – An additional 345 kV line taken from the Governors' 8 GW Overlay was included for Southeastern Massachusetts in this overlay.
- Governors' 8 GW Overlay/1,500 MW New Brunswick Interchange

Due to scope constraints, only thermal limits were developed, investigated, and utilized for the NEWIS study. Voltage and stability limits would very likely reduce assumed transfer capability so the transfer capabilities of the hypothesized transmission expansion assumed in the study should be considered an upper bound.

Analytical Methods

The primary objective of this study was to identify and quantify system performance or operational problems with respect to load following, regulation, operating reserves, operation

[9] The base-case system for 2019 assumes completion of transmission projects in the 2009 RSP.

during low-load periods, etc. Three primary analytical methods were used to meet this objective: statistical analysis, hourly production simulation analysis, and reliability analysis. While the NEWIS tested the feasibility of wind integration under hypothetical future scenario analyses developed for the study, real world operating and system performance conditions can vary significantly from these types of hypothesized scenarios.

Statistical analysis was used to quantify variability due to system load, as well as wind generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The power grid already has significant variability due to periodic and random changes to system load. Wind generation adds to that variability, and increases what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind generation for each scenario. The statistical analysis also characterized the forecast errors for wind generation.

Production simulation analysis with General Electric's Multi-Area Production Simulation software (GE MAPS) was used to evaluate hour-by-hour grid operation of each scenario for three years with different wind and load profiles. The production simulation results quantified numerous impacts on grid operation including the primary targets of investigation:

- Amount of maneuverable generation on-line during a given hour, including its available ramp-up and ramp-down capability to deal with grid variability due to load and wind
- Effects of day-ahead wind forecast alternatives in unit commitment
- Changes in dispatch of conventional generation resources due to the addition of new renewable generation
- Changes in transmission path loadings

Other measures of system performance were also quantified, including:

- Changes in emissions (NOx, SOx, CO2) due to renewable generation
- Changes in energy costs and revenues associated with grid operation, and changes in net cost of energy
- Changes in use and economic value of energy storage resources

Reliability analysis involved loss of load expectation (LOLE) calculations for ISO-NE system using General Electric's Multi-Area Reliability Simulation program (GE MARS). The analysis quantified the impact of wind generation on overall reliability measures, as well as the capacity values of the wind resources. ISO-NE's current method of determining the capacity value of wind plants was also compared with the LOLE/ELCC method. [10]

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics and production simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind generation into the ISO-NE power grid.

Key Findings and Recommendations

The study results show that New England could potentially integrate wind resources to meet up to 24% of the region's total annual electric energy needs in 2020 if the system includes transmission upgrades comparable to the configurations identified in the Governors' Study. It is important to note that this study assumes (1) the continued availability of existing supply-side and demand-side resources as cleared through the second FCA (in other words, no significant retirements relative to the capacity cleared through the second FCA), (2) the retention of the additional resources cleared in the second Forward Capacity Auction, and (3) increases in regulation and operating reserves as recommended in this study.

Figure 0–2 shows the annual energy from the ISO-NE generation fleet with increasing levels of wind generation for the NEWIS study of the horizon year 2020. The pie charts are for the best sites onshore layout, but since energy targets are the same for all layout alternatives within each scenario, the results presented in the pie charts are very similar across the range of layout alternatives within each scenario.

[10] Loss of load expectation (LOLE) is the expected number of hours or days that the load will not be met over a defined time period. Effective Load Carrying Capability (ELCC) is a data driven metric for capacity value, and represents the amount of additional load that can be served by the addition of a generator while maintaining the existing level of reliability.

The existing ISO-NE generation fleet is dominated by natural-gas-fired resources, which are potentially very flexible in terms of ramping and maneuvering. As shown in the upper left pie chart of Figure 0–2 natural gas resources provide about 50% of total annual electric energy in New England assuming no wind generation on the system. Wind generation would primarily displace natural-gas-fired generation since gas-fired generation is most often on the margin in the ISO-NE market. The pie charts show that as the penetration of wind generation increases, energy from natural gas resources is reduced while energy from other resources remains relatively constant. At a 24% wind energy penetration, natural gas resources would still be called upon to provide more than 25% of the total annual energy (lower right pie chart). In effect, a 24% wind energy scenario would likely result in wind and natural-gas-fired generation providing approximately the same amount of energy to the system, which would represent a major shift in the fuel mix for the region. It is unclear, given the large decrease in energy market revenues for natural-gas-fired resources, whether these units would be viable and therefore continue to be available to supply the system needs under this scenario.

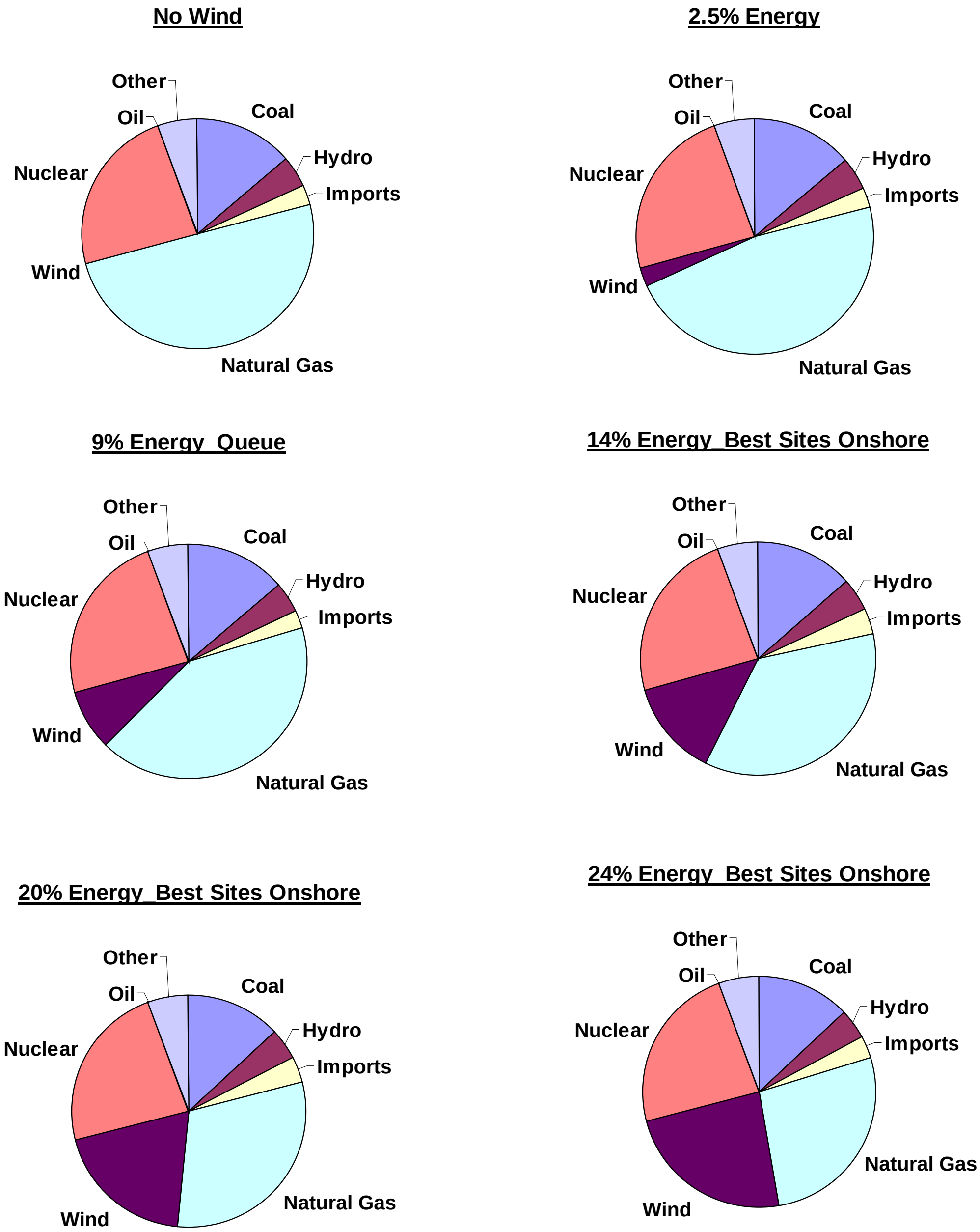

Figure 0–2 Annual Energy from ISO-NE Generation Fleet with Increasing Wind Energy Penetration.

The remainder of this chapter is organized as follows: The section on Statistical Analysis through the section covering Capacity Value of Wind Generation summarize key analytical results related to statistical characterization of the scenarios, regulation and operating reserves, impacts on hourly operations, and capacity value of wind generation. The High-Level Comparison of Scenario Layouts section presents a high-level comparison of the study scenarios. The Recommended Changes to ISO-NE Operating Rules and Practices section presents recommended changes to ISO-NE operating rules and practices related to the following issues:

- Capacity Value
- Regulation
- Reserves
- Wind Forecasting
- Maintaining System Flexibility
- Wind Generation and Dispatch
- Saving and Analyzing Operating Data

The Other Observations from Study Results section summarizes other significant observations from the study results, including:

- Flexible Generation
- Energy Storage
- Dynamic Scheduling
- Load and Wind Forecasting with Distributed Wind Generation

The Technical Requirements for Interconnection of Wind Generation section relates recommendations and observations in this report back to the technical requirements for interconnection of wind plants in the previously published Task 2 report. The Future Work section includes recommendations for future work.

Statistical Analysis

The observations and conclusions here are made on the basis of three years of synthesized meteorological and wind production data corresponding to calendar years 2004, 2005, and 2006. Historical load data for those same calendar years were scaled up to account for anticipated load growth through year 2020.

The wind generation scenarios defined for this study show that the winter season in New England is where the highest wind energy production can be expected. As is the case in many other parts of the United States, the higher load season of summer is the “off-season” for wind generation.

While New England may benefit from an increase in electric energy provided by wind generation primarily during the winter period, the region will still need to have adequate capacity to serve summer peak demand. Given current operating practices and market structures, the potential displacement of electric energy provided by existing resources raises some concern for maintaining adequate capacity (essential for resource adequacy) and a flexible generation fleet (essential to balance the variability of wind generation).

The capacity factors for all scenarios follow the same general trend. Seasonal capacity factors above 45% in winter are observed for several of the scenarios. In summer, capacity factors drop to less than 30%, except for those scenarios that contain a significant share of offshore wind resources.

Based on averages over the entire dataset, seasonal daily patterns in both winter and summer exhibit some diurnal (daily) behavior. Winter wind production shows two daily maxima, one in the early morning after sunrise, and the other in late afternoon to early evening. Summer patterns contain a drop during the nighttime hours prior to sunrise, then an increase in production through the morning hours. It is enticing to think that such patterns could assist operationally with morning load pickup and peak energy demand, but the patterns described here are averages of many days. The likelihood of any specific day ascribing to the long-term average pattern is small.

The net load average patterns by season reveal only subtle changes from the average load shape. No significant operational issues can be detected from these average patterns. At the extremes, the minimum hourly net load over the data set is influenced substantially. In one of the 20% energy scenario layouts, the minimum net load drops from just about 10 GW for load alone to just over 3 GW. Impacts of these low net load periods were assessed with the production simulation analysis.

The day-ahead wind power forecasts developed for each scenario show an overall forecast accuracy of 15% to 20% Mean Absolute Error (MAE). This is consistent with what is considered the state of the commercial art. These forecast errors represent the major source of uncertainty attributable to wind generation. The impacts of forecast errors on hourly operations were evaluated in the production simulation analysis.

Shorter-term wind power forecasts are also valuable for system operations. This study addressed the use of persistence forecasts over the hour-ahead and ten-minute-ahead time periods. A persistence forecast assumes that future generation output will be the same as current conditions. For slowly changing conditions, short-term persistence forecasts are currently about as accurate statistically as those that are skill-based, but this relationship breaks down as hour-to-hour wind variability increases. Operationally significant changes in wind generation over short periods of time, from minutes to hours (known as ramping events), highlight this issue. As a first estimate, operationally significant ramps are often considered to be a 20 percent change in power production within 60 minutes or less. However, the actual percent change that is operationally significant varies depending on the characteristics of the power grid and its resources. As the rate and magnitude of a ramp increases, persistence forecasts tend to become less and less accurate for the prediction of short-term wind generation.

While the persistence assumption works for a study like this one, in reality ISO-NE will need better ramp-forecasting tools as wind penetration increases. Such tools would give operators the means to prepare for volatile periods by allocating additional reserves or making other system adjustments. There has been recent progress in this area and better ramp forecasting tools are now being developed. For example, AWS Truepower recently deployed a system for the Electric Reliability Council of Texas (ERCOT) known as the ERCOT Large Ramp Alert System (ELRAS), which provides probabilistic and deterministic ramp event forecast information through a customized web-based interface. ELRAS uses a weather prediction model running in a rapid update cycle, ramp regime-based advanced statistical techniques, and meteorological feature tracking software to predict a range of possible wind ramp scenarios over the next nine hours. It is highly recommended that ISO-NE pursue the development of a similar system tailored to forecast the types of ramps that may impact New England.

Regulation and Operating Reserves

Statistical analysis of load and wind generation profiles as well as ISO-NE operating records of Area Control Error (ACE) performance were used to quantify the impact of increasing penetration of wind generation on regulation and operating reserve requirements.[11]

All differences between the scenarios stem from the different variability characteristics extracted from three years of mesoscale wind production data in the NEWRAM. The methodology and ISO-NE load are the same for each scenario, so wind variability is the only source of differences between scenarios.

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[11] ACE is a measurement of the instantaneous difference between the net actual and scheduled electric energy flows over the interchange between two regions. It is used to evaluate system control performance in real-time operating conditions. The ISO uses the ACE to dispatch resources that can provide regulation service to the electric grid.

Regulation

Significant penetration of wind generation will increase the regulation capacity requirement and will increase the frequency of utilization of these resources. The study identified a need for an increase in the regulation requirement even in the lowest wind penetration scenario (2.5% wind energy), and the requirement would have noticeable increases for higher penetration levels. For example, the average regulation requirement for the load only (i.e., no wind) case was 82 MW. This requirement increases to 161 MW in the 9% wind energy scenario—and to as high as 313 MW in the 20% scenario.

The primary driver for increased regulation requirements due to wind power is the error in short-term wind power forecasting. The economic dispatch process is not equipped to adjust fast enough for the errors inherent in short-term wind forecasting and this error must be balanced by regulating resources. (This error must be accounted for in addition to the load forecasting error.)

Figure 0–3 shows regulation-duration curves for increasing levels of wind penetration. It shows the number of hours per year where regulation needs to be equal to or greater than a given value. For example, the dark blue curve (the left-most curve) shows that between 30 MW and 190 MW of regulation are required for load alone. The 2.5% Partial Queue scenario (the light blue line to the right of the load-only curve) increases the regulation requirement to a range of approximately 40 MW to 210 MW; the overall shape tracks that of the load-only regulation requirement curve. In the higher wind penetration scenarios, this minimum amount of required regulation capacity increases and the average amount of regulation required increases such that the shapes of the curves no longer track that of the load-only curve—this is indicative that the increased regulation capacity will likely be required to be utilized more frequently. The purple curve (the middle curve) shows that a range of approximately 50 MW to 270 MW of regulation is required with 9% wind energy penetration. The yellow and red curves (to the right of the 9% wind penetration curve just discussed) show that the required regulation increases to ranges of approximately 75 MW to 345 MW and approximately 80 MW to 430 MW, respectively. These estimates are based on rigorous statistical analysis of wind and load variability.

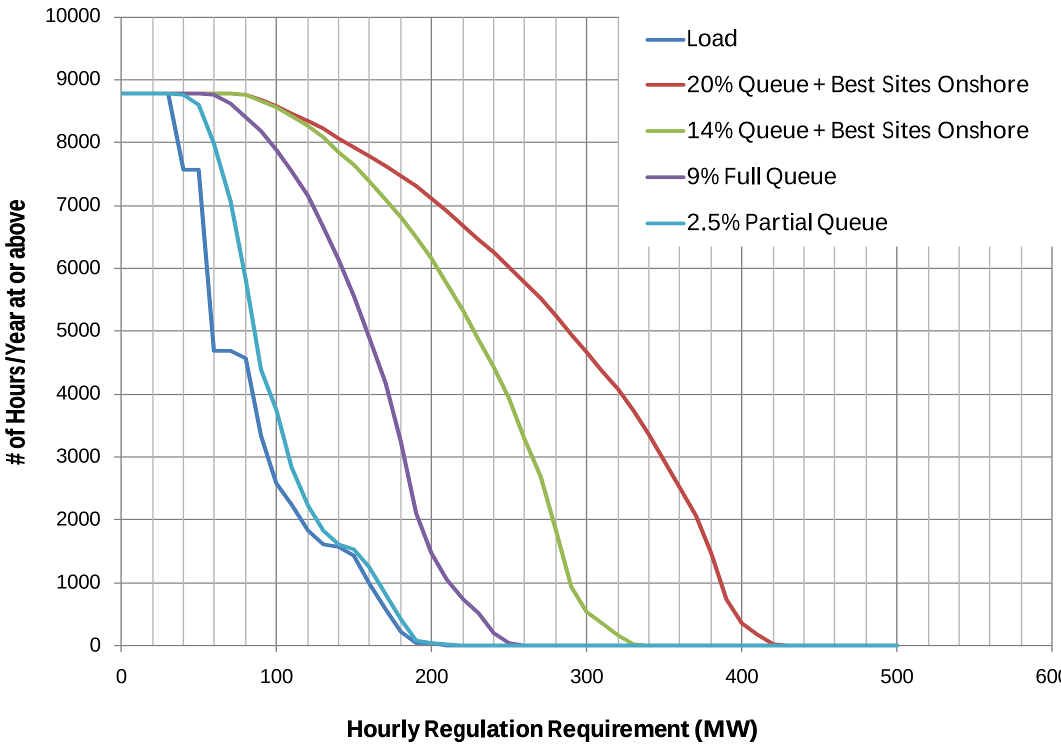

Figure 0–3 Regulation Requirements with Increasing Wind Energy Penetration

At 20% wind energy penetration, the average regulation requirement is estimated to increase from approximately 80 MW without wind, to a high of approximately 315 MW with 20% wind depending on the differences within the scenario. At lower penetration levels, the incremental regulation requirement is smaller. The hourly analysis indicates average regulation requirements would increase to a high of approximately 230 MW with 14% wind energy penetration. At 9% wind energy penetration, the average regulation would increase to approximately 160 MW. At the lowest wind penetration studied (2.5%) average required regulation capability would increase to approximately 100 MW. Alternate calculation methods that include historical records of ACE performance, synthesized 1-minute wind power output, and ISO-NE operating experience suggest that the regulation requirement may increase less than these amounts.

There are some small differences in regulation impacts discernable amongst layouts at the same energy penetration levels. This can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenario layouts of wind generation exhibit higher variability from one ten-minute interval to the next. A number of factors could contribute to this result, including the relative size of the individual plants in the scenario layout (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines comprising the scenario, as more turbines would imply more spatial diversity. At the same time, however, the differences may be within the margin of uncertainty inherent in the analytical methodologies for calculating regulation impacts. Given these uncertainties, it is difficult to draw concrete conclusions regarding the relative merits of one scenario layout over the others.

ISO-NE routinely analyzes regulation requirements and makes adjustments. As wind generation is developed in the market footprint, similar analyses will take place. Control performance objectives and the empirically observed operating data that includes wind generation should be taken into account in the regulation adjustment process.

ISO-NE's current practice for monitoring control performance and evaluating reserve policy should be expanded to explicitly include consideration of wind generation once it reaches a threshold where it is visible in operational metrics. A few methods by which this might be done are discussed in Chapter 4, and ISO-NE will likely find other and better ways as their experience with wind generation grows. ISO-NE should collect and archive high-resolution data from each wind generation facility to support these evaluations.

Analysis of these results indicates, assuming no attrition of resources capable of providing regulation capacity, that there may be adequate supply to match the increased regulation requirements under the wind integration scenarios considered. ISO-NE's business process is robust and is designed to assure regulation adequacy as the required amount of regulation develops over time and the needs of the system change.

Operating Reserves

Additional spinning and non-spinning reserves will be required as wind penetration grows. The analysis indicates that Ten Minute Spinning Reserve (TMSR) would need to be supplemented as penetration grows to maintain current levels of contingency response. Increasing TMSR by the average amount of additional regulation required for wind generation is a potential option to ensure that the spinning reserve available for contingencies would be consistent with current practice.

Using this approach, TMSR would likely need to increase by 310 MW for the 20% energy penetration scenarios, about 125 MW for 14% penetration, and about 80 MW for 9% penetration.

In addition to the penetration level, the amount is also dependent on the following factors:

- The amount of upward movement that can be extracted from the sub-hourly energy market – the analysis indicates that additional Ten Minutes Non-Spinning Reserve

(TMNSR), or a separate market product for wind generation, would be needed at 20% penetration

- The current production level of wind generation relative to the aggregate nameplate capacity, and
- The number of times per period (e.g., year) that TMSR and Thirty Minute Operating Reserve (TMOR) can be deployed – for the examples here, it was assumed that these would be deployed 10 times per period.

The amount of additional non-spinning reserve that would be needed under conditions of limited market flexibility and volatile wind generation conditions is about 300 MW for the 20% Best Sites Onshore case, and 150 MW for the 9% Energy Queue case. This incremental amount would maintain the TMNSR designated for contingency events per existing practice, where it is occasionally deployed for load changes. "Volatile wind generation conditions" would ultimately be based on ongoing monitoring and characterization of the operating wind generation. Over time, curves like those in Figure 4-5 would be developed from monitoring data and provide operators with an increasingly confident estimate of the expected amount of wind generation that could be lost over a defined interval.

The additional TMNSR would be used to cover potentially unforecasted extreme changes (reductions) in wind generation. As such, its purpose and frequency of deployment are different from the current TMNSR. This may require consideration of a separate market product that recognizes these differences. ISO-NE should also investigate whether additional TMOR could be substituted to some extent for the TMSR and/or TMNSR requirements related to wind variability.

Due to the increases in TMSR and TMNSR, overall Total Operating Reserve (TOR) increases in all wind energy scenarios. For the 2.5% wind energy scenario, the average required TOR increases from 2,250 MW to 2,270 MW as compared to the no wind energy scenario baseline. The average required TOR increases to approximately 2,600 MW with 14% wind penetration and about 2,750 MW with 20% penetration.

The need for additional reserves varies as a function of wind generation. Therefore, it would be advantageous to have a process for scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind generation. It may be inefficient to schedule additional reserves using the existing "schedule" approach, by hour of day and season of year, since that may result in carrying excessive reserves for most hours of the year. The process for developing and implementing a day-ahead reserves scheduling process may involve considerable effort and investigation of this process was outside the scope of the NEWIS.

Analysis of Hourly Operations

Production simulation analysis was used at an hourly time-step to investigate operations of the ISO-NE system for all the study scenarios under the previously stated assumptions of transmission expansion, no attrition of dispatchable resources, addition of resources that have cleared in the second Forward Capacity Auction, and the use of all of the technical capability of the system (i.e., exploiting all system flexibility). The results of this analysis indicate that integrating wind generation up to the 24% wind energy scenario is operationally feasible and may reduce average system-wide variable operating costs (i.e., fuel and variable O&M costs) in ISO-NE by $50 to $54 per megawatt-hour of wind energy[12]; however, these results are based on numerous assumptions and hypothetical scenarios developed for modeling purposes only. The reduction in system-wide variable operating cost is essentially the marginal cost of energy, which should not be equated to a reduction in $/MWh for market clearing price (i.e. Locational Marginal Prices--LMPs). Low-priced wind resources could displace marginal resources, but that differential is not the same as reductions in LMPs.

As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and therefore should not be considered the primary basis for evaluating the different scenarios.

Wind energy penetrations of 2.5%, 9%, 14%, 20%, and 24% were evaluated. As wind penetrations were increased up to 24%, there were increasing amounts of ramp down insufficiencies with up to approximately 540 hours where there may potentially be insufficient regulation down capability. There were no violations that occurred for the regulation up. The transmission system with the 4 GW overlay was adequately designed to handle 20% wind energy without significant congestion. The transmission system with the 8 GW overlay was adequately designed to handle 24% wind energy without significant congestion.

Wind generation primarily displaces natural-gas-fired combined cycle generation for all levels of wind penetration, with some coal displacement occurring at higher wind penetrations.

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[12] In essence, this is the cost to replace one MWh of energy from wind generation with one MWh of energy from the next available resource from the assumed fleet of conventional resources.

The study showed relatively small increases in use of existing pumped-storage hydro (PSH) for large wind penetrations; because balancing of net load—an essential requirement for large-scale wind integration—was largely provided by the flexibility of the natural-gas-fired generation fleet. It is possible that retirements (attrition) of some generation in the fleet would increase the utilization of PSH, but that was not examined in this study.

The lack of a price signal to increase use of energy storage is the primary reason the study showed small increases in the use of pumped-storage hydro in the higher wind penetrations. For energy arbitrage applications, like pumped storage hydro, a persistent spread in peak and off-peak prices is the most critical economic driver. The differences between on-peak and off-peak prices were small because natural-gas-fired generation remained on the margin most hours of the year. Over the past six years, GE has completed wind integration studies in Texas, California, Ontario, the western region of the United States, and Hawaii. In many of these studies, as the wind power penetration increases, spot prices tend to decrease, particularly during high priced peak hours. The off-peak hours remain relatively the same. Therefore, the peak and off-peak price spread shrinks and no longer has sufficient range for economic storage operation. An example of this can be seen in Figure 0–4. The figure shows the Locational Marginal Price (LMP) for the week of April 1, 2020, for the 20% Best Sites Onshore scenario, using year 2004 wind and load shapes. It also shows the LMP for a case with no wind generation. The price spread decreases substantially, which reduces the economic driver for energy storage due to price arbitrage.

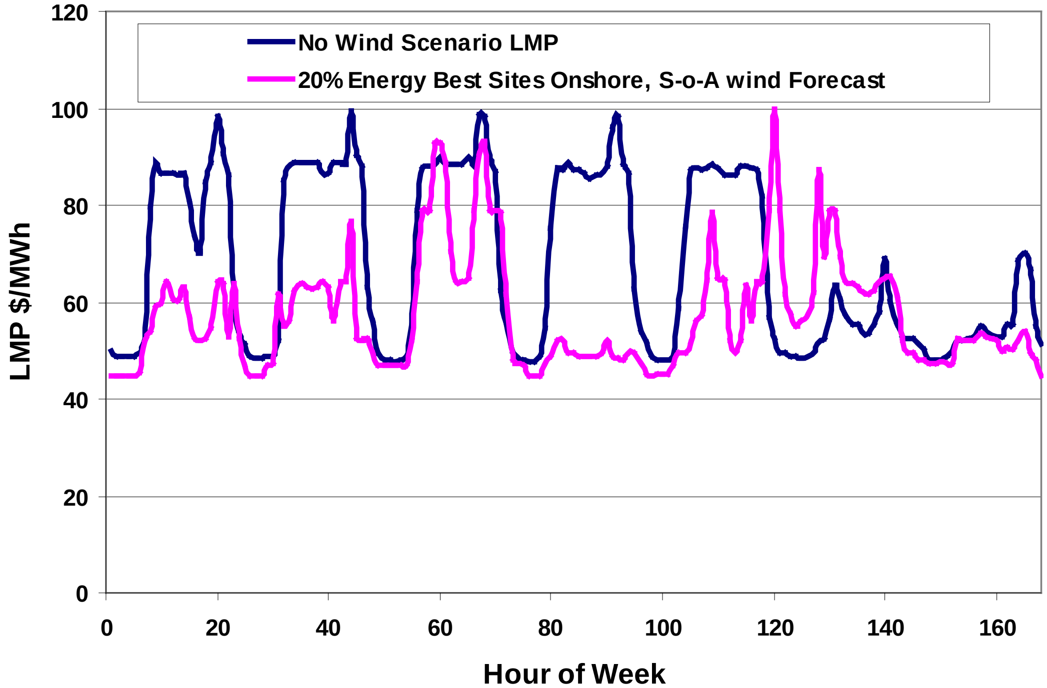

Figure 0–4 LMP for Week of April 1, Comparison of No Wind and 20% Wind Energy

With 20% wind energy penetration, the following impacts were observed on emissions and energy costs:

- NOx emissions were reduced by approximately 6,000 tons per year, a 26% reduction compared to no wind.
- SOx emissions were reduced by approximately 4,000 tons per year, a 6% reduction compared to no wind.
- CO_2 emissions were reduced by approximately 12,000,000 tons per year, a 25% reduction compared to no wind. (Wind generation will not displace other non- CO_2-producing generation, such as hydro and nuclear. Therefore, 20% energy from wind reduces the energy from CO_2-producing generation by 25 to 30%. Considering that wind generation primarily displaces natural-gas-fired generation in New England, the overall CO_2 production declines by 25% with 20% wind energy penetration).

- Average annual Locational Marginal Price (LMP) across ISO-NE[13] was reduced by
    - Best Sites Maritimes - $5/MWh
    - Best Sites Onshore - $6/MWh
    - Best Sites - $9/MWh
    - Best Sites Offshore - $9/MWh
    - Best Sites By State - $11/MWh

Variation in the LMP impact for the different layout alternatives results from the differences in the monthly wind profile as well as the daily profile. For example, the Maritimes layout alternative has slightly less energy in the summer than the other scenarios. Also, the Maritimes has less energy in the afternoon to early evening period, than the other scenarios when looking at the daily average summer profile. As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and actual changes in fuel prices, transmission system topology, and resource flexibility will have significant impacts on these results.

Revenue reductions for units not being displaced by wind energy is roughly 5%-10%, based on lower spot prices. For units that are being displaced, their revenue losses are even greater. This will likely lead to higher bids for capacity and may lead to higher bids for energy in order to maintain viability. The correct market signals must be in place in order to ensure that an adequate fleet of flexible resources is maintained.

The study scenarios utilized the transmission system overlays originally developed for the Governors' Study. With these transmission overlays, some scenarios exhibited no transmission congestion and others showed only a few hours per year with transmission congestion. This suggests that somewhat less extensive transmission enhancements might be adequate for the wind penetration levels studied, although further detailed transmission planning studies would be required to fully assess the transmission requirements of any actual wind generation projects.

[13] Based on the hourly marginal unit price. The results also do not account for other factors that may change business models of market participants.

Capacity Value of Wind Generation

Table 0–1 summarizes the average three-year capacity values for the total New England wind generation for all the scenarios analyzed in this study as calculated using the Loss of Load Expectation (LOLE) methodology where wind generation is treated as a load modifier. As mentioned in the NEWIS Task 2 report, three years of data only give some indication as to the variability of the effective capacity of wind generation from year to year. Along with the effective capacity of each scenario, Table 0–1 also includes in brackets the percent of the installed capacity that is offshore for that scenario.

Wind capacity values can vary significantly with wind profiles, load profiles, and siting of the wind generation. For example, the 20% Best Sites Onshore scenario has a wind generation capacity value of 20% while the corresponding 20% Best Sites Offshore scenario has a 32% capacity value. The capacity value of wind generation is dominated by the wind performance during just a few hours of the year when load demand is high. Hence, the capacity value of wind generation can vary significantly from year to year. For example, the 20% Best Sites Offshore scenario had wind capacity values of 27%, 26% and 42% for 2004, 2005 and 2006 wind and load profiles, resulting in the 32% average capacity value shown in Table 0–1.

Table 0–1 Summary of Wind Generation Capacity Values by Scenario and Energy Penetration

Scenario	3-Year Average Capacity Value (%) [% Offshore]	14% Energy 3-Year Average Capacity Value (%) [% Offshore]	20% Energy 3-Year Average Capacity Value (%) [% Offshore]
2.5 % Energy	36% [40%]		
9% Energy (Queue)	28% [20%]		
Onshore		23% [12%]	20% [8%]
Maritimes		26% [13%]	26% [9%]
Best by States		28% [15%]	26% [29%]
Best Sites		35% [47%]	34% [51%]
Offshore		34% [45%]	32% [58%]

High-Level Comparison of Scenario Layouts

For a given penetration of wind energy, differences in the locations of wind plants had very little effect on overall system performance. For example, the system operating costs and operational performance were roughly the same for all the 20% wind energy penetration scenarios analyzed. This is primarily because all the wind layout alternatives had somewhat similar wind profiles (since all of the higher penetration scenarios included the wind generation from the Full Queue), there was no significant congestion on the assumed transmission systems, and the assumed system had considerable flexibility, which made it robust in its capability of managing the uncertainty and variability of additional wind generation across and between the studied scenarios.

The individual metrics (e.g., prices, emissions) are useful in comparing scenarios, but should not be used in isolation to identify a preferred scenario or to predict actual future results.

Offshore wind resources yielded higher capacity factors than onshore resources across all scenarios and also tended to better correlate with the system's electric load. The study indicates that offshore wind resources would have higher capital costs, but generally require less transmission expansion to access the electric grid. Some scenarios with the lowest predicted capital costs (for wind generation only) also required the most amount of transmission because the resources are remote from load centers and the existing transmission system.

Some scenarios that showed the least transmission congestion also required the greatest investment in transmission, so congestion results should not be evaluated apart from transmission expansion requirements. Some scenarios that showed the greatest reductions in LMPs and generator emissions also used wind resources with low capacity factors, which would result in higher capital costs. The complete results are described in the full report.

Recommended Changes to ISO-NE Operating Rules and Practices

Capacity Value: Capacity value of wind generation is a function of many factors, including wind generation profiles for specific wind plants, system load profiles, and the penetration level of wind generation on the ISO-NE system. ISO-NE currently estimates the capacity value using an approximate methodology based on the plant capacity factor during peak load hours. This methodology was examined in Chapter 6 and gives an overall reasonable approximation across the scenarios studied. Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE monitor a comparison between its current approximate method and the LOLE/ELCC as operational experience is gained. As wind penetration increases, the Installed Capacity Requirement (ICR) may not accurately account for the intermittent nature of wind resources. GE recommends that the ISO evaluate potential improvements to the calculation of capacity values for wind resources. Given that the capacity value of wind is significantly less than that of typical dispatchable resources, much of the conventional capacity may be required regardless of wind penetration (Section 6.5).

Regulation: ISO-NE presently schedules regulation by time of day and season of year. This has historically worked well as regulation requirements were primarily driven by load, which has predictable diurnal and seasonal patterns. Wind generation does not have such regular patterns. At low levels of wind penetration, the existing process for scheduling regulation should be adequate, since the regulation requirement is not significantly affected by wind. However, with higher penetrations of wind generation (above 9%), it will likely become advantageous to adjust regulation requirements daily, as a function of forecasted and/or actual wind generation on the ISO-NE system. Due to the additional complexity of accommodating large-scale wind power, it is recommended that ISO-NE develop a methodology for calculating the regulation requirements for each hour of the next day, using day-ahead wind generation forecasts.

Determination of actual regulation requirements will need to grow from operating experience, similar to the present methods employed at ISO-NE. (See Section 4.4.3)

TMSR: Spinning reserve is presently dictated by largest contingency (typically 50% of 1,500 MW, the largest credible contingency on the system). ISO-NE presently includes regulation within TMSR. With increased wind penetration, regulation requirements will increase to a level where this practice may need to be changed – probably before the system reaches 9% wind energy penetration. Either regulation should be allocated separately from TMSR, or TMSR should be increased to cover the increased regulation requirements. The latter alternative was assumed for this study, and TMSR values in this report reflect that. (See Section 4.5.1)

TMNSR: Analysis of the production simulations for selected scenarios revealed that additional TMNSR might be needed to respond to large changes in wind generation over periods of tens of minutes to an hour or more. Given the assumption of no attrition of resources, displacement of marginal generation by wind energy may help to ensure that this capacity is available. In other words, some resources that are displaced by wind may be able to participate as fast start TMNSR—if those resources are assumed to continue to be available. A mechanism for securing this capacity as additional TMNSR during periods of volatile wind generation (as shown in the statistical analysis and the characterizations developed for the operating reserve analysis) may need to be developed. The use of TMOR instead of and/or in combination with TMNSR should be investigated (See Section 4.5.3).

Wind Forecast: Day-ahead wind forecasting should be included in the ISO-NE economic day-ahead security constrained unit commitment and reserve adequacy analysis. At the present level of wind penetration, this practice is not critical. At larger penetrations, if wind forecasts are not included in the economic day-ahead unit commitment, then conventional generation may be overcommitted, operating costs may be increased, LMPs may be depressed, the system may have much more spinning reserve margin than is necessary, and wind generation may be curtailed more often than necessary. Analysis performed for the NEWIS indicates that these effects, and hence the case for implementation of a wind power forecast, grows as wind power penetrations increase. Intra-day wind forecasting should also be performed in order to reduce dispatch inefficiencies and provide for situational awareness.

It would also be beneficial for ISO-NE to publish the day-ahead wind forecast along with the day-ahead load forecast, as this would contribute to overall market efficiency. Current practices for publishing the load forecast should be followed for publishing the wind forecast, subject to confidentiality requirements. This allows generation market participants to see the net load forecast and bid accordingly, just as they do with load today (See Section 5.2.4).

Wind Generation and Dispatch: Production simulation results showed increased hours of minimum generation conditions as wind penetration increases, which, given the policy support schemes for wind generation, implies increased frequency of negative LMPs. ISO-NE should not allow wind plants to respond in an uncontrolled manner to negative LMPs (e.g., as self-scheduled resources). Doing so may cause fast and excessive self-curtailment of wind generation. That is, due to their rapid control capability, all affected wind plants could possibly reduce their outputs to zero within a few minutes of receiving an unfavorable price signal. ISO-NE should consider adopting a methodology that sends dispatch signals to wind plants to control their output in a more granular and controlled manner (e.g., with dispatch down commands or specific curtailment orders). This method is recommended in the Task 2 report. NYISO has already implemented a similar method (See Section 5.2.1 for a discussion on the frequency of minimum generation issues).

System Flexibility: Increased wind generation will displace other supply-side resources and reduce flexibility of the dispatchable generation mix—in a manner that is system specific. Any conditions that reduce the system flexibility will potentially, negatively impact the ability of New England to integrate large amounts of wind power. Factors that could potentially reduce system flexibility can be market, regulatory, or operational practices, or system conditions that limit the ability of the system to use the flexibility of the available resources and can include such issues as: strict focus on (and possibly increased regulation of) marginal emissions rates as compared to total overall emissions, decreased external transaction frequency and/or capability, practices that impede the ability of all resources to provide all types of power system products within each resource’s technical limits, and/or long-term outages of power system equipment or chronic transmission system congestion.

Strict focus on marginal emissions rates can reduce system flexibility by encouraging generators to operate in a manner that reduces their flexibility (e.g., reducing allowed ramp rates or raising minimum generation levels in order to limit marginal emissions rates) and ignores the fact that as non-emitting resources are added to the system the overall level of emissions is reduced. Due to the variability and imperfect predictability of resources like wind power, dispatchable resources may need to be utilized in different operational modes that in some instances and/or during some hours may actually increase these units' emissions rates (in terms of tons of emittant per MWh of electrical energy), however the total emissions of the system will be reduced. The effects of the increases in marginal emissions rates are expected to be several orders of magnitude smaller than the effect of the overall reductions in emissions. Reduced frequency and/or capability of external interchange limits the ability of balancing areas to share some of the effects of wind power's variability and uncertainty with neighboring systems that at any given time might be better positioned to accommodate these effects. Practices that limit the ability of resources to participate in the power system markets to the full extent of their technical capability may cause the system to operate in a constrained manner, which reduces system flexibility. Self-scheduled generation reduces the flexibility of the dispatchable generation resource and can lead to excessive wind curtailment at higher penetrations of wind generation. It is recommended that ISO-NE examine its policies and practices for self-scheduled generation, and possibly change those policies to encourage more generation to remain under the control of ISO-NE dispatch commands. System flexibility can also be negatively impacted due to expected as well as unforeseen operational conditions of the system that reduce the ability to access and/or utilize the technical flexibility of the system resources. Examples of operational conditions that can negatively impact system flexibility include the long-term outage of resources that provide a large portion of the flexibility on the system, and chronic transmission system congestion or stability and/or voltage constraints along important transmission corridors.

Operating Records: It is recommended that ISO-NE record and save sub-hourly data from existing and new wind plants. System operating records, including forecasted wind, actual wind, forecasted load, and actual load should also be saved. Such data will enable ISO-NE to benchmark actual system operation with respect to system studies. ISO-NE should also periodically examine and analyze this data to learn from the actual performance of the ISO-NE system.

Other Observations from Study Results

Flexible Generation: The ISO-NE system presently has a high percentage of gas-fired generation, which can have good flexibility characteristics (e.g., ramping, turn-down). Using the assumed system, the results showed adequate flexible resources at wind energy penetration levels up to 20%. Also using the assumed system, there are periods of time in the 24% wind energy scenario when much of the natural-gas-fired generation is displaced by the wind generation, leaving less flexible coal and nuclear operating together with the wind generation. In this study, physical limits were used to determine how much units could be turned down when system conditions required such action. ISO-NE will need to be diligent in monitoring excessive self-scheduling, which could limit the apparent flexibility of the generation fleet. ISO-NE may need to investigate operating methods and/or market structures to encourage the generation fleet to make its physical flexibility available for system operations (See Section 5.2.1.2).

Energy Storage: Study results showed no need for additional energy storage capacity on the ISO-NE system given the flexibility provided by the assumed system. However, the need for energy storage may increase if there is attrition of existing flexible resources needed to balance net load and dispatchable resources. It is commonly believed that additional storage is necessary for large-scale wind integration. In New England, wind generation displaces natural-gas-fired generation during both on peak and off-peak periods. Natural-gas-fired generation remains on the margin, and the periodic price differences are usually too small to incent increased utilization of pumped storage hydro-type energy storage, which is why the study results showed PSH utilization increasing only slightly and only at higher levels of wind penetration.

Additional energy storage may have some niche applications in regions where some strategically located storage facilities may economically replace or postpone the need for transmission system upgrades (i.e., mitigate congestion). Also, minute-to-minute type storage may be useful to augment existing regulation resources. But additional large-scale economic arbitrage type storage, like PSH, is likely not necessary (See Section 5.2.1).

Displacement of Energy from Conventional Generation: Energy from wind generation in New England primarily displaces energy from natural-gas-fired generation. Although displacement of fossil-fueled generation might be one of the objectives of regional energy policies, a consequence is that it may radically change the market economics for all resources on the system, but especially for the natural-gas-fired generation resources that are displaced. Although their participation in the ISO-NE market will continue to be important, to serve both energy (especially during summer high-load periods) and capacity requirements, the balance of revenues that resources receive from each of these market segments will change. Since total annual energy output from conventional resources would decline and energy prices also would decline under the study assumptions, capacity prices from these plants will likely need to increase if they are to remain economically viable and therefore able to provide the flexibility required for efficient system operation (See Section 5.2.1).

Dynamic Scheduling: Dynamic scheduling involves scheduling the output of a specific plant or group of plants in one operating area on transmission interties to another operating area. Dynamic scheduling implies that the intertie flows are adjusted on a minute-to-minute basis to follow the output of the dynamically scheduled plants. Most scenarios in this study included all necessary New England wind resources within the ISO-NE operating area, and therefore did not require dynamic scheduling. The Maritimes scenarios assumed that a portion of the ISO-NE wind generation would be imported from wind plants in the Canadian Maritimes using dynamic scheduling, so that ISO-NE would balance the variability due to the imported wind energy. The results showed, given the study assumptions, that ISO-NE has adequate resources to balance the imported Maritimes wind generation.

Load and Distributed Wind Forecasting: This study assumed that load forecast accuracy would remain the same as wind penetration increases. However, a portion of the wind generation added to the ISO-NE system will be distributed generation that may not be observed or controlled by ISO-NE. It will essentially act as a load-modifier. As such, distribution-connected wind generation will negatively affect the accuracy of load forecasts. As long as the amount of this distribution-connected wind generation is fairly small and if ISO-NE is able to account for the magnitude and location of distribution-connected wind plants, it should be possible to include a correction term into the load-forecasting algorithm (See Section 5.3.3).

Technical Requirements for Interconnection of Wind Generation

The Task 2 report, "Technical Requirements for Wind Generation Interconnection and Integration," includes a set of recommendations for interconnecting and integrating wind generation into the ISO-NE power grid. That report was completed before the statistical, production simulation, and reliability analyses of the NEWIS scenarios were performed. The recommendations contained in the Task 2 report were re-examined after the NEWIS scenario analysis was completed and the analysis performed reinforces the need to implement those recommendations. It was determined that no changes to the Task 2 recommendations are warranted at this time based on the results of the scenario analysis. A few of the most significant Task 2 recommendations are summarized below.

Active Power Control: Wind plants must have the capability to accept real-time power schedule commands from the ISO for the purpose of plant output curtailment. Such control would most often be used during periods when wind generation is high and other generating resources are already at minimum load.

AGC Capability: Wind plants should be encouraged to have the capability to accept Automatic Generation Control (AGC) signals, which would enable wind plants to provide regulation. The current ISO-NE market product requires symmetrical regulation, which means that wind generation could only provide this service when it is curtailed. Some other systems have asymmetrical regulation markets where wind generation could be quite effective at down-regulation even under non-curtailed operation, such as when other generation resources have been dispatched down to minimum load and/or other down regulation resources have been exhausted.

Centralized Wind Forecast: ISO-NE should implement a centralized wind power forecasting system that would be used in a manner similar to the existing load forecasting system. Information from the day-ahead wind forecast would be used for unit commitment as well as scheduling regulation and reserves. ISO-NE should also implement intra-day forecasting (e.g. an early warning ramp forecasting system) that will provide improved dispatch efficiency and situational awareness, and alert operators to the likelihood and potential magnitude and direction of wind ramp events.

Communications: Wind plants should have the same level of human operator control and supervision as similar sized conventional plants. Wind plants should also have automated control/monitoring functions, including communications with ISO-NE, to implement operator commands (active/reactive power schedules, voltage schedules, etc.) and provide ISO-NE with the data necessary to support wind forecasting functions. The Task 2 report contains detailed lists of required signals.

Capacity Value: Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE should monitor a comparison between its current approximate method and the ELCC method for determining the aggregate capacity value of all wind generation facilities in the operating area, and the calculation should be updated periodically as operational experience is gained. Historical data should be used for existing plants; data from mesoscale simulations could be used for new plants until sufficient operation data is available.

If the recommendations developed and discussed in the Task 2 report are not implemented, it is highly likely that operational difficulties will emerge with significant amounts of wind generation. Two recent examples of some Balancing Authorities experiences with a lack of effective communication and control and/or a lack of an effective wind power forecast and the resulting operational difficulties include having to:

- Implement load-shedding[14] (albeit contracted-for load-shedding), and
- Spill water for hydro resources.[15]

Another example of operational difficulties that could arise includes the experience of some European TSO's with older windplants' lack of ability to participate in voltage control causing the system to sometimes be operated in very inefficient dispatch modes. This lack of voltage control participation, as well as the lack of communication and control capability, was found to have exacerbated the severe European UCTE disturbance in November of 2006[16].

Future Work

Several areas of interest that are candidates for further investigation are suggested by the study results. These include:

Transmission system overlay refinement. The transmission system overlays developed for the Governors' Study and used in this study were shown, based on thermal limit analysis only, to have adequate capacity for all scenarios. In fact, some NEWIS scenarios use transmission overlays that were "one size smaller" than those used for the Governors' Study scenarios, and still no or only minimal congestion was observed. Detailed and extensive transmission studies that include stability and voltage limits will be required in order to proceed with specific wind projects or large-scale wind integration.

A future study could start by analyzing wind penetration scenarios using a "copper sheet" approach to evaluate magnitude and duration of congestion due to existing transmission limitations. This would guide the design of specific transmission additions to minimize congestion with increased levels of wind generation.

Sub-hourly performance during challenging periods. A more in-depth investigation of the dynamic performance of the system under conditions of high stress, such as coincident high penetration and high variability could be pursued using additional simulation tools that have

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[14] ERCOT Event on February 26, 2008: Lessons Learned, available at: http://www1.eere.energy.gov/windandhydro/pdfs/43373.pdf.

[15] "Wind power surge forces BPA to increase spill at Columbia Basin dams" available at: http://www.oregonlive.com/environment/index.ssf/2008/07/columbia_basin_river_managers.html

[16] Final report: System Disturbance on 4 November 2006, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf

been developed recently. Both long-term dynamic (differential equations) simulations and fine time resolution quasi-static time simulations could shed additional insight into the frequency, ACE, CPS2 and other performance measures of the system, as well as providing more quantitative insight into incremental maneuvering duties imposed on the incumbent generation and the impacts of this increased maneuvering on such quantities of interest as emissions and increased generator maintenance. Such analysis could be part of an assessment of possible increased operating costs associated with maneuvering (beyond those captured in the MAPS analysis).

Impacts of Cycling and Maneuvering on Thermal Units. Costs of starting and stopping units, and static impacts on heat rate were reflected in the study to the extent presently possible. However, the understanding of these impacts and the quantification of costs is still inadequate throughout the industry. A deeper quantification of the expected cycling duty, the ability of the thermal generation fleet to respond and an investigation of the costs – O&M, emissions, heat rate, and loss-of-life – would provide clearer guidance for both operating and market design strategies.

Economic Viability and Resource Retirements. The incumbent generating resources, particularly natural-gas-fired generation, will be strongly impacted by large-scale wind generation build-outs like those considered in the study. Investigation should be performed to determine the revenue impacts, and their implications for the long-term viability of the system resources that provide the flexibility required to integrate large-scale wind power. Such investigation could include examination of impact of possible resource retirements driven by reduced energy sales and revenues, and the efficacy of possible market structures for maintaining the necessary resources to maintain system reliability.

Demand Response. A deeper analysis of the efficacy and limitations of various demand-side options for adding system flexibility could help define directions and policies to pursue. Temporal aspects of various demand response options could be further investigated. For example, heating and cooling loads have significant time and duration constraints that will govern their effectiveness for different classes of response. Similarly, some types of commercial and industrial loads may offer options and limitations for providing various ancillary services that will be needed.

Weather, Production, and Forecasting Data. This study was based on sophisticated meso-scale wind modeling. The ISO should start to accumulate actual field data from operating wind plants, from met masts, and from actual forecasts. Further investigation and refinement of study results or use of such data in the suggested sub-hourly performance analysis, would increase confidence in results and may allow for further refinement of ISO plans and practices.

Network Planning Issues. This study was not a transmission planning study. The addition of significant wind generation, particularly multiple plants in close electrical proximity in parts of the New England grid that may be otherwise electrically remote (for example the addition of significant amounts of wind generation in Maine) poses a spectrum of application questions. A detailed investigation of a specific subsystem within New England considering local congestion, voltage control and coordination, control interaction, islanding risk and mitigation, and other engineering issues that span the gap between "interconnection" and "integration" would provide insight and help establish a much needed set of practices for future planning in New England (and elsewhere).

1 Introduction

1.1 Overview of ISO-NE

ISO New England Inc. (ISO-NE) is the not-for-profit corporation that serves as the Regional Transmission System Operator (RTO) for New England. ISO-NE is responsible for the reliable operation of New England's power generation, demand response and transmission system, administers the region's wholesale electricity markets, and manages the comprehensive planning of the regional power system. ISO-NE has the responsibility to protect the short-term reliability and plan for the long-term reliability of the Balancing Authority Area, a six-state region that includes approximately 6.5 million businesses and households.

The New England electricity market consists of an energy market (i.e., Day-Ahead and Real-Time Energy Markets), ancillary services markets (i.e., Forward Reserve Market and Regulation), and a capacity market (i.e., Forward Capacity Market). Through these competitive wholesale markets, the ISO ensures the availability of electricity to meet the demands of the region.

Through the Day-Ahead Energy Market (DAM) and Real-Time Energy Market (RTM), the ISO coordinates the commitment and dispatch of resources by economically scheduling resources to provide energy and ancillary services on the basis of supply offers, bid-in load, submitted transactions, and transmission information. The DAM produces financially binding obligations. Resources generally are committed to operate in real-time consistent with their DAM schedule. To the extent that insufficient resources clear in the DAM to meet ISO-NE's forecasted real-time load or expected real-time reliability requirements, ISO-NE commits additional resources in the RTM, which is effectively a balancing market. In real-time, the dispatch and scheduling software co-optimizes the dispatch of resources to provide energy and operating reserves. The ISO also runs the Regulation Market in real-time, which schedules resources to provide regulation services. Dispatch instructions are sent out to all of the resources in the New England Balancing Authority Area consistent with their offer data, limits, and constraints to meet changing load and ancillary service requirements throughout the Operating Day.

Commitment and dispatch of the system is done on five-minute intervals using a security constrained economic commitment and dispatch. This approach recognizes transmission constraints in the commitment and dispatch solutions. Both the DAM and RTM generate Locational Marginal Prices (LMP), which reflects the marginal cost of meeting the next increment of load at a location while respecting transmission constraints. The RTM also produces locational reserve prices by reserve category and system-wide regulation prices. The reserve prices reflect the opportunity cost of re-dispatching the system to maintain reserves. Regulation prices reflect the offer of the most expensive resource selected to provide regulation in an hour.

The ISO also administers a Forward Capacity Market (FCM) and a Locational Forward Reserve market. The FCM is a forward market for physical resources through which the ISO procures an amount of capacity equal to the Installed Capacity Requirements (ICR) for New England three years prior to the time the capacity is needed. The Locational Forward Reserve Market (FRM) is the mechanism by which the ISO procures reserve capacity in New England for dispatch during system contingencies.

Intermittent Power Resources[17] (IPRs) (e.g. wind power) are not required to participate in the DAM, but are permitted to do so. Regardless of whether or not they offer into the DAM, Intermittent Power Resources are not subject to deviations or imbalance charges in the RTM; though if IPRs choose to participate in the DAM they must make up any shortfall in production by purchasing power in real-time. The Market Rules also allow IPRs to participate in the FCM by having mechanisms in place through which ISO-NE can confirm the claimed capacity ratings of the IPRs for the purpose of qualifying in the Forward Capacity Auction (FCA).[18]

1.2 Key Drivers of Wind Power

The large-scale use of wind power is becoming a norm in many parts of the world. The increasing use of wind power is due to the emissions-free electrical energy it can generate; the speed with which wind power plants can be constructed; the generation fuel source diversity it adds to the resource mix; the long-term fuel-cost-certainty it possesses; and, in some instances, the cost-competitiveness of modern utility-scale wind power. Emissions-free generation helps meet environmental goals, such as Renewable Portfolio Standards (RPS)[19] and greenhouse gas

[17] See ISO Tariff, Section I.2 (defining “Intermittent Power Resources” to include those resources “whose output and availability are not subject to the control of the ISO or the plant operator because of the source of fuel (e.g., wind, solar, run-of-river hydro),” among others).

[18] See id. at Section III.13.1.1.2.2.6.

[19] Each state in New England has adopted a renewable portfolio standard, except for Vermont, which has set renewable energy goals. RPSs set growing percentage-wise targets for electric energy supplied by retail suppliers to come from renewable energy sources. For a further description of New England related policies potentially affecting wind power see, for example, the ISO-NE Regional System Plan. RSP10 is available at: http://www.iso-ne.com/trans/rsp/index.html.

control. Once the permitting process is complete, some wind power plants can be constructed in as little as three to six months, which facilitates financing and quick responses to market signals. Wind power, with a fuel cost fixed at essentially zero, can contribute to fuel-cost certainty and would reduce New England's dependence on natural gas. In New England, the economics of wind power are directly affected by the outlook for the price of natural gas; higher fuel prices generally spur development of alternative energy supplies while lower fuel prices generally slow such development. Wind power development also is directly affected by environmental policy drivers such as restrictions on generator emissions or renewable energy generation targets.

While wind can provide low-priced zero-emissions energy, the variability of wind resources and the uncertainty with which the amount of power produced can be accurately forecasted poses challenges for the reliable operation and planning of the power system. Many favorable sites for wind development are remote from load centers. Development of these distant sites would likely require significant transmission development, which may not appear to be economical in comparison to conventional generation resources (at current prices) and could add complexity to the operations and planning of the system. The geographical diversity of wind power development throughout New England and its neighboring systems in New York and the eastern Canadian provinces would mitigate some of the adverse impacts of wind resource variability if the transmission infrastructure, operating procedures, and market signals were in place to absorb that variability across a larger system. Several Elective and Merchant Transmission Upgrades are in various stages of consideration to access these wind and other renewable resources.

1.3 Growth of Wind Power in New England

As of October 2010, approximately 270 megawatts (MW) of utility-scale wind generation are on line in the ISO New England system, of which approximately 240 MW are biddable assets. New England has approximately 3,200 MW of larger-scale wind projects in the ISO Generator Interconnection Queue more than 1,000 MW of which represent offshore projects and more than 2,100 MW of which represent onshore projects.[20] The wind capacity numbers in the ISO queue are based on nameplate ratings. Figure 1–1shows a map of planned and active wind projects in New England. As an upper bound of all potential wind resources—and not including the

[20] The 3,200 MW of wind in the queue is as of October 1, 2010, and includes projects in the affected non-FERC queue.

feasibility of siting potential wind projects—New England holds the theoretical potential for developing more than 215 gigawatts (GW) of onshore and offshore wind generation.[21]

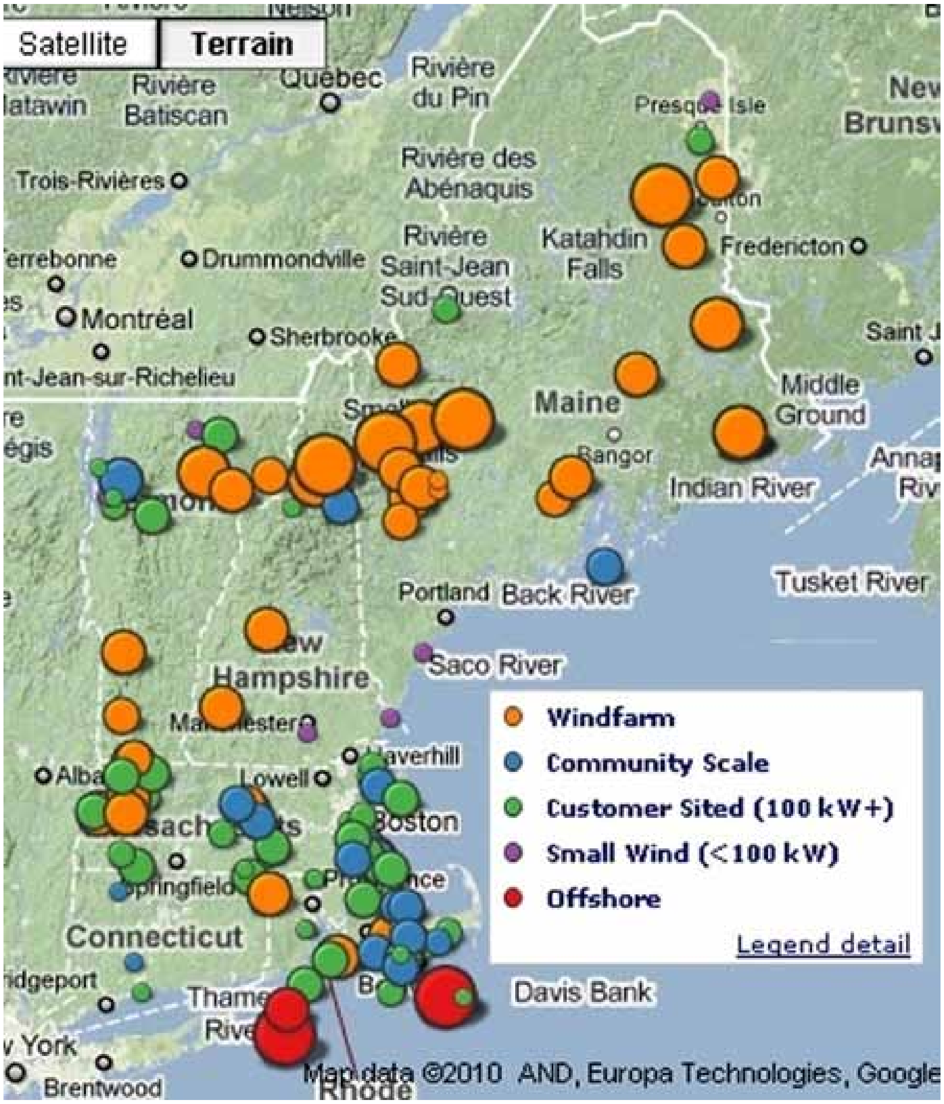

Figure 1–1 Planned and active wind projects in New England, 2010. Source: Sustainable Energy Advantage

1.4 The Governor's Economic Study

In 2009, the ISO completed the Scenario Analysis of Renewable Resource Development (the "Governors' Economic Study") – a comprehensive analysis for the integration of renewable

[21] 2009 Northeast Coordinated System Plan (May 24, 2010); http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html.

resources over a long-term horizon, performed at the request of the Governors of the six New England states.[22] The Governors' Economic Study identified economic and environmental impacts for a set of scenario analyses that assumed the development of renewable resources in New England. The study also identified the potential for significant wind power development in the New England states, the effective means to integrate this wind power development into the grid, and related preliminary transmission cost estimates, it did not evaluate operational impacts. Certain scenarios analyzed in the study indicated that, through development in the Northeast, New England and its neighbors could effectively meet the renewable energy goals of the region. Other scenarios showed that the region could be a net exporter of renewable energy.

The Governors' Economic Study ultimately informed the New England Governors' Renewable Energy Blueprint (the "Blueprint"), adopted last year by the six New England state governors.[23] The Blueprint sets forth policy objectives for the development of renewable resources in the Northeast that could ultimately lead to substantial penetration of wind power in New England.

1.5 Operational Effects of Large-scale Wind power

Large-scale wind integration adds complexity to power system operations by introducing a potentially large quantity of variable-output resources and the new challenge of forecasting wind power in addition to load.

The power system is designed and operated in a manner to accommodate a given level of uncertainty and variability that comes from the variability of load and the uncertainty associated with the load forecast as well as the uncertainty associated with the outage of different components of the system, such as generation or transmission. Due to a long familiarity with load patterns and the slowly changing nature of those patterns, the variability of the load is quite regular and well understood. The result is that the power system has been planned to ensure that different types of resources are available to respond to the variability of the load (e.g., baseload, intermediate, and fast-start resources have come into service) and the uncertainty associated with the load forecast is generally very small. The uncertainty associated

[22] The Governor's Economic Study is available on the ISO's website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.
The Governor's Economic Study was conducted pursuant to the Regional System Planning Process established in Attachment K of the ISO OATT.

[23] See Blueprint Materials, available at: http://www.nescoe.com/Blueprint.html.

with equipment outages is of a more discrete and “event” type nature that can be handled in a relatively deterministic fashion. This is the basis of contingency analysis where lists of credible contingencies are evaluated on a frequent periodic basis for their effects on power systems operations.

The combination of wind power’s variability and the uncertainty of forecasting wind power make it fundamentally different from analyzing and operating other resources on the system. The weather patterns that drive the generation characteristics for wind power vary across many timescales and are loosely correlated with load. For example, ISO-NE experiences its peak loads during the summer months, while, as observed in this study, wind generation produces more energy during the winter months than in the summer. The uncertainty associated with wind generation is very different from the uncertainty associated with typical dispatchable resources. In general, uncertainty of energy supply from dispatchable conventional generation is due to forced unit outages due to equipment failures or other discrete events. Uncertainty in wind generation is more like uncertainty due to load. The amount of wind generation expected for the next day is forecasted in advance (just as load is forecasted in advance), and the amount of wind generation that actually occurs may be different from the forecasted amount, within the accuracy range of the forecast. In contrast, however, to forecasting of day-ahead load where typical average error is on the order of 1% to 3% Mean Absolute Error (MAE); the accuracy of state-of-the-art day-ahead wind forecasts is in the range of 15% to 20% MAE of installed wind rating. For small amounts of installed wind, load uncertainty dominates, but at higher penetrations of wind, forecast uncertainty becomes very important. In order to plan for the reliable operation of the power system, it is important to study how this combination of variability and associated uncertainty will affect power system operations far enough ahead of time for the effects to be quantified and any required mitigation measures to be put into service.

The loose correlation of wind and load requires the use of a new metric, “net load,” to study the impact of large-scale wind generation where the fleet of dispatchable resources is used to balance the time-synchronous variability and uncertainty of the load minus the output of the wind generation. When managing the power system, the output of variable resources such as wind power can be directly subtracted from the amount of load to be served, the dispatchable resources on the system are then used to serve this remaining (i.e., “net”) load in order to maintain the power system balance. The net load is then the true variability that must be managed with dispatchable resources and therefore it is the net load that must be studied when determining operational effects.

1.6 NEWIS Tasks and Analytical Approach

Anticipating the possible penetration of large-scale wind power in New England, ISO-NE also commissioned this comprehensive wind integration study in 2009 – the New England Wind Integration Study (the NEWIS) – to assess the operational effects of large-scale wind penetration in New England using statistical and simulation analysis of historical data.[24] ,[25] By focusing on the operational effects of large-scale wind integration, the NEWIS complements and builds on the results of the Governors' Economic Study.

The goals of the NEWIS were to determine the operational, planning and market impacts of integrating substantial wind generation resources for the New England Balancing Authority Area, with due consideration to the neighboring areas, as well as, the measures that may be available to ISO-NE for mitigating any negative impacts while enabling the integration of wind. The NEWIS also sets forth recommendations for implementing these measures. Additionally, the NEWIS identifies the potential operating conditions created or exacerbated by the variability and unpredictability of wind generation resources, and recommends potential corrective activities, recognizing the unique characteristics of the tightly integrated bulk power system in New England and the characteristic of wind generation resources. Consistent with the Governors' Economic Study, the NEWIS examines various scenarios of increasing wind power penetration up to approximately 12 GW of nameplate wind power.

In order to accomplish its goals, the NEWIS captures the unique characteristics of New England's bulk electrical system including load and ramping profiles, geography, system topology, supply and demand-side resource characteristics, and wind profiles and their unique impacts on system operations and planning with increasing wind power penetration. To facilitate the work of the NEWIS, it is broken into five tasks:

1. Wind Integration Study Survey
2. Technical Requirements for Interconnection
3. Mesoscale Wind Forecasting and Wind Plant Models

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[24] See NEWIS Materials, New England Wind Integration Study (NEWIS) Wind Scenario and Transmission Overlays, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/newis.pdf.

[25] The core project team included GE Energy Applications and Systems Engineering, EnerNex, and AWS Truepower. Many members of this team have extensive experience and have been among the pioneers of wind integration analysis.

4. Scenario Development and Analysis

5. Scenario Simulation and Analysis

The first task – Wind Integration Study Survey – involved a review of the experience gained and lessons learned from several previous domestic and international wind integration studies on bulk electric power systems (including ISO-NE studies such as phases I and II of the Technical Assessment of Onshore and Offshore Wind Generations Potential in New England (2007, 2008)[26] and the New England Electricity Scenario Analysis (2007)[27]) and actual wind integration experiences in bulk electric power systems. This task was completed with a presentation at the NEWIS project kickoff meeting. The project team has considered this information while developing detailed work plans for the other tasks.

The second task – Technical Requirements for Interconnection – includes the development of specific recommendations for technical requirements for wind generating resources. This task looks at wind power plants' ability to provide grid support functions such as their capability to reliably withstand low-voltage conditions, provide voltage support to the system, adjust megawatt output to support the operation of the system, provide ancillary service type products (e.g. regulation), and coordinate with other equipment and control schemes during disturbances. This task includes data and telemetry requirements, maintenance and scheduling requirements, high wind cutout behavior, and the development of best practice methods of the Effective Load Carrying Capability (ELCC) calculation used for establishing capacity values for global and incremental wind generation. This task also investigates and recommends wind power forecasting methods for both the very short-term timeframe (useful in real-time operations) and the short- to medium-term timeframe (useful in unit dispatch and day-ahead unit commitment), as well as the required accuracy for wind power forecasts, and implementation issues. This task was completed in fall 2009, with recommendations to ISO-NE detailed in a "Technical Requirements for Wind Generation Interconnection and Integration" report (the "NEWIS Technical Report").[28]

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[26] Available on ISO-NE's website located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/

[27] Available on ISO-NE's web site located at: http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/

[28] See NEWIS Technical Report, available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf. ISO-NE presented the recommendations

The third task – the Mesoscale Wind Forecasting and Wind Plant Models – was completed at the end of calendar year 2009. This task consists of the development of an accurate and flexible mesoscale hindcasting model for the New England and Maritime wind resource area (including offshore wind resources) that allows for the simulation of power system and wind generation operations and interactions (e.g., unit commitment, scheduling, load following, and regulation) over the timescales of interest. The model is designed to produce three years of realistic time-series of wind data in order to quantify the effects of inter-annual variability in wind generation and system-wide load. The database of wind resource and power data developed for the NEWIS along with a tool for interrogating and aggregating this database has been transferred to ISO-NE. This tool allows reuse of the mesoscale modeling data for further ISO-NE studies.

The fourth task – Scenario Development and Analysis – develops base case and wind generation scenarios in consultation with ISO-NE and stakeholders that includes potential and probable scenarios for wind power development for scenarios considering various levels of wind development: from wind power projects that are active and in advanced stages of the planning process (approximately 1.14 GW, nameplate) up to 20% to 24 % of the projected annual consumption of electric energy (approximately 9 GW to 12G W, nameplate). This task then builds on and expands the knowledge gained and tools developed in the tasks 1, 2, and 3 and the developed scenarios to perform a detailed evaluation of the impact of incremental wind generation variability and uncertainty on New England's bulk electric power system via statistical measures.

The fifth task – Scenario Simulation and Analysis – develops simulations and analysis of these scenarios in order to assess the measures needed to successfully integrate substantial wind generation, respectively. The simulations evaluate the use of on-line generation for day-ahead commitment, economic dispatch, load following, regulation, and contingency reserves; the production of air emissions; the effects of carbon cost; and the effects on LMPs. Sensitivity analyses include the impacts of varying levels of diversity of the wind portfolio on the performance of the electric power system.

The final two tasks – task four and five– were partially performed in parallel and completed in the fall of 2010.

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of the NEWIS Technical Report to New England stakeholders at the November 18, 2009 meeting of the Planning Advisory Committee ("PAC"). *These recommendations will be subject to the applicable stakeholder processes prior to implementation.*

The analysis performed in the NEWIS is both qualitative and quantitative, and is meant to provide a basis to judge whether the New England power system has adequate resources (supply and demand-side) to reliably incorporate a large amount of wind-generated power. Neighboring control area systems and wind power development will also influence ISO-NE's bulk electric power system and are therefore also represented in this study. Measures that would facilitate the integration of wind, such as changes to market rules, and the use of demand response also are studied. The evaluation also includes a review of the ISO-NE's market design considering a high penetration of wind generation and how the scenarios could affect system reliability and/or contribute to inefficient market operation of the bulk electric power system. Ultimately, this analysis leads to recommendations for modifying existing procedures, guidelines, and standards to reliably and efficiently accommodate the integration of new wind generation.

The results of this report will form some of the basis for the ISO's policies and practices that may result in changes to the ISO Tariff, Operating and Planning Procedures and Manuals. As stated earlier, ISO-NE has presented the work completed to date to stakeholders, and will continue to work with stakeholders to discuss the study's findings, and then complete a full stakeholder process within New England prior to implementing any final recommendations in the form of rule and procedure changes to support the integration of wind power.

In order to be clear about the interpretation of the methods used, results obtained, and any recommendations provided, it is important to recognize what the NEWIS is and what it is not. The NEWIS is neither a transmission planning study nor a blueprint for wind power development in New England, and large-scale wind power development might or might not occur in the region. The NEWIS takes a snapshot of a hypothetical future year where low, moderate, and large wind power penetrations are assumed. Feedback dynamics in markets, such as the impact of overall reduced fuel use and the changes in fuel use patterns on fuel supply and cost, were not analyzed or accounted for. It is not a goal of ISO-NE to increase the amount of any particular resource; instead the ISO's goal is to provide mechanisms to ensure that it can meet its responsibilities (stated above) for operating the system reliably, managing transparent and competitive power system markets, and planning for the future needs of the system, while providing a means to facilitate innovation and the fulfillment of New England's policy objectives. In this context the NEWIS is meant to investigate whether there are any insurmountable operational challenges that would impede ISO-NE's ability to accept large amounts of wind generation.

A fundamental assumption in the NEWIS is that the transmission required to integrate the hypothesized wind generation into the bulk power system would be available and that the wind power resources would interconnect into those bulk transmission facilities. The NEWIS is a system-wide transportation study and, as such, does not account for local issues. For example, even with the limited wind generation that currently exists on the ISO-NE system, there are some instances where local transmission constraints result in curtailment of wind facilities due to the typical development pattern of wind generation facilities in New England and their interconnection under the minimum interconnection standards process. Implementing the recommendations developed as a result of the NEWIS will not solve these issues, unless the aforementioned sizable transmission expansions were to be built and the wind generation facilities were to connect directly into those expansions.

Another important assumption is that the available portfolio of non-wind generation in New England and neighboring systems was held constant across all alternatives considered. Neither attrition nor addition of new non-wind generation was considered as modifications to the base case.

Furthermore, detailed and extensive engineering analysis regarding stability and voltage limits would be required in order to determine the viability of the hypothesized transmission expansions, which in themselves may require substantial effort to site and build. It is also important to note that implementing the recommendations developed during the second task of the NEWIS (e.g., wind power specific grid support functions, wind power forecasting, windplant modeling, and communications and control) are absolutely essential for the reliable integration of large-scale wind power into the New England power system.

Finally, in addition to the significant observations mentioned above, changes may be required to systems and procedures within the ISO organization that are yet to be determined. These changes would require additional analysis for increasing levels of wind penetration and for issues identified within New England, or beyond, as system operators gain experience with wind energy. The development, implementation, and operating costs associated with these changes are not accounted for in this study.

1.7 NEWIS Task Flow and External Review Process

Several levels of review were incorporated into the task flow of the NEWIS:

1. Stakeholder feedback (PAC)
2. Internal ISO-NE review (see Table 1–1)
3. Independent Technical Review Committee (TRC) of recognized experts (see Table 1–2)

Table 1–1 ISO-NE Team Members Participating in NEWIS

NEWIS ISO-NE Team Member	ISO NE Organization Unit/Title
Jon Black	System Operations, Intern
Wayne Coste	Resource Adequacy, Manager
Mike Henderson	Regional Planning & Coordination, Director
William Henson	System Operations, Senior Renewable Resource Engineer
Steven Judd	Area Transmission Planning, Engineer
Fred Letson	Renewable Resource Integration, Intern
Jonathan Lowell	Market Design, Principal Analyst
Xiaochuan Luo	Business Architecture & Technology, Principal Analyst
John Norden	System Operations, Director
James Platts	Regional Planning & Coordination, Lead Engineer
Mike Potishnak	System Operations, Principal Engineer

Table 1–2 Members of NEWIS Technical Review Committee

NEWIS TRC Member	Affiliation
Utama Abdulwahid	Senior Research Fellow at the University of Massachusetts Wind Energy Center (UMass WEC)
Michael Jacobs	NREL's National Wind Technology Center
Brendan Kirby	Consultant for AWEA, NREL, Oak Ridge National Laboratory (ORNL), Electric Power Research Institute, and various ISO/RTOs
Warren Lasher	ERCOT, Manager of Long-Term Planning and Policy
Michael Milligan	NREL's Systems Integration Team at the National Wind Technology Center
J. Charles Smith	Utility Wind Integration Group, Executive Director

The NEWIS external review process, consisting of the Technical Review Committee (TRC) and the Planning Advisory Committee (PAC), was designed to ensure the NEWIS study was guided by the highest quality of technical work and greatest accuracy of results, and that interested stakeholders had the opportunity to provide input to the NEWIS at key stages of the study. This external review process was intended to ensure that the NEWIS provides accurate, representative, and relevant results and information for New England. A total of six TRC meetings and eight PAC presentations were held throughout the NEWIS project.

The PAC is the regional forum for interested parties to provide input to ISO-NE concerning the assessment and development of the Regional System Plan (RSP) and the conduct of system enhancement and expansion studies.

The TRC was created specifically for the NEWIS and was designed and assembled in a manner consistent with recommendations of the Utility Wind Integration Group (UWIG) and the aggregate experience from previous wind integration studies. Collectively, the TRC provided expertise in all of the technical disciplines relevant to the study.

Table 1–3 is a chronological breakdown of all project milestones, including PAC and TRC meetings.

Table 1–3 NEWIS Milestones

Milestone/Meeting	Date	Description
PAC Review	12/17/2008	Project roll out
Release RFP	12/19/2008	N/A
Select Vendor	3/17/2009	GE & Enernex & AWS Truepower team was selected
Project Kickoff Meeting	4/7/2009	Reviewed overall task flowchart, TRC participation, discussed overall approach and requirements
TRC Kickoff Meeting	5/22/2009	Project overview, TRC Charter, Analytical Approach
Scenario Development	6/9/2009	Begin wind Scenario Development
Markets and Ops meeting	6/10/2009	Explain ISO-NE Market and Operations to Team GE
PAC Review	6/17/2009	Status update, present selected vendor, TRC, refined scope of work
TRC Meeting 2	7/1/2009	Review mesoscale assumptions, introduce TRC, project schedule
ISO Senior Management Review	8/4/2009	Update of project status; PowerPoint presentation covering workplan, scenarios, assumptions, and comparison with Governors' Study
PAC Review	8/19/2009	Present scenario framework and assumptions
TRC Meeting 3	10/20/2009	Scenario framework and assumptions partial queue and full queue defined
Task 2 Release & PAC Meeting	11/18/2009	Discuss Task 2 report, status update
TRC Meeting 4	12/9/2009	Review sites/scenarios, discuss transmission overlays, discuss interim statistical results and interim MAPS results
PAC Review	12/16/2009	Short recap of VAr management recommendations from Task 2
PAC Review	1/21/2010	Describe wind scenarios and transmission overlays
TRC Meeting 5	3/22/2010	Wind scenarios, transmission overlays
PAC Review	5/25/2010	Interim results, transmission/wind scenario pairings
TRC Meeting 6	8/5/2010	Final draft results
ISO Senior Management Review	10/22/2010	Final draft presentation
PAC Review	11/16/2010	Presentation of key findings and recommendations
Final Report	12/17/2010	Release final full report

2 Objectives and Technical Approach

2.1 Development of the New England Wind Resource Area Model

AWS Truepower (AWST) developed a mesoscale wind model for the NEWIS study area, referred to as the New England Wind Resource Area Model (NEWRAM). The development of NEWRAM is based on the work that AWST conducted as part of the Eastern Wind Integration and Transmission Study (EWITS),[29] for which AWST was engaged by the National Renewable Energy Laboratory (NREL) to develop the wind resource and wind power output data.[30] The resulting superset of simulated wind resource data is referred to as NREL's Eastern Wind Dataset and represents approximately 790 GW of potential future wind plant sites within the EWITS study area, shown in Figure 2–1. NREL's dataset includes almost 39 GW of potential wind resource within the New England region.

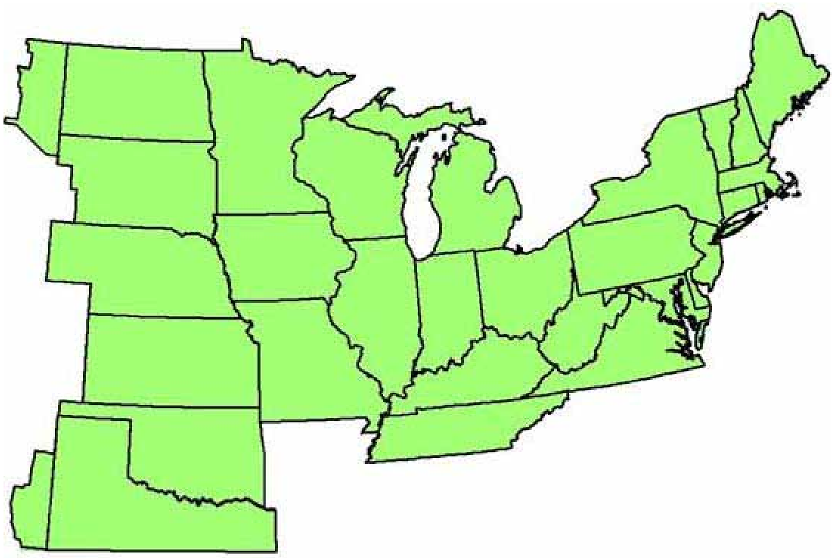

Figure 2–1 Eastern Wind Integration and Transmission Study (EWITS) study area. [from NREL report]

The ISO requested several alterations and additional features that are discussed in subsequent sections to provide more granularity and accuracy for the New England region. However, the

[29] Information about the EWITS study can be found at http://www.nrel.gov/wind/systemsintegration/ewits.html

[30] For detailed information on EWITS data development refer to: Brower, 2009: Development of Eastern Regional Wind Resource and Wind Plant Output Datasets. NREL/SR-550-46764. Golden, CO: NREL.

basis for NEWRAM is the New England regional subset of the Eastern Wind Dataset superset. As such, description of NEWRAM begins with an overview of the Eastern Wind Dataset modeling process.

AWST's work for EWITS consisted of the following five technical tasks:

1. Develop simulated 10-minute wind data for the regional wind resource using mesoscale modeling
2. Assist NREL with site selection
3. Convert the selected wind resources to time series wind generation
4. Simulate wind forecasts for the selected wind plants
5. Develop simulated one-minute plant output data for select time intervals.

2.1.1 NREL Eastern Wind Dataset

2.1.1.1 Mesoscale Model Testing

AWST began by running subsets of three years to total one year's worth of hourly simulations of two mesoscale models in a variety of configurations, and comparing the resulting diurnal and seasonal trends to coincident measurements observed at 10 tall tower sites throughout the study area. Based on comparison of the models, AWST selected the Mesoscale Atmospheric Simulation System (MASS),[31] which is a proprietary numerical weather prediction model developed by AWST's partner, MESO, Inc. MASS uses data from a variety of geophysical[32] and meteorological databases to simulate atmospheric conditions over a specified interval and geographical area. In the finally selected configuration, AWST used the NCEP/NCAR Global Reanalysis (NNGR) dataset as the initializing data source, with rawinsonde and surface data assimilated in the course of the simulations.

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[31] MASS is a simplified computational fluid dynamics (CFD) model that is able to simulate complex wind flows in areas where ground measurements are nonexistent, and is designed to generate a highly detailed and realistic representation of wind resource.

[32] Geophysical data include topography, land cover, vegetation greenness, sea-surface temperatures, soil temperatures, soil moisture. Elevation data are from the Shuttle Radar Topographical Mission 30 Arc-Second Data Set (SRTM30). Land cover data are from the satellite-based Moderate Resolution Imaging Spectro-radiometer (MODIS) data set. The nominal spacing of all geophysical data sets is 1 km.

2.1.1.2 Mesoscale Simulations

After selecting the model configuration, AWST conducted the mesoscale simulations of the historical climate for years 2004, 2005, and 2006[33] across the EWITS study area. Each year was run separately at a temporal and spatial resolution of 10-minutes and 2 km, respectively. For each 2 km cell, four files containing the following data were produced:

1. Surface pressure,
2. Temperature at 2 meters
3. Wind speed and direction, air density, and turbulent kinetic energy[34] (TKE) at a height of 80 meters
4. Wind speed and direction, air density, and TKE at a height of 100 meters

Data generated by the model constitute an instantaneous "snap-shot" of climatological conditions at each 10-minute time increment of the years simulated.

2.1.1.3 Selection of Sites – Exclusions and Wind Siting Assumptions

The Eastern Wind Dataset site selection process was developed to identify the smallest "near-contiguous" areas sufficient to support the desired rated capacity, while also both meeting specified exclusion criteria and exhibiting the highest possible capacity factor. To conduct the site screening, AWST used predicted mean wind speeds at 80 meters from their proprietary MesoMap®[35] to generate a net capacity factor map. AWST's MesoMap® system is a hybrid of MASS and a microscale wind flow model that is used to simulate weather conditions for a representative meteorological year over a region of interest with a spatial resolution of 200 meters. For MesoMap®, MASS randomly samples daily data from a 15-year period so that each

[33] The multi-year simulation period was selected to capture the effects of El Niño/Southern Oscillation (ENSO), which is a quasi-periodic climate pattern causing weather disturbances in North America. For the National Weather Center's archive of ENSO activity over the simulation period, see http://www.cpc.ncep.noaa.gov/products/expert_assessment/ENSO_DD_archive.shtml.

[34] Turbulent kinetic energy is meant to represent the smaller scale turbulent flows in the larger scale mean wind flows. Turbulent flow promotes mixing which increases average wind plant wind speeds, but also increases plant maintenance requirements.

[35] For detailed information on AWST's MesoMap® system, see: Brower et al, 2004: Mesoscale Modeling as a Tool for Wind Resource Assessment and Mapping. Proceedings of the 14th Conference on Applied Climatology, Boston, MA: American Meteorology Society, 7 pp.

month and season is represented equally, resulting in a non-contiguous hourly time series of wind and other weather variables. The results are summarized and input into the WindMap program, and then validated and adjusted (if necessary) with respect to wind measurements gathered from stations located in the region of interest. Data contained in the MesoMap® database include annual and monthly wind speed frequency distribution, diurnal wind speed distribution, and the directional distribution of the wind (i.e., wind rose[36]) associated with each 200-meter grid cell.

By using a GIS mapping process, exclusion criteria were developed and applied to the regional wind resource to account for land use restrictions and obtain a realistic representation of the sites most likely to be developed. Data from the United States Geological Survey (USGS) National Land Cover Database (NLCD)[37] and ESRI database[38] were utilized to map exclusion areas covering the following criteria:

Onshore Sites:

- Open Water
- 200 meter buffer of Developed Low Intensity
- 500 meter buffer of Developed Medium Intensity
- 500 meter buffer of Developed High Intensity
- Woody Wetlands
- Emergent Herbaceous Wetland
- Parks
- Parks Detailed
- Federal Lands (non – public)
- 10,000 ft buffer of small airports (all hub sizes)

[36] A wind rose is a diagram of both the percent of total time and mean wind speed from each azimuthal wind direction, usually measured in 22.5 degree increments. Sometimes percent of total estimated wind energy from each direction is also shown.

[37] NLCD is a 21-class land cover classification system applied consistently over the United States. The spatial resolution of the data is 30 meters. For more information see: http://www.mrlc.gov/nlcd.php.

[38] ESRI databases are geodatabases that serve data directly to web map server software developed by ESRI, called ArcGIS Internet Map Server. Mapped databases cover a broad range of information including land uses, demographical, and topographical data.

- 20,000ft buffer of large airports (medium and large hub sizes)
- Elimination of slopes greater than 20%

Offshore Sites:

- Sites must have a capacity factor of 32% or greater at 80 meters hub height
- At least 8 km from mainland for all states
- Water depths must be less than or equal to 30 meters

Onshore exclusion criteria were chosen in anticipation that the “best” onshore sites will be the ones developed first. The criteria were meant to steer site selection away from restrictive land uses and areas where wind development is either not viable or would be uneconomical. For instance, the increased technical challenge of installing turbines on extreme grades, coupled with the additional mechanical stress and fatigue that up flowing wind (a characteristic of the wind resource on steeper slopes) introduces on turbine components, makes these locations less desirable for wind development. Similarly, offshore exclusion criteria were selected to avoid potential barriers to development, and as such are designed to minimize visual impacts and represent the state of the art in industry standards concerning water depth. Offshore exclusion criteria concerning waves and currents were not included.

Using a floor capacity value of 22% for onshore wind power plants, sites with a local maximum capacity factor, at least 100 MW capacity and spacing no closer than 2 km to nearby sites were selected. AWST estimated a wind power density ranging from 8 MW/km2 to 20 MW/km2 based on the shape of each site. Due to the scarcity of sites in several states including Connecticut and Rhode Island, a separate site screening with a lower capacity factor threshold (approximately 13.5%) was conducted for those states. With the addition of these lower capacity sites, the result was a comprehensive set of more than 7,800 sites with a corresponding nameplate capacity of over 3,000 GW. NREL manually selected the final set of sites to ensure that a diverse set of scenarios could be developed for the Eastern Wind Dataset, with all states and regions well represented. NREL’s selection process was based on setting capacity factor thresholds for each state that reduced the total set to match target statewide capacities. A set of 1,326 sites with a range of rated capacities totaling over 580 GW was used as the final pool to select from in developing the Eastern Wind Dataset wind scenarios.

AWST used mean 80-meter wind speeds to identify potential offshore sites with an estimated net annual capacity factor of at least 32%. Due to the spatial consistency of the offshore wind resource, these sites were grouped into 20 MW blocks representing 4 km^2 each with a mean wind power density of 5 MW/km^2. A total of more than 10,000 blocks representing almost 209

GW of potential wind plants were identified. Table 2–1 shows the breakdown of onshore and offshore sites for the Eastern Wind Dataset wind plants located in New England.

Table 2–1 Potential New England sites used for Eastern Wind Dataset

	Onshore Sites		Offshore Sites	
State	Count	Total MW	Count	Total MW
Connecticut	7	919	84	1680
Maine	42	5863	64	1280
Massachusetts	19	2166	1006	20120
New Hampshire	21	2371	1	20
Rhode Island	7	1039	65	1300
Vermont	17	2019		
Total	113	14377	1220	24400

2.1.1.4 Wind Plant Modeling and Resource-to-Power Conversion

Once the sites were selected, AWST used their proprietary program SynOutput to convert the atmospheric time-series data to wind plant output. Expected mean wind speeds for each site were taken from MesoMap® and adjusted to the year of simulation with respect to AWST's historical dataset spanning years 1997 to 2007. The mesoscale time series associated with each site was then scaled to match the expected mean wind speeds. Further adjustments were made to each site's diurnal and seasonal wind characteristic trends according to their correlation with corresponding trends of coincident measurements collected at the 10 validation stations. These adjustments were used to correct model biases.

Power curves were then developed for IEC Turbine Classes 1, 2 and 3 based on a composite of utility-scale, commercially available wind turbines. IEC Class 1 and 2 turbines are assumed to have a hub height of 80 meters; IEC Class 3 turbines are assumed to have hub height of 100 meters. SynOutput then applied the power curve for each turbine class to the time-series data for both hub heights at each site, and selected the most appropriate power output based on its estimated annual mean speed[39].

The following operational considerations were factored into SynOutput to ensure realistic conversion of the simulated meteorological data to wind plant power output:

- Wake loss estimation utilizing siting assumptions in conjunction with the prevailing wind direction determined from the simulated data.
- A random factor related to the TKE was used to account for wind gusts not explicitly simulated by the mesoscale model. Otherwise the simulated wind power time-series are too smooth.
- A normally distributed turbine availability with a mean of 94.8% and a standard deviation of 2.3%
- Three percent electrical losses
- Effects of spatial averaging on the fluctuating wind power
- The cumulative impact of these considerations resulted in total power losses at most sites between 15% to 17%, and a range of losses at all sites of 12% to 20%.

The results of the mesoscale modeling, site selection process, and power conversion were annual 10-minute time-series wind power data associated with each potential wind site for the years of 2004, 2005 and 2006.

2.1.1.5 Wind Forecasting Development

Along with synthesizing wind data, AWST produced hourly forecasts for three different time horizons (next-day, six-hour, and four-hour) using their statistical forecast synthesis tool, SynForecast. The forecasts were intended to represent real forecasts generated by a state-of-the-art forecasting system for the years 2004, 2005, and 2006—the years of the simulated wind time-series. A typical state-of-the-art day-ahead forecast has a Mean Absolute Error (MAE) of 20%.[40]

[39] The selection of the appropriate IEC turbine class is actually based on both the turbulence intensity (TI) and the extreme 10-minute average wind speed with a 50 year recurrence (Vref) at hub height. However, standards allow a multiplier of 5 to estimate Vref from the mean speed. Turbulence intensity is the expected value (at 15 m/s) of the standard deviation of the 10-minute average wind speed divided by the 10-minute average wind speed. Since simulated wind speeds are instantaneous, TI values could not be determined by AWST. Therefore, only the mean wind speed for each site was used to determine turbine class.

[40] For more information on state-of-the-art forecasting refer to the NEWIS Task 2 report.

In order to develop a realistic forecast, AWST first developed a set of transition probabilities for simulated plant output data using a Markov chain process,[41] and then used these transition probabilities to produce forecasts for four wind plants for which NREL had provided concurrent output data. AWST then validated the forecasts using statistical comparisons of the output data, the forecasts, and the forecast errors to check for systematic biases. After corrections were made to the next-day and six-hour-ahead forecasts to ensure that their relative forecast errors were realistic, the forecasting methodology was determined to be satisfactory and was used to generate forecasts for all wind plants in the Eastern Wind Dataset.

2.1.2 Alterations to the Eastern Wind Dataset for NEWIS

Although first proposed by AWST, ISO decided that the New England subset of the Eastern Wind Dataset needed to be expanded and extended to meet the needs of NEWIS. Since the interaction of a region's wind resource and its power system is region-specific, narrowing the focus of a wind integration study to just New England allows for more tailoring of the study to suit its unique wind patterns, installed generation, transmission system, and load patterns. As stated by the North American Electric Reliability Corporation (NERC) Integration of Variable Generation Task Force (IVGTF)[42], "The degree to which wind matches demand may differ widely in different geographic areas and at different times of the year. Therefore, it is not possible to generalize the pattern of wind generation across the NERC region."[43] IVGTF further notes that calculating the ELCC of wind power requires careful accounting of the correlation of hourly variable generation and hourly demand, and that "this data is needed for variable generation plants in the specific geographic regions being studied."[44]

In general, the vast footprint of the Eastern Wind Dataset precludes significant consideration of the specific characteristics of the regional wind resource, land use patterns, and power system. For example, in contrast to the expansive wind resources located in the Great Plains, the

[41] A Markov chain represents a random process where the probability distribution of some future state depends only on the current state. In its application to wind forecasting, the stochastic nature of wind is represented so that the future distribution of future wind speeds (or wind power output) depends only on the current wind speed (or power output).

[42] The IVGTF was created by NERC's Planning and Operating Committees in December 2007 to raise industry awareness/understanding of the characteristics of variable generation and the challenges associated with large-scale integration of variable generation.

[43] IVGTF report, p. 15

[44] IVGTF report, p. 38

majority of onshore wind resources within New England are located in mountainous pockets, resulting in smaller developable sites. Differences such as these render some site selection assumptions used for EWITS less relevant for NEWIS, and also pose the need for a few different land use exclusions. Additionally, the regional tendency towards smaller wind sites in New England presents a need for greater flexibility in site selection for NEWIS. New England's interties with the New York and the Canadian Maritime Provinces, all of which possess significant native potential wind resource, warrant a more granular examination of the external impacts of wind development from these windy neighbors on the regional bulk power system. Ultimately, incorporation of the aforementioned unique regional characteristics into NEWRAM would facilitate the creation of more insightful wind scenarios, thereby helping to identify and evaluate operational issues imposed by significant wind penetrations on New England's bulk power system.

In order to expand the dataset for NEWIS, the New England subset of the more comprehensive 3,000 GW site set was employed rather than those solely from the final 580 GW Eastern Wind Dataset. Again, the larger set was that from which NREL hand selected the final 580 GW dataset primarily by using a list of projects sorted by capacity factor to meet a capacity target for each state. Use of the larger set added 164 more onshore sites, and more than doubled the potential onshore wind resources available for the NEWIS from approximately 14.4 GW to almost 35.6 GW. No offshore sites were eliminated during NREL's final hand selection process, so no additional offshore sites are contained within the larger set. Table 2–2 lists the additional sites included that were added from the larger set to the Eastern Wind Dataset.

Table 2–2 Additional Sites Included in NEWIS Dataset

	Onshore Sites	
State	Count	Total MW
Connecticut	25	3679.2
Maine	107	13623.9
Massachusetts	5	683.6
New Hampshire	5	585.2
Rhode Island	4	478.9
Vermont	18	2134.8
Total	164	21185.3

As a starting point in the development of realistic wind scenarios, it was deemed necessary that the NEWRAM include wind projects already existing in New England, as well as those projects that have initiated the development process as demonstrated by their presence in the ISO-NE Generator Interconnection Queue.[45] It was therefore important that Queue sites be included in the NEWRAM irrespective of exclusions. As of April 17, 2009, 4,169 MW of wind projects were in the Queue, 1,140 MW of which had received a determination of approval based on information reviewed by ISO during the System Impact Study (SIS)/I.3.9 process.[46]

Upon review, it was determined that the Queue sites were either coincident or adjacent and sufficiently close to the sites in the expanded set, and therefore, the expanded set was adequately representative of the regional wind resource. Table 2–3 is a breakdown of wind projects in the Queue that were included in the NEWRAM.

[45] The ISO-NE Generator Interconnection Queue is used to manage generator Interconnection Requests submitted for generators larger than 5 MW in capacity. There are three processes involved in interconnecting a generator: an interconnection process, a market process, and an I.3.9 approval process. Completion of the interconnection process results in an Interconnection Agreement. A generator's satisfaction of the requirements of the market process results in a Market Participant Service Agreement outlining the generator's participation in the Markets for the sale of energy, capacity, and/or ancillary services. Satisfactory completion of the I.3.9 process leads to the ISO granting permission to the generator to operate when interconnected to the regional system.

[46] A SIS is a peer review process to ensure that a generator or transmission project has no significant adverse impact on reliability. A determination of approval under Section I.3.9 of the ISO Tariff is a recommendation that a Queue project will not have significant adverse impact on transmission facilities or the system of another Market Participant.

Table 2–3 Breakdown of wind projects in the ISO-NE Queue as of April 17, 2009

	Onshore Sites		Offshore Sites	
State	Count	Total MW	Count	Total MW
ME - SIS/I.3.9 Complete	6	429	0	0
SIS/I.3.9 Pending	22	2252	0	0
MA - SIS/I.3.9 Complete	2	44	1	460
SIS/I.3.9 Pending	1	15	0	0
NH - SIS/I.3.9 Complete	2	136	0	0
SIS/I.3.9 Pending	3	264	0	0
VT - SIS/I.3.9 Complete	2	71	0	0
SIS/I.3.9 Pending	3	138	0	0
RI - SIS/I.3.9 Complete	0	0	0	0
SIS/I.3.9 Pending	0	0	1	360
CT - SIS/I.3.9 Complete	0	0	0	0
SIS/I.3.9 Pending	0	0	0	0
Total	41	3349	2	820

2.1.2.1 *Additional Exclusions*

At the request of the ISO, additional exclusions specifically suited to the NEWRAM were added to the Eastern Wind Dataset screening process. Some, like the buffer around two regional recreation trails, are more restrictive than the Eastern Wind Dataset; others like the lower class wind speed exclusion are more permissive than the Eastern Wind Dataset. The requested exclusions include the following:

Onshore Sites:

- Class 2 or lower wind speed (at 80m)
- Within a buffer of 4 miles for the Appalachian Trail and Long Trail
- Elevations over 3,000 feet – restricting to lower elevations:
    - Reduces blade icing problems
    - Reduces installation costs
    - Reduces impact on viewshed
- Screen out Martha’s Vineyard, MA and Nantucket, MA

Offshore Sites:

- Class 4 or lower wind speed (at 80 meters)
- Sites must be at least:
    - 8 km from mainland for Maine
    - Outside of state waters for Massachusetts, Rhode Island, and New Hampshire

After incorporating the exclusions, it was determined that there was a pool of potential sites sufficient to begin development of the NEWIS wind scenarios.

2.1.2.2 Expanded Validation

Additional wind speed validation was performed using four measurement stations in New England and four in New York. Based on a review comparing modeled versus measured wind data, no changes to the data resulted from the expanded validation.

Expanded validation of power output data was conducted with respect to nearest of five operational wind plants in New England for which there is 10-minute plant output data. Two of the five operational plants provided data covering the entire 3-year period simulation, and a third plant provided approximately 8 months of coincident data. Two plants provided data more recent than the simulation period. Regardless of the duration of coincident data, a comparison of the diurnal and seasonal trends between measured and simulated data were evaluated. Based on the results of the power validation, the power plant data was left intact and utilized for the final development of the NEWIS wind scenarios.

See Appendix A for AWST's tables and figures associated with the extended wind speed and power output validation.

2.1.2.3 Modeling of Wind in Neighboring Systems

Wind power production within NYISO and PJM was projected to develop in parallel to native wind development. Therefore, wind power's contribution to the total energy demands of both the NYISO and PJM were assumed to match those of wind's contribution in New England. For example, if a regional wind scenario was developed to meet 20% of the New England's total energy demand, the assumed wind penetrations were assumed to meet the same energy requirements in both NYISO and PJM. Wind plant siting and transmission required within these balancing areas was not considered for the NEWIS.

A dataset similar to the Eastern Wind Dataset was developed for the Maritime Canadian Provinces of New Brunswick, Nova Scotia, and Prince Edward Island. Table 2–4 shows a total of 76 potential onshore sites totaling a nameplate capacity of almost 10.4 GW, and a total of 39 offshore sites representing almost 4.8 GW nameplate that were identified. Since the onshore wind resource synthesized for the Maritimes exhibited a high capacity factor, no offshore sites were selected for the Maritimes wind fleet modeled for the NEWIS Maritime scenarios.

Table 2–4 Sites added for Canadian Maritime Provinces

	Onshore Sites		Offshore Sites	
State	Count	Total MW	Count	Total MW
New Brunswick	10	948.1	8	906.6
Prince Edward Island	12	2489.3	9	1195.4
Nova Scotia	54	6931.8	22	2660
Total	76	10369.2	39	4762

In summary, the NEWIS dataset differs from the New England region of the Eastern Wind Dataset in the following ways:

1. The Eastern Wind Dataset model was expanded to cover the Canadian Maritime Provinces of New Brunswick, Prince Edward Island, and Nova Scotia.
2. Additional wind speed and power output validation was performed using data collected from measurement stations and existing wind plants located in New England and New York.
3. AWST provided an expanded dataset (164 additional onshore sites totaling more than 21 GW of nameplate capacity when compared to New England subset of Eastern Wind Dataset) that included existing and proposed wind sites listed on the ISO-NE Generator Interconnection Queue as of April 17, 2009.
4. AWST ensured all Queue sites were scaled commensurate with their proposed installed capacity.
5. Additional exclusions were added to the site selection process.
6. Alterations to site size restrictions were made in order to allow smaller sites.

2.2 Load Data

2.2.1 Source

The ISO develops its plans to address needs in the regional transmission system through an open stakeholder process. Each year these needs are considered over a planning horizon of 10 years as part of the planning process conducted for ISO's Regional System Plan (RSP). Based in part on stakeholder input, the ISO develops plans to meet system needs cost effectively and without degrading the performance of the New England system, the NPCC region, or the remainder of the Eastern Interconnection.[47] In order to aid in the RSP process 13 subsets of the electric power system, called RSP-subareas, have been established to assist in modeling and planning electricity resources. These subareas reflect a simplified model of major transmission bottlenecks of the system, called interfaces, which are physical limitations of the flow of power due to a variety of system conditions (e.g. thermal transfer limit).

The load data used in the hourly production cost simulation analysis portion of the NEWIS comes from the ISO-NE pricing nodes (aka. p-nodes). P-nodes represent locations on the transmission system where generators inject power into the system or where loads withdraw power from the system. Each p-node is related to one or more electrical buses on the power grid.[48] A bus is a specific component of the transmission system at which generators, loads or the transmission system are connected. Therefore the more than 900 p-nodes that are defined electrically are also associated with physical locations within New England.

There is a direct mapping between RSP-subareas and p-nodes such that each p-node exists within one and only one of the 13 RSP-subareas. Similar to p-nodes, RSP-subareas also are associated with physical regions though the true definitions are also based on the electrical network. For the NEWIS, the load data from p-nodes has been aggregated into the respective RSP-subareas.[49] Figure 2–2 is a simplified model of the system that shows a geographical description of the ISO-NE RSP-subareas and three external control areas.

One minute average total ISO New England load data comes from the Plant Information (PI) data historian, which extracts data from the Energy Management System used for power system control.

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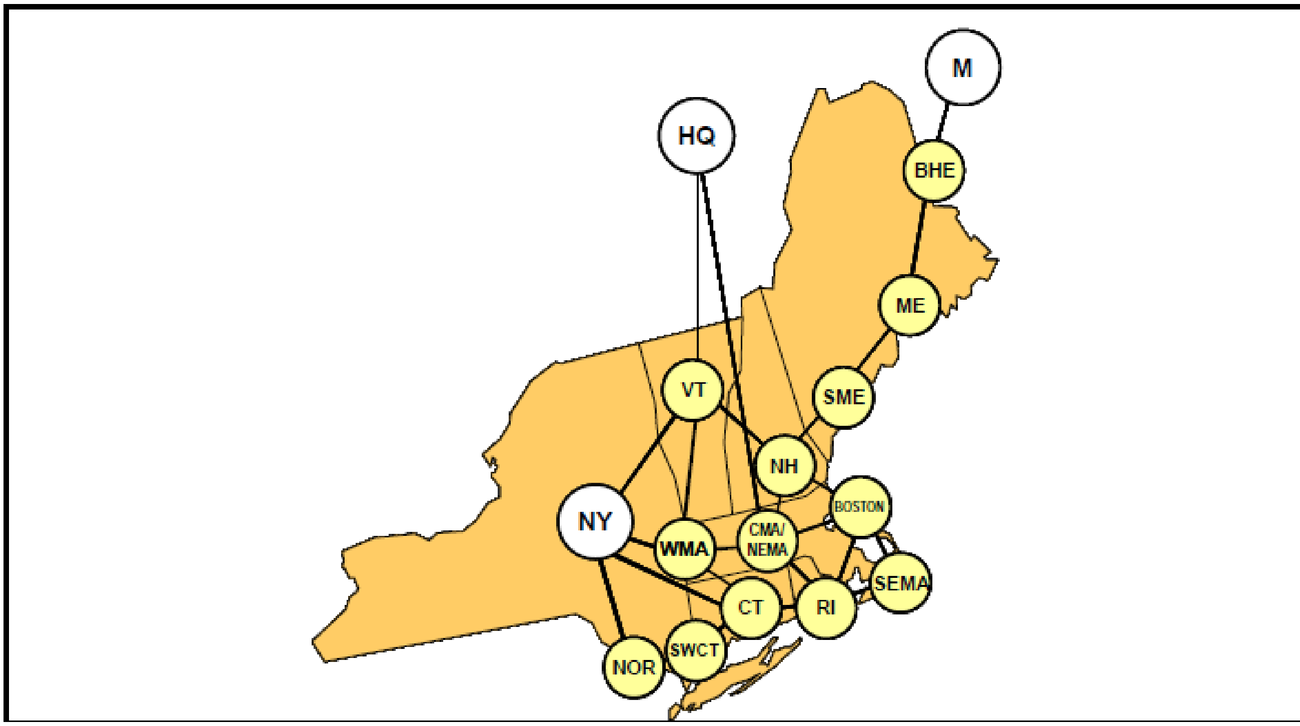
[47] The Eastern Interconnection is the network of interconnected transmission and distribution infrastructure that operates synchronously, and covers the area east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas (ERCOT) and Quebec.

[48] More information regarding p-nodes can be found in ISO-NE Manual M-11 "ISO New England Manual for Market Operations" available at: http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

[49] A table of the mapping of p-nodes to RSP subareas can be found at, for example http://www.iso-ne.com/stlmnts/stlmnt_mod_info/2006/index.html
P-node tables are updated a few times per year as new generators and loads come into the system.



Subarea Designation	Region or State	Subarea or Control Area Designation	Region or State
BHE	Northeastern Maine	**WMA**	Western Massachusetts
ME	Western and central Maine/ Saco Valley, New Hampshire	**SEMA**	Southeastern Massachusetts/ Newport, Rhode Island
SME	Southeastern Maine	**RI**	Rhode Island/bordering MA
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine	**CT**	Northern and eastern Connecticut
VT	Vermont/southwestern New Hampshire	**SWCT**	Southwestern Connecticut
BOSTON	Greater Boston, including the North Shore	**NOR**	Norwalk/Stamford, Connecticut
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts	**M, NY, and HQ**	Maritimes, New York, and Hydro-Québec external control areas

Figure 2–2 RSP-subareas Geographical Representation Source RSP06

As mentioned, RSP-subareas are defined by the external and internal interfaces. Figure 2–3 shows a graphical representation of the 13 RSP-subareas and the interfaces between them. Interfaces are used to approximately represent the maximum power flow from one region or RSP-subarea to another. An interface can be one transmission element (transmission line, transformer, etc.) or a group of transmission elements. There are two different characterizations of interfaces: closed and open interfaces. A closed interface forms a cut-set and will cause separation of two regions if the group of transmission elements that forms this interface is removed from service (by, for example, opening the connecting circuit breakers at a transmission line substation). For example, if the ties across the BOSTON Import interface were cut, the RSP-subarea BOSTON would form an electrical island, separate from the rest of the ISO-NE system. In the case of a closed interface the maximum power transfer limits are relatively constant and known. An open interface does not form a cut-set and therefore will not completely separate two portions of the system and the maximum power limits are less constant and more approximate. For instance the North-South interface is an open interface since the ties may still be connected between the VT RSP-subarea and the external NY system which is also connected to the WMA, CT, and NOR RSP-subareas that are connected to the rest of the ISO-NE system. Though they are shown in Figure 2–3, High Voltage Direct Current (HVDC) lines (i.e. HQ to CMA/NEMA Phase II and NY to CT CSC) are not included in the interface definitions since due to their controllability they may be used independently of the underlying AC transmission system.

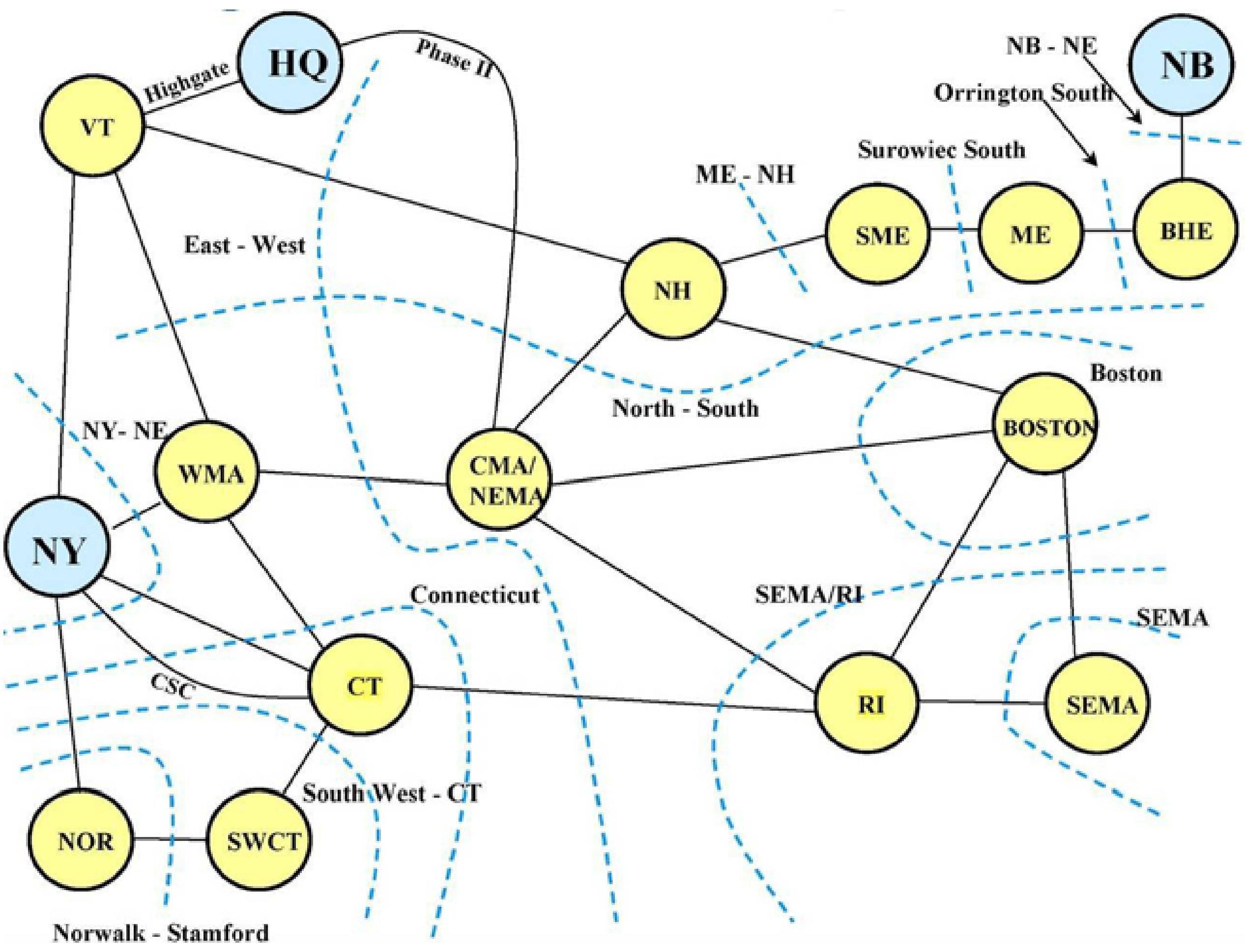


Figure 2–3 RSP-subareas Graphical Representation showing Interfaces Source rsp09

The historical loads for each RSP-subarea for all hours of the years 2004, 2005, and 2006 were time-synchronized with the wind power data synthesized in the mesoscale model development.

In this manner the net load (i.e. load minus wind) could be used for the dispatch of the more conventional (i.e. dispatchable) resources on the system. The net load concept is critical to determining the operating impacts that wind generation may have for two reasons 1) power produced by wind is essentially used as available (i.e. wind is a non-dispatchable resource) and 2) the variability that must be matched by the fleet of dispatchable resources is the combination of the variability introduced by wind and by load which are somewhat correlated. Since the variability of wind and the variability of load are somewhat correlated (i.e. neither perfectly correlated or anti-correlated nor completely uncorrelated) they cannot be analyzed independently.[50]

2.2.2 Extrapolation Methodology and Effects

One difficulty in this study has been to determine the best manner in which to extrapolate the 2004 thru 2006 loads out to what they might be during the timeframe under study (i.e. the approximate year of 2020). A complicating factor is that whatever extrapolation methodology employed should preserve the shape of the loads in order to preserve the "net load" concept where the variability on the system is determined by subtracting the time-synchronous wind generation from native load on the system. This net load concept allows for a more complete picture of how the dispatchable resources on the system will be utilized, since the wind generation will essentially be an "as available" resource (due to its low operational cost and policy incentives to maximize wind derived energy) and this as available resource shares some (but not all) of the originating phenomena that drive the load: over most timescales, load and wind are only loosely correlated (at best).

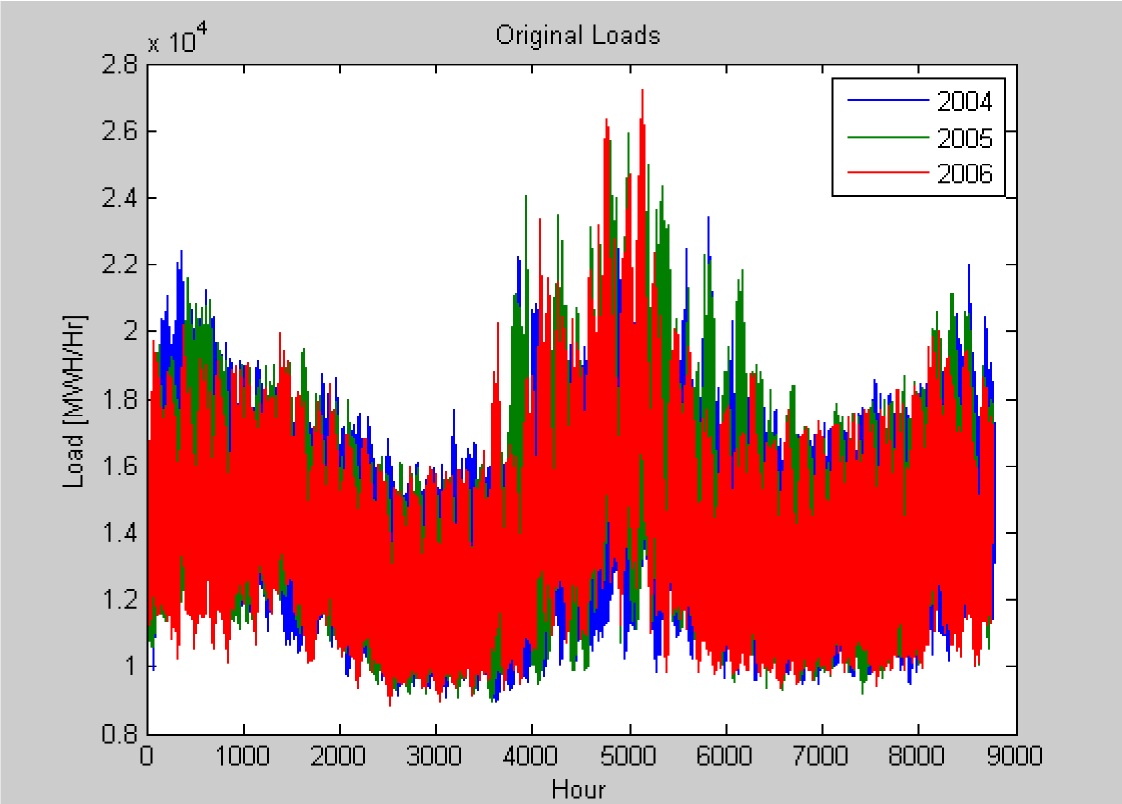
After initial attempts at developing a more complex extrapolation technique, simple peak ratio scaling was selected as the preferred method of extrapolation. In peak ratio scaling, the peak load hour is multiplied by a value to bring it to the expected target peak (in this case 31.5 GW). All other hours in the year are multiplied by this same value. This process was used for each of the years investigated (2004, 2005, and 2006). Table 2–5 shows each year's peak load and the peak load ratio used to multiply all the loads for each year.

[50] A further description of the net load concept and its criticality to determining operational impacts can be found in the report Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements by GE Energy Applications and Systems Engineering.

Table 2–5 Load Extrapolation using Peak Load Methodology

Year	Peak Load	31.5 GW/Peak Load
2004	23.4 GW	1.344
2005	25.9 GW	1.214
2006	27.2 GW	1.158

All forms of load extrapolation possess certain advantages and disadvantages: though peak load scaling does not allow precise matching for specific energy targets, peak load scaling is straightforward and completely preserves the load shape which also has the effect of growing the hour-to-hour load changes in a predictable and reasonable fashion. Peak scaling ratio is a common method for load extrapolation both in general and for wind integration studies. The main effect of peak load scaling is that the amount of annual energy for the extrapolated load varies somewhat between the years since the load shapes are different for each of the three years. Figure 2–4 shows the unscaled loads above and the scaled loads below.



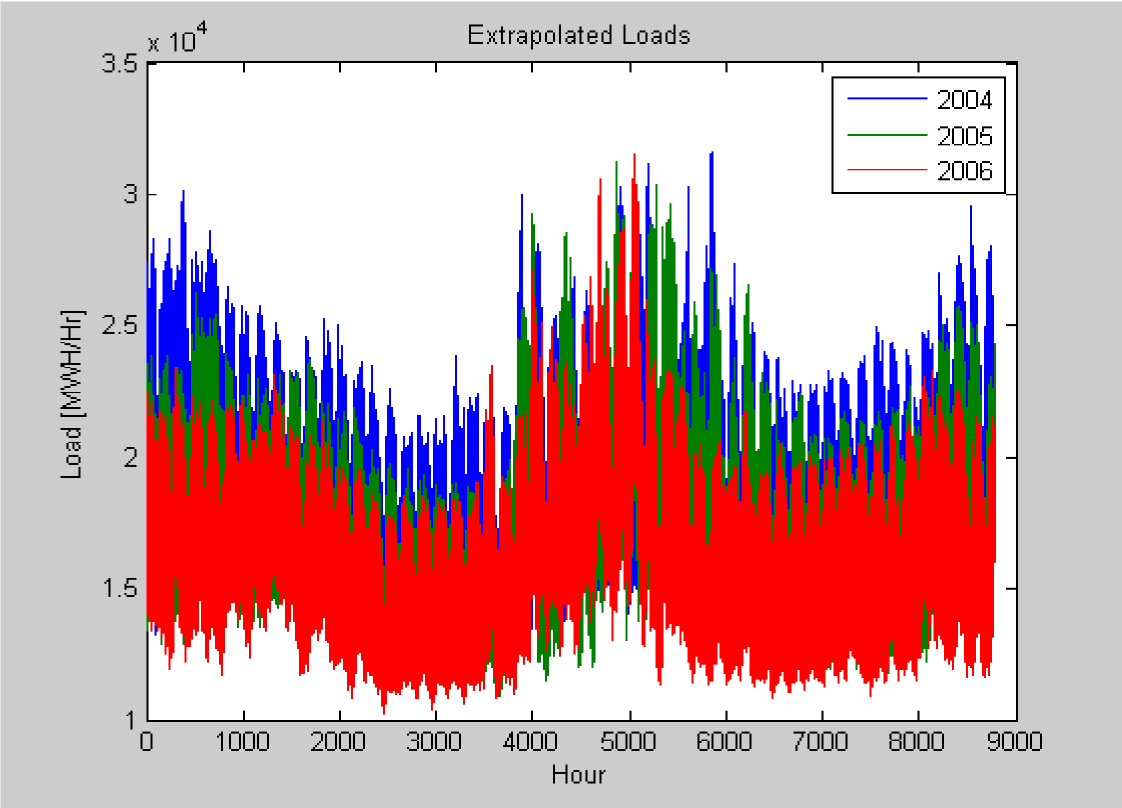


Figure 2–4 Original and Extrapolated Loads

As can be observed in the top half of Figure 2–4, the original load shapes are different from each other. For instance, the peak load hour in 2004 occurs much later in the year (approximately hour 5800) than it does for the peak hours in 2005 and 2006 (both of which occur at about hour 5200). The peak loads for 2005 and 2006 are also much closer in magnitude (25.9 GW and 27.2 GW) as compared to the peak load of 2004 (23.4 GW). Also of note is that there are higher loads in the winter of 2004 than there are in the years of 2005 and 2006. These differences are somewhat magnified by the peak load scaling, as can be seen in the bottom half of Figure 2–4. Also, since the peak load ratio is larger for 2004 than it is for either 2005 or 2006, all loads in 2004 are multiplied by a larger value for extrapolation. This increases the magnitude of the extrapolated loads for the 2004 loadshape and its effect is particularly visible on the loads during the shoulder months. Also, since the loads in the winter of 2004 are larger than the loads in the winter of 2005 or 2006, the extrapolated loads during the winter of 2004 are significantly higher than those of either 2005 or 2006. Some of the global effects of these differences include the facts that there is a larger annual energy associated with the extrapolated 2004 loadshape than for the 2005 or 2006 loadshapes: 174.42 TWH (2004), 160.75 TWH (2005), and 149.24 TWH (2006); and that there are some larger hour-to-hour changes in the loads for the 2004 and 2005 extrapolated loadshapes as compared to the 2006 extrapolated loadshape.

2.3 Overview of Study Scenarios

2.3.1 Introduction

All of the NEWIS wind scenarios are set to represent approximately the 2020 timeframe. In addition to the base case assumptions, there are five main categories of wind build-out scenarios representing successively greater penetrations of wind. The scenarios are categorized either by the aggregate installed nameplate capacity of wind power or the simulated wind fleet’s contribution to the region’s forecasted annual energy demand. Values used for wind energy generated by each scenario are averages of the three years simulated via mesoscale modeling. Values of annual energy demand for the region and individual states are also averages for the three extrapolated load years used in the simulations and individual load supplied by energy efficiencies that has been bid into the FCM.

These categories of wind build-out scenarios include:

- Partial Queue Build-out
    - Represents 1.14 GW of installed wind capacity
    - Approximately 2.5% of the forecasted annual energy demand
- Full Queue Build-out
    - Represents 4.17 GW of installed wind capacity

- Approximately 9% of the forecasted annual energy demand

- Medium wind penetration
  - Represents between 6.13 GW and 7.25 GW of installed wind capacity
  - Approximately 14% of the forecasted annual energy demand
- High wind penetration
  - Represents between 8.29 GW and 10.24 GW of installed wind capacity
  - Approximately 20% of the forecasted annual energy demand
- Extra-high wind penetration
  - Represents between 9.7 GW (for offshore) or 12 GW (for onshore) of installed wind capacity
  - Approximately 24% of the forecasted annual energy demand

Of the five categories, the Partial Queue and Full Queue build-outs are comprised of projects that were in the ISO Generator Interconnection Queue as of April 17, 2009, and the queue lists the proposed point of interconnection for each project. All of the build-outs with greater wind penetration consist of wind plants strategically chosen and added to the Full Queue site portfolio, until either the desired aggregate nameplate capacity or the desired energy contribution of the resulting wind fleet was satisfied. A range of wind plant scenarios was developed to represent what the New England system might look like with varying levels of wind penetration, and to represent different spatial patterns of wind development that could occur, including wind development in the Canadian Maritime Provinces. The objective of scenario development was to enable a detailed evaluation of the operational impacts of incremental wind generation variability and uncertainty on New England’s bulk electric power system, including the incremental impact contributed by the spatial diversity of wind plants. The NEWIS was not intended to identify real or preferred wind integration scenarios.

In order to represent the impacts of wind portfolio diversity, five layout alternatives were developed for the medium and high wind penetration scenarios, i.e. the 14% energy and 20% energy scenarios. Two of these layout alternatives were also used for the extra-high wind penetration scenario. A description of the five layout alternatives developed for each energy target follows:

1. Best Sites Onshore – This alternative includes the onshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative’s wind fleet is comprised

predominantly of wind plants in Maine and therefore it exhibits low geographic diversity.

2. Best Sites Offshore – This alternative includes the offshore sites with the highest capacity factor needed to satisfy the desired regional energy or installed capacity component provided by wind power. This alternative features the highest overall capacity factor of each energy/capacity scenario set, but also a low geographic diversity. However, the steadier offshore wind resource features a higher correlation with load than onshore-based alternatives.

3. Balance Case (aka. Best Sites) – This alternative is a hybrid of the best onshore and offshore sites, and as such exhibits a high geographic diversity, including a good diversity by state. The offshore component of the wind fleet is divided equally between the states of Massachusetts, Rhode Island, and Maine (this is also the only alternative that includes offshore sites located in Maine). Due to a naming convention change during the course of the NEWIS, this layout alternative may be found listed in this report as either the “Balance Case” or the “Best Sites”.

4. Best Sites by State – This alternative likely represents the most spatially diverse native wind fleet, and is comprised of wind plants exhibiting the highest capacity factor within each state to meet that state’s contribution of the desired energy goal. For example, in the 20% energy scenario, each state’s wind fleet was built out in an attempt to meet 20% of the state’s projected annual energy demand so that the overall target of 20% of projected annual energy for New England was satisfied. This alternative enables the investigation of the effects of high diversity and wind power development close to New England’s load centers. It should be noted that since the Full Queue contained a disproportionately high capacity of wind projects located in Maine, the aggregate energy produced from these plants contributes approximately 58% of this state’s forecasted annual energy demand. This meant that the energy contribution of each of the other states was adjusted (percentage-wise) so that the regional wind fleet would produce the overall desired contribution to the forecasted regional energy demand.

5. Best Sites Maritimes – In addition to the Full Queue sites located within New England, this alternative is made up of extra-regional wind plants in the Canadian Maritimes Provinces sufficient to satisfy the desired New England region’s wind energy or installed capacity. No considerations were made regarding transmission upgrades required to deliver the hypothetical wind power to New England. Wind resources in the Maritimes exhibit a high geographic diversity and an overall

capacity factor approaching that of New England's offshore resource. Considering the wind plants in the Full Queue, this alternative features the greatest geographic diversity. Also, given the longitudinal distance of the Maritimes from much of New England, the effects of integrating wind in the presence of time zone shifts could be highlighted.

Table 2–6 below is the complete matrix of scenarios developed for the NEWIS analyses.

Table 2–6 Scenarios Evaluated for the NEWIS

Scenario #	Year	Wind Scenario	Transmission Model	Wind Penetration	Wind Type/Location
1	2020	24% Energy_Best Sites Onshore	Copper Sheet (8GW)	12GW	Queue (4GW) + Best Sites (CV + CF) Onshore
2	2020	24% Energy_Best Sites Offshore	Copper Sheet (8GW)	9.9GW	Queue (4GW) + Best Sites (CV + CF) Offshore
3	2020	24% Energy_Best Sites Onshore	8GW Trans. Overlay	12GW	Queue (4GW) + Best Sites (CV + CF) Onshore
4	2020	24% Energy_Best Sites Offshore	8GW Trans. Overlay	9.9GW	Queue (4GW) + Best Sites (CV + CF) Offshore
5	2020	20% Energy_Best Sites Onshore	Copper Sheet (4GW)	9.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
6	2020	20% Energy_Best Sites Offshore	Copper Sheet (4GW)	8.3GW	Queue (4GW) + remainder Offshore (CV + CF)
7	2020	20% Energy_Best Sites Maritimes	Copper Sheet (4GW)	9GW	Queue (4GW) + Best Sites Maritimes
8	2020	20% Energy_ Balance Case	Copper Sheet (4GW)	8.8GW	Queue (4GW) + Best Sites (CV + CF) Offshore
9	2020	20% Energy_Best Sites by State	Copper Sheet (4GW)	10.2GW	Queue (4GW) + Best Sites (CV + CF) by State
10	2020	20% Energy_Best Sites Onshore	4GW Trans. Overlay	9.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
11	2020	20% Energy_Best Sites Offshore	4GW Trans. Overlay	8.3GW	Queue (4GW) + remainder Offshore (CV + CF)
12	2020	20% Energy_Best Sites Maritimes	4GW Trans. Overlay	9GW	Queue (4GW) + Best Sites Maritimes
13	2020	20% Energy_ Balance Case	4GW Trans. Overlay	8.8GW	Queue (4GW) + Best Sites (CV + CF) Offshore
14	2020	20% Energy_Best Sites by State	4GW Trans. Overlay	10.2GW	Queue (4GW) + Best Sites (CV + CF) by State
15	2020	14% Energy_Best Sites Onshore	Copper Sheet (2GW)	6.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
16	2020	14% Energy_Best Sites Offshore	Copper Sheet (2GW)	6.1GW	Queue (4GW) + remainder Offshore (CV + CF)
17	2020	14% Energy_Best Sites Maritimes	Copper Sheet (2GW)	6.4GW	Queue (4GW) + Best Sites Maritimes
18	2020	14% Energy_ Balance Case	Copper Sheet (2GW)	6.3GW	Queue (4GW) + Best Sites (CV + CF) Offshore
19	2020	14% Energy_Best Sites by State	Copper Sheet (2GW)	7.3GW	Queue (4GW) + Best Sites (CV + CF) by State
20	2020	14% Energy_Best Sites Onshore	2GW Trans. Overlay	6.8GW	Queue (4GW) + Best Sites (CV + CF) Onshore
21	2020	14% Energy_Best Sites Offshore	2GW Trans. Overlay	6.1GW	Queue (4GW) + remainder Offshore (CV + CF)
22	2020	14% Energy_Best Sites Maritimes	2GW Trans. Overlay	6.4GW	Queue (4GW) + Best Sites Maritimes
23	2020	14% Energy_Balance Case	2GW Trans. Overlay	6.3GW	Queue (4GW) + Best Sites (CV + CF) Offshore
24	2020	14% Energy_Best Sites by State	2GW Trans. Overlay	7.3GW	Queue (4GW) + Best Sites (CV + CF) by State
25	2020	9% Energy_Queue	Copper Sheet (2GW)	4.2GW	Queue (4GW)
26	2020	9% Energy_Queue	2GW Trans. Overlay	4.2GW	Queue (4GW)
27	2020	2.5% Energy_Commercial_SIS_1.3.9	Copper Sheet (2019 NPCC)	1.1GW	SIS & I39 Queue
28	2020	2.5% Energy_Commercial_SIS_1.3.9	2019 NPCC Case	1.1GW	SIS & I39 Queue

The lower penetration scenario types were used as building blocks in the development of higher penetration counterpart, e.g. the partial queue is a subset of the full queue, the full queue is a subset of all higher penetration scenarios, the 14% best onshore case is a subset of the 20% best onshore scenario, which in turn is a subset of the 12 GW best onshore scenario. Again, the Full Queue sites (totaling 4.17 GW in installed nameplate capacity) are a subset of each of the medium and higher penetration scenarios, and because these scenarios all have the Full Queue sites in common, the effects of varying spatial diversities of the different wind fleets should be more noticeable as the overall wind penetration increases. It was decided early in the project that due to time and scope constraints that the overlays developed for the Governors' study would be used in the NEWIS. For more information regarding the overlays see section 2.3.9.3.

Upon developing the scenarios and running copper sheet[51] analyses, it was found that the selected wind fleets exhibited higher than expected capacity factors, and that energy targets could be met with a reduced fleet of wind power plants.

2.3.2 Base Case – The System without Wind

The base case scenario is the New England bulk power system without wind power. Therefore, the base case assumptions are common to all the wind build-out scenarios. Since the historic years used to simulate system load for NEWIS date back to when there was only a negligible amount of wind power installed on the system, the base case was used to calibrate the system model.

Without wind, many of the assumptions made about the balance of the bulk regional power system are similar to those in the Governor's Study. For all the wind scenarios, system load characteristics include a regional forecasted 50/50 hourly summer peak load[52] assumed to be 31,500 MW, and a regional Installed Capacity Requirement (ICR)[53] of 35,100 MW. This forecasted ICR is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for New England and to maintain sufficient reserve capacity to meet reliability standards, which are defined for the New England Balancing Authority Area of disconnecting non-interruptible customers (a Loss of Load Expectation or "LOLE") no more than once every ten years (an LOLE of 0.1 days per year). [54]

The base case represents many assumptions concerning the supply-side portfolio of the bulk power system. Just as has historically been the case, the power system before wind is comprised almost exclusively of a fleet of conventional generation, which was expanded to meet the aforementioned future capacity requirement. Figures 2-5 and 2-6 show the capacity and energy,

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[51] In a "copper sheet" analysis limitations on the flow of electrical power are governed only by the network impedances: transfer limits (whether thermal, voltage, or stability) are removed in order to determine the nature of the underlying flow of power. This analysis is useful in determining where increasing transfer capability would be especially useful by reducing or eliminating congestion

[52] The term 50/50 hourly peak load refers to a forecast scenario in which there is a 50 percent chance that the actual hourly loads will be greater than the forecasted load, and a 50 percent chance that the forecasted hourly loads will be.

[53] Installed Capacity Requirement (ICR) is the amount of installed resources (capacity) needed to meet ISO-NE's Resource Adequacy Criterion. In this case, it is the ICR to meet the estimated 50/50 hourly peak load for the simulation timeframe.

[54] For more on ICR see: http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2009/index.html

respectively, of the generation in the New England System. In order to realistically model the base case, conventional generators added beyond those already existing on the system are those that have participated in the 2012/2013 Forward Capacity Auction, and have submitted interconnection requests within the ISO Generation Queue. Almost all of the conventional generation added is natural gas-fired thermal units.[55] Base fuel prices are those predicted by the Energy Information Agency (EIA) for the year 2020.

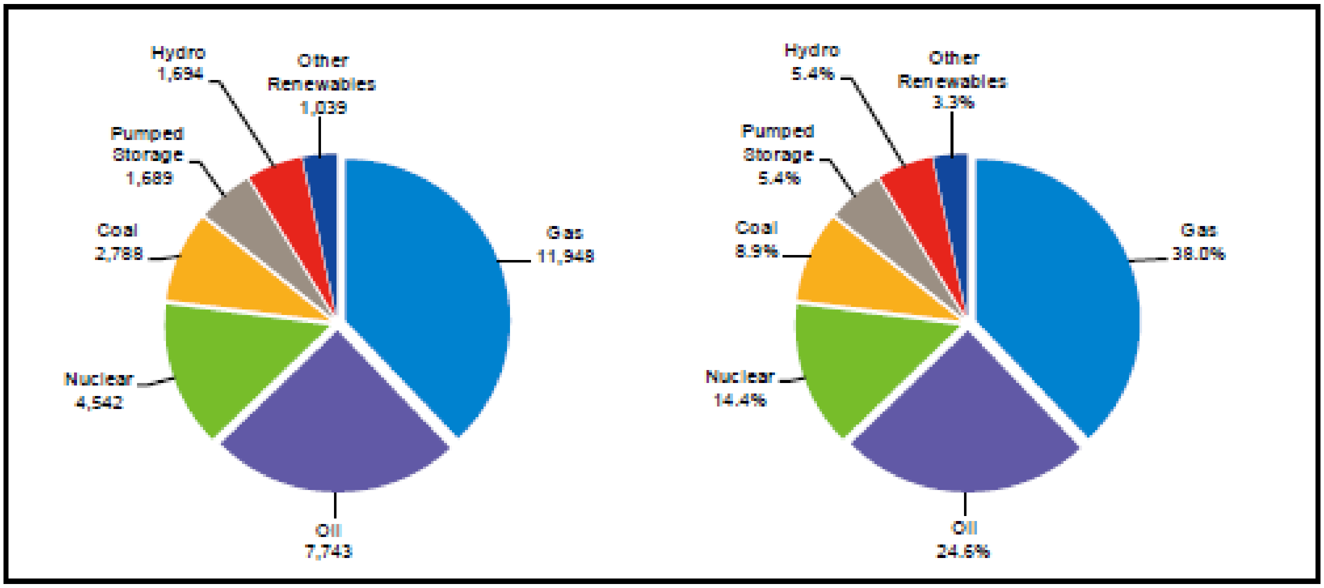

Figure 2–5 Generation capacity mix by primary fuel type, 2009 summer ratings (MW and %).

Note: The "Other Renewables" category includes LFG, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels. [2009 RSP, p. 61].

[55] FCA 2012/2013 cleared capacity includes 1008 MW of natural gas, 38 MW of landfill gas, 32 MW of biomass and wood/ wood waste, and 78 MW of wind generation

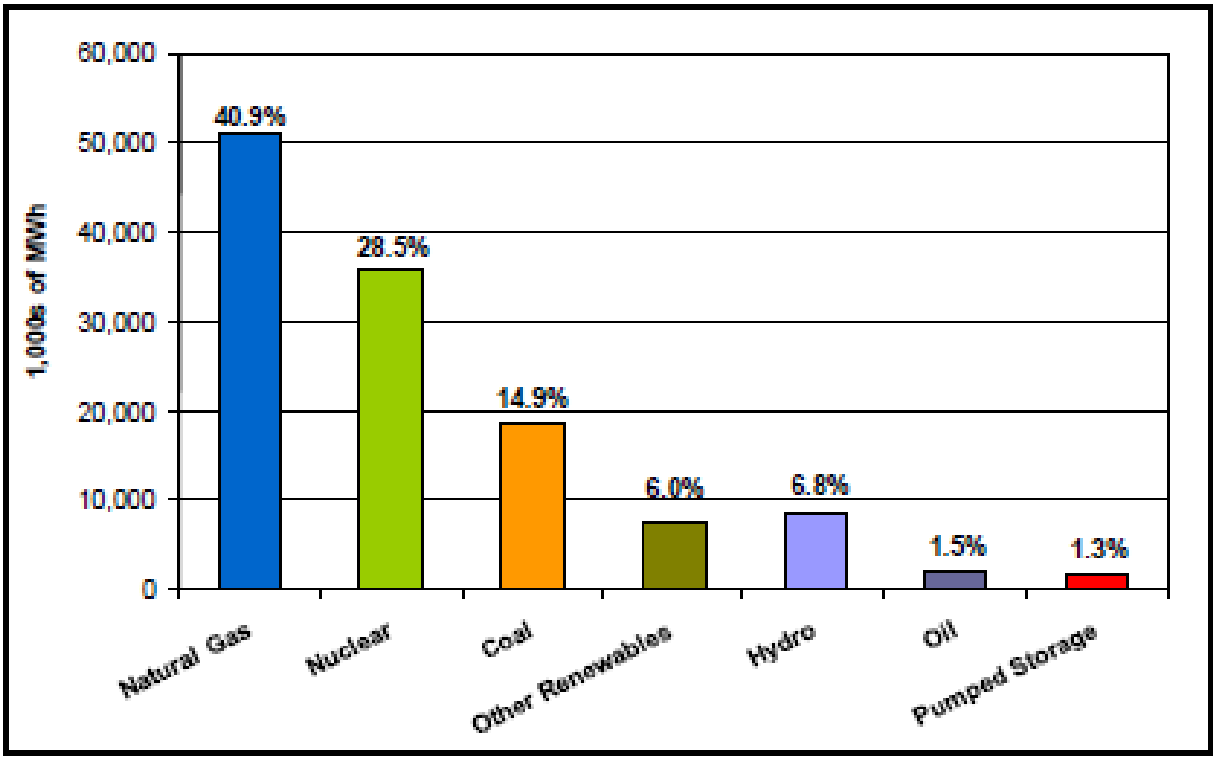

Figure 2–6 New England electric energy production by fuel type in 2008.

2.3.3 Partial Queue Build-Out

The partial queue represents a total of 1.14 GW of installed wind capacity, or approximately 2.5% of total annual energy demand forecasted for the New England region. Wind projects included are those either already in service, or are in the April 2009 Generation Queue that have obtained SIS/I.3.9 approval or have an SIS in progress. Therefore, this scenario is the nearest-term wind scenario, representing a regional pattern of wind development that may occur within the first few years of the NEWIS forecast horizon. The Partial Queue scenario is a subset of the Full Queue scenario.

Figure 2–7 depicts the approximate locations of wind projects included in the Partial Queue scenario. The magnitude of installed nameplate capacity corresponding to each site is represented by the size of the circle identifying it: the circles are not to-scale nor are they meant to be to-scale with the underlying figures. As Figure 2–7 illustrates, almost 80% of wind in the partial Queue scenario is located in Maine or off the coast of Massachusetts. The largest project in this scenario, a 460 MW offshore windplant, is visible in the figure as a blue dot located in Nantucket Sound off the coast of Massachusetts in the lower right-hand corner of the figure. A constant legend will be used in all following wind scenario layout figures in order to help the reader differentiate between sites in the different scenarios. This scenario adds no new transmission beyond the basecase 2019 ISO-NE Multi-regional Modeling Working Group (MMWG) library model. As mentioned previously, for more information about the transmission system assumptions please see section 2.3.9.3.

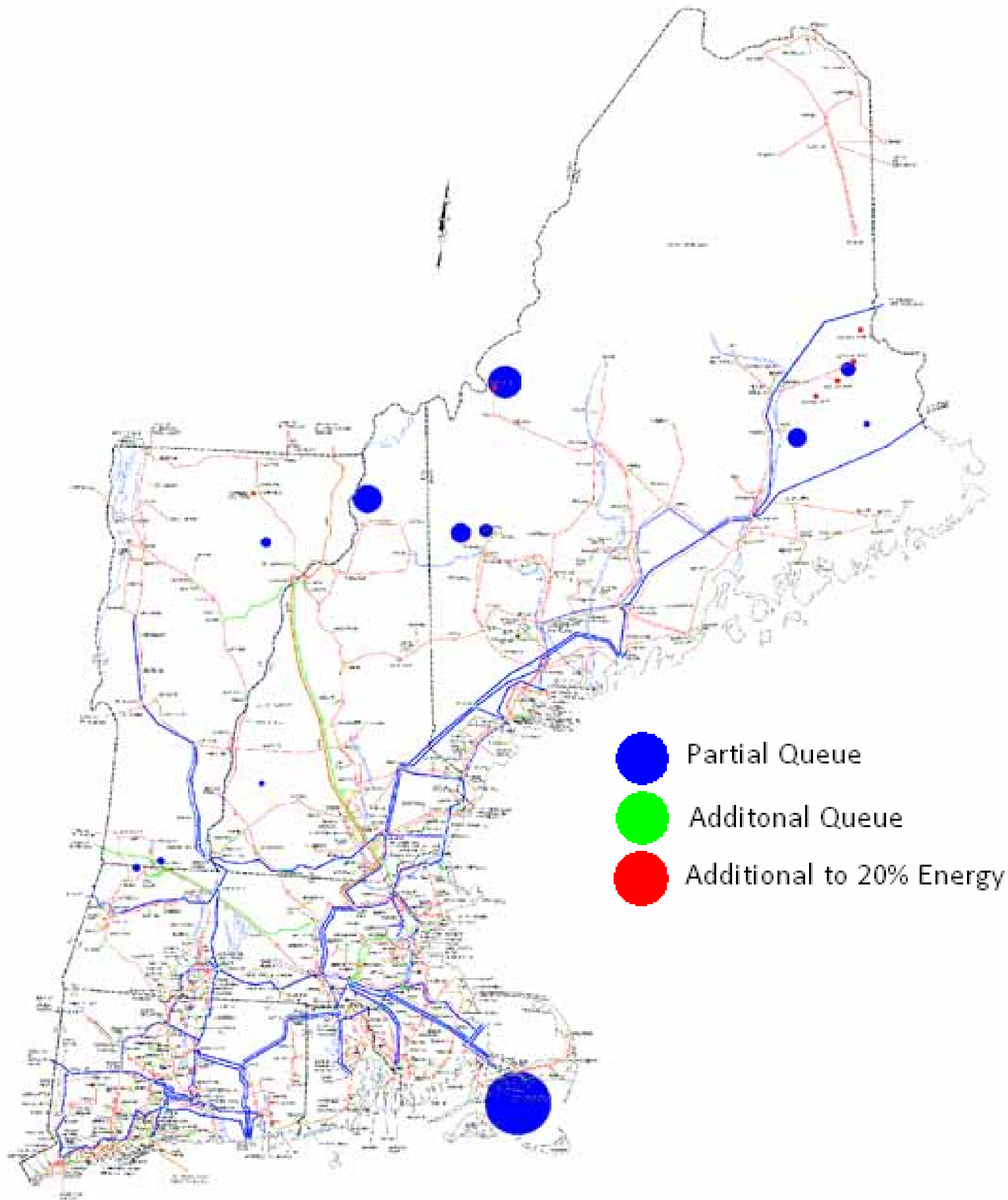

Figure 2–7 Locations of Partial Queue wind sites

Table 2–7 Partial Queue site breakdown

State	Onshore			Offshore			Total			Capacity Factor (%)		
	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	-	-	-	-	-	-	-	-	-	0%	0%	-
Maine	6	0.429	1,298	-	-	-	6	0.429	1,298	35%	0%	35%
Massachusetts	2	0.044	135	1	0.460	1,615	3	0.504	1,750	35%	40%	40%
New Hampshire	2	0.136	448	-	-	-	2	0.136	448	38%	0%	38%
Rhode Island	-	-	-	-	-	-	-	-	-	0%	0%	-
Vermont	2	0.071	198	-	-	-	2	0.071	198	32%	0%	32%
Total	12	0.680	2,080	1	0.460	1,615	13	1.140	3,695	35%	40%	37%

Table 2–7 is the Partial Queue site breakdown by state, type of wind plant (onshore versus offshore), capacity factor, total nameplate capacity and total energy contribution. Capacity factor and energy values are based on the three-year average energy outputs of each simulated wind plant. For example, Maine's onshore contribution consists of six sites totaling 429 MW in nameplate capacity, an average annual energy output of 1,298 GWh, and an average capacity factor of 35%.

2.3.4 Full Queue

The Full Queue represents a total of 4.17 GW of installed wind capacity, or approximately 9% of total annual energy demand for the New England region. Wind projects included are all of those in the Partial Queue, plus the remainder of wind sites in the Generation Queue regardless of SIS/I.3.9 status.[56] This scenario assumes the Governors' 2 GW Overlay for transmission is necessary in order to integrate the sites in Northern Maine.

[56] Wind projects listed as "Withdrawn" within the April 2009 Queue were not included in the full Queue build-out scenario. These sites were excluded since the reason for their withdrawal is unknown and may have included poor siting, e.g. location in an unfavorable wind regime.

Figure 2–8 is an illustration of sites included in the Full Queue. The additional sites, depicted in green, were not part of the Partial Queue scenario. As can be seen in Figure 2–8, sites added are predominantly located in Aroostook County, Maine, with one 360 MW offshore wind plant off the coast of Rhode Island. An important item of note is in order to facilitate this expansion, the assumption was made that transmission would be expanded into the northern portions of Maine (now interconnected via the New Brunswick system) using the Governors' 2 GW overlay.

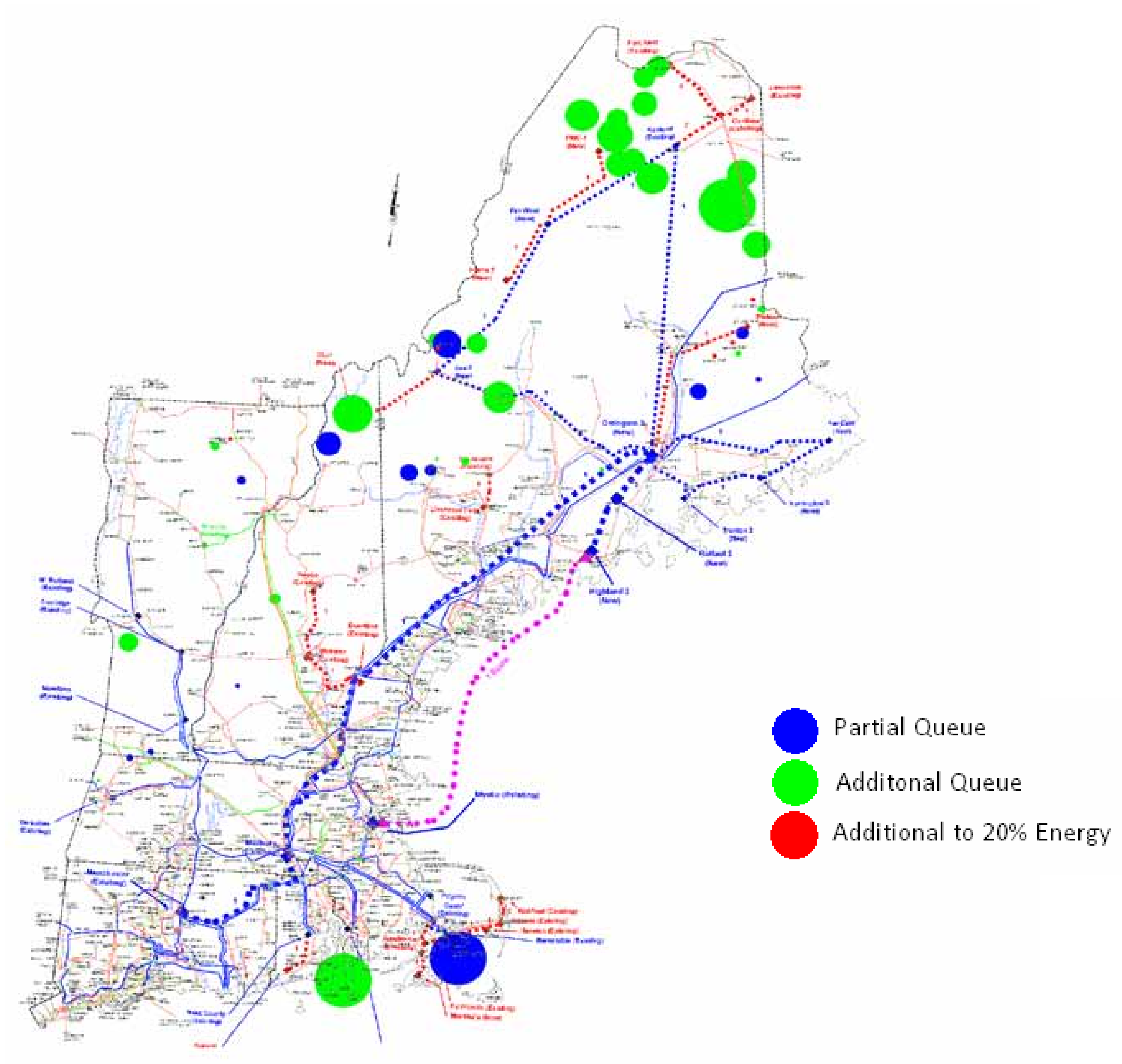

Figure 2–8 Full Queue wind site locations.

Table 2–8 Full Queue site breakdown

State	Onshore			Offshore			Total			Capacity Factor (%)		
	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	-	-	-	-	0.000	-	-	-	-	0%	0%	0%
Maine	28	2.681	7,486	-	0.000	-	28	2.681	7,486	32%	0%	32%
Massachusetts	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	5	0.400	1,290	-	0.000	-	5	0.400	1,290	37%	0%	37%
Rhode Island	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	5	0.209	584	-	0.000	-	5	0.209	584	32%	0%	32%
Total	41	3.349	9,543	2	0.820	2,910	43	4.169	12,453	33%	41%	34%

Table 2–8 is the Full Queue site breakdown. A total of 28 onshore sites in Maine are in the Full Queue, with an aggregate nameplate capacity of 2,681 MW, and an average annual output of 7,486 GWh and corresponding 32% capacity factor. One 360 MW offshore wind plant was added in Rhode Island. Note that the Full Queue scenario is a subset of all of the build-out scenarios featuring greater wind penetrations.

2.3.5 High Penetration Scenarios - 20% Energy

The purpose of the 20% energy target of the high penetration scenarios is to reflect the approximate effects of each state attempting to meet its RPS target using wind power. Additionally, there is ongoing discussion as to how large wind penetrations can be before alternative modes of study may be required[57]. Common thought is that this is somewhere in the range of 20% to 30% energy penetration, and so the NEWIS pushes this boundary while obtaining results that are relevant and well founded. All NEWIS 20% energy penetration scenarios use the Governors' 4 GW Overlay. In some cases (e.g. the Best by State Scenario, or the Best Offshore Scenario) portions of the overlay would be "overdesigned" and power flows on these portions would not reach the developed transfer limits.

[57] For example, incorporation of probabilistic planning techniques. see the NERC IVGTF report: http://www.nerc.com/files/IVGTF_Report_041609.pdf

2.3.5.1 Best Onshore + Full Queue – 20% Energy

The 20% Energy Full Queue plus Best Onshore scenario represents a total of 9.78 GW of installed wind capacity. Wind projects included are those in the Full Queue, plus the onshore sites within the NEWRAM with the highest capacity factor to meet the 20% regional energy target. Figure 2–9 illustrates the sites in this layout. Sites in red are not part of the Full Queue scenario. As can be seen in Figure 2–9, sites added are predominantly located in northern Maine, with several sites located in Vermont and New Hampshire. Due to lower capacity factors, only two additional sites are located in Massachusetts, no new sites are located in Rhode Island, and Connecticut remains without a wind project.

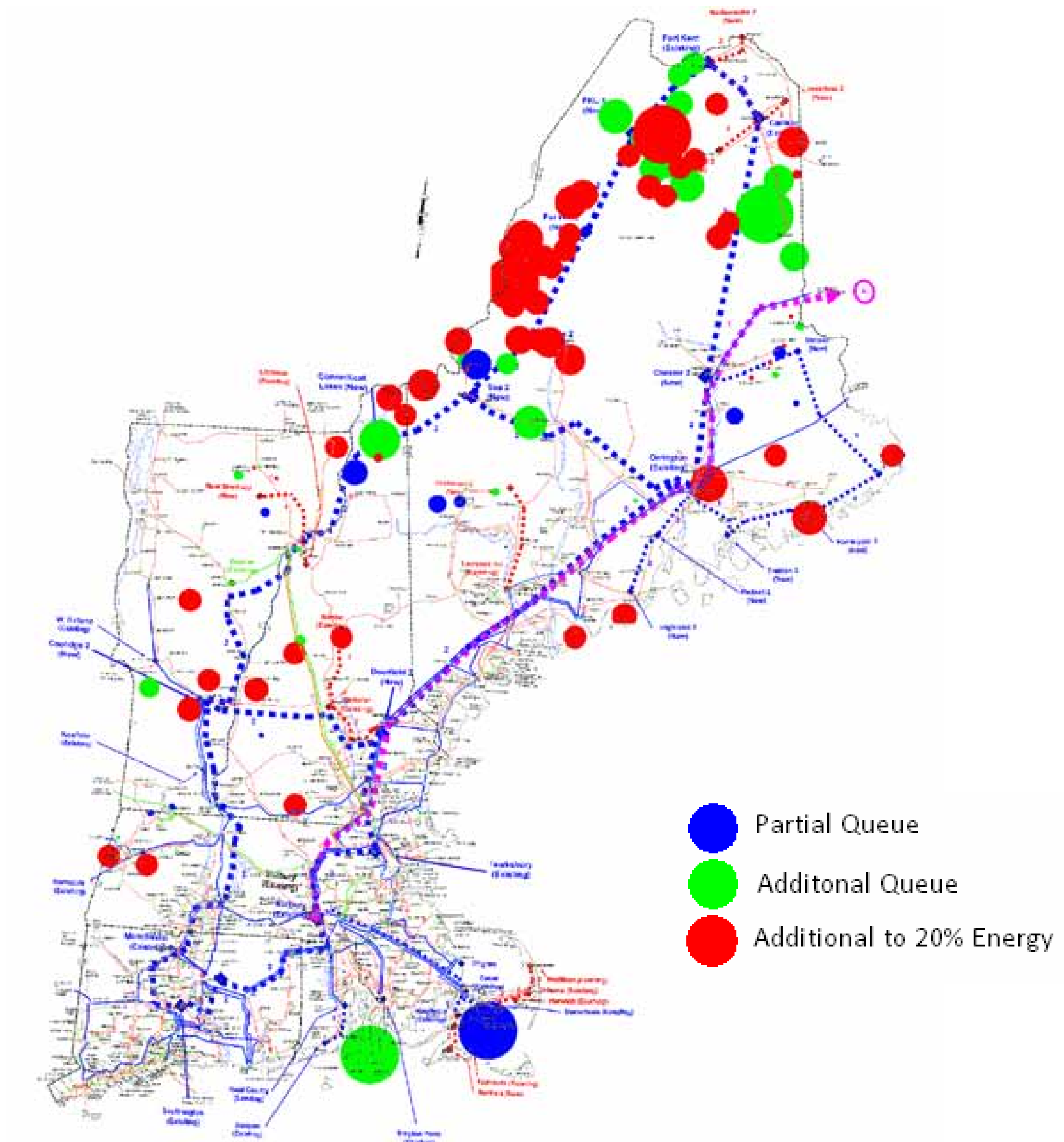

Figure 2–9 20% Energy Full Queue plus Best Onshore wind site locations

Table 2–9 20% Energy Full Queue plus Best Onshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	157%	63	7.001	20,226	-	-	-	63	7.001	20,226	33%	0%	33%
Massachusetts	4%	5	0.259	744	1	0.460	1,615	6	0.719	2,359	33%	40%	37%
New Hampshire	30%	12	1.064	3,335	-	-	-	12	1.064	3,335	36%	0%	36%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	23%	11	0.635	1,845	-	-	-	11	0.635	1,845	33%	0%	33%
Total	20%	91	8.959	26,150	2	0.820	2,910	93	9.779	29,060	33%	41%	34%

Table 2–9 is the 20% Energy Full Queue plus Best Onshore site breakdown. A total of 63 onshore sites are now located in Maine (35 of which are added to the full queue), with an aggregate nameplate capacity of 7,001 MW, and an average annual output of 20,226 GWh and corresponding 33% capacity factor. Maine wind plants therefore account for almost 70% of the total wind energy generated in this scenario, which is more than one-and-a-half times the state's annual energy demand. This scenario exhibits an overall 34% average capacity factor, which is lower than all but one of the other 20% energy scenarios, due to its emphasis on onshore wind development, which generally has a lower capacity factor than offshore wind power. Additionally, this scenario features a total of 91 wind plants, the most of the 20% scenarios.

2.3.5.2 Best Offshore + Full Queue – 20% Energy

The 20% Energy Full Queue plus Best Offshore scenario represents a total of 8.29 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, plus the offshore sites within the NEWRAM with the highest capacity factor that meet the 20% regional energy target.

Figure 2–10 is an illustration of sites included in the 20% Energy Full Queue plus Best Offshore scenario. Depicted in red are those sites not included in the Full Queue scenario. As can be seen in Figure 2–10 and Table 2–10, only four offshore wind plants (depicted in red in Figure 2–10) totaling 4,125 MW in nameplate capacity off the coast of Massachusetts are added to the Full Queue.

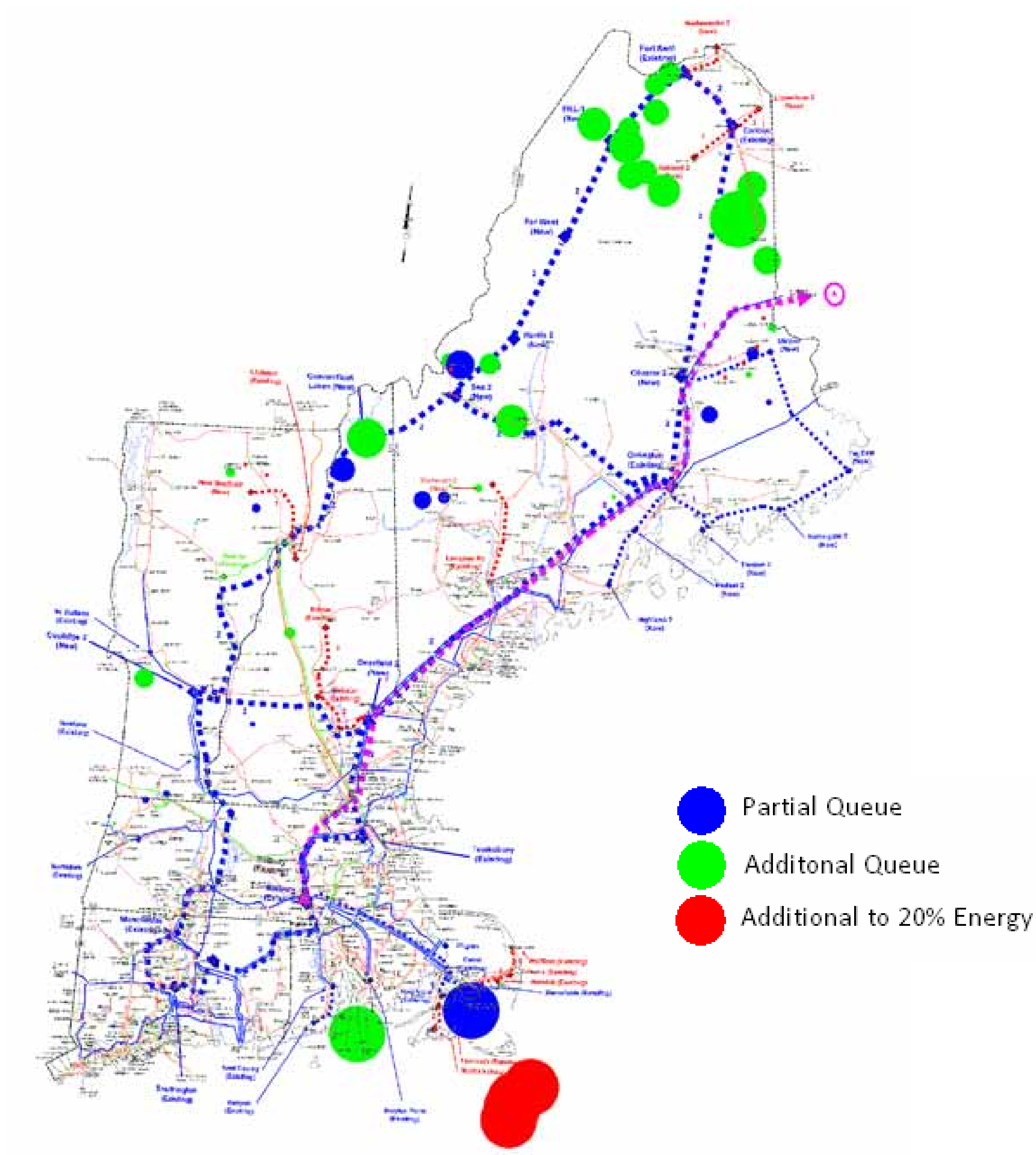

Figure 2–10 20% Energy Full Queue plus Best Offshore wind site locations

Table 2–10 20% Energy Full Queue plus Best Offshore site breakdown

		Onshore			Offshore			Total			Capacity Factor (%)		
State	% Energy by State	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	28%	3	0.059	183	5	4.585	18,222	8	4.644	18,405	35%	45%	45%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	20%	41	3.349	9,543	6	4.945	19,517	47	8.294	29,060	33%	45%	40%

Table 2–10 is the 20% Energy Full Queue plus Best Offshore site breakdown. The overall average capacity of the scenario is 40%, highest of the 20% scenarios. The five offshore wind plants in Massachusetts account for 55% of the nameplate capacity and almost 63% of the energy output region’s wind fleet. Compared to the regional onshore wind resource, the offshore wind resource is greater and features much less spatial variation (i.e. it is more consistent both temporally and spatially), which gives the offshore scenarios the highest capacity factors of all the study scenarios.

2.3.5.3 Balance Case[58] – 20 % Energy

The 20% Full Queue plus Balance Case represents a total of 8.80 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, plus the addition of 3.7 GW of offshore wind, and lastly the addition of onshore sites with the highest capacity factor required to meet the 20% total energy target. The offshore wind plants are divided evenly between the states of Maine, Massachusetts, and Rhode Island, each containing 1.5 GW of offshore wind nameplate capacity.

[58] Due to a naming convention change during the course of the NEWIS, this layout alternative can be found in this report listed as either the “Balance Case” or the “Best Sites”

Figure 2–11 is an illustration of sites included in the 20% Full Queue plus Balance Case. As can be seen, very few onshore sites have been added to the Full Queue portfolio, and there is a diverse distribution of wind plants across the region, including a fairly even distribution of offshore sites. Again, no wind projects are located in Connecticut due to its relatively poor wind resource, both onshore and offshore.

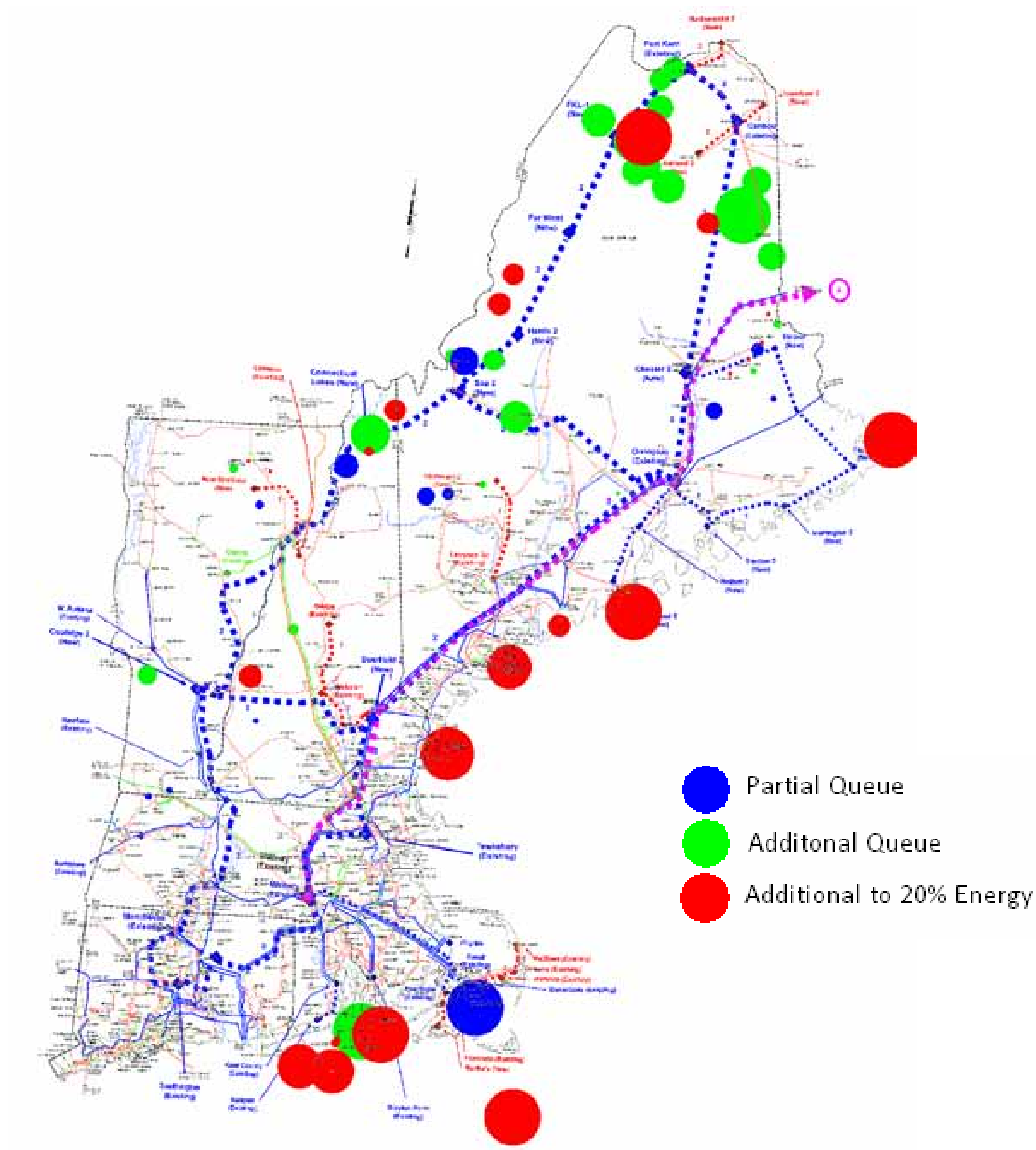

Figure 2–11 20% Energy Full Queue plus Balance Case wind site locations

Table 2–11 20% Energy Full Queue plus Balance Case site breakdown

State	% Energy by State	Onshore Site Count	Onshore Name Plate (GW)	Onshore Energy (GWh)	Offshore Site Count	Offshore Name Plate (GW)	Offshore Energy (GWh)	Total Site Count	Total Name Plate (GW)	Total Energy (GWh)	Capacity Factor (%) Onshore	Capacity Factor (%) Offshore	Capacity Factor (%) Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	114%	33	3.372	9,571	4	1.500	5,169	37	4.872	14,740	32%	39%	35%
Massachusetts	9%	3	0.059	183	2	1.498	5,800	5	1.557	5,982	35%	44%	44%
New Hampshire	19%	8	0.647	2,096	-	-	-	8	0.647	2,096	37%	0%	37%
Rhode Island	44%	-	-	-	7	1.513	5,657	7	1.513	5,657	0%	43%	43%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	20%	49	4.287	12,435	13	4.511	16,625	62	8.798	29,060	33%	42%	38%

Table 2–11 is the 20% Full Queue plus Balance Case site breakdown. Non-Queue sites selected for this 20% scenario include a total of 8 onshore wind plants with an aggregate nameplate capacity of 938 MW, and 11 offshore sites totaling 3,691 MW. Due to the large component of offshore wind (there is almost an even split between offshore and onshore total wind capacity) this scenario has a 38% capacity factor, second highest of the 20% scenarios. A total of 37 wind plants (33 onshore, 4 offshore) are sited in Maine, with an aggregate nameplate capacity of 4,872 MW, and a total average annual output of 14,740 GWh, or half of the total wind energy generated in this scenario.

2.3.5.4 *Best By State + Full Queue – 20% Energy*

The 20% Energy Full Queue plus Best By State scenario represents a total of 10.24 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, plus the addition of both onshore and offshore sites within each state to attempt to meet approximately 20% of each state's energy demand. Due to the disproportionate amount of Maine wind plants in the Queue, it had already met 58% of its own average annual energy demand without any additions. This meant that in order to meet the 20% regional target, the state energy targets of additional wind plants sited in other states had to be lowered commensurately, i.e. wind plants sited in Connecticut, Massachusetts and Rhode Island generate 16% of their respective annual state energy demands.

Figure 2–12 is an illustration of sites included in the 20% Energy Full Queue plus Best By State scenario, and depicts a high diversity of onshore wind, and a strong correlation between wind plant scenario layout and load centers, especially in southern New England. Due to lower capacity factors and higher loads within the states, many onshore sites are located in Massachusetts and Connecticut. For Massachusetts, it was decided that a fleet of mostly onshore sites in the state would possibly enable the study of different operational effects versus the 20% Best Offshore scenario due to the enhanced diversity of onshore fleet.

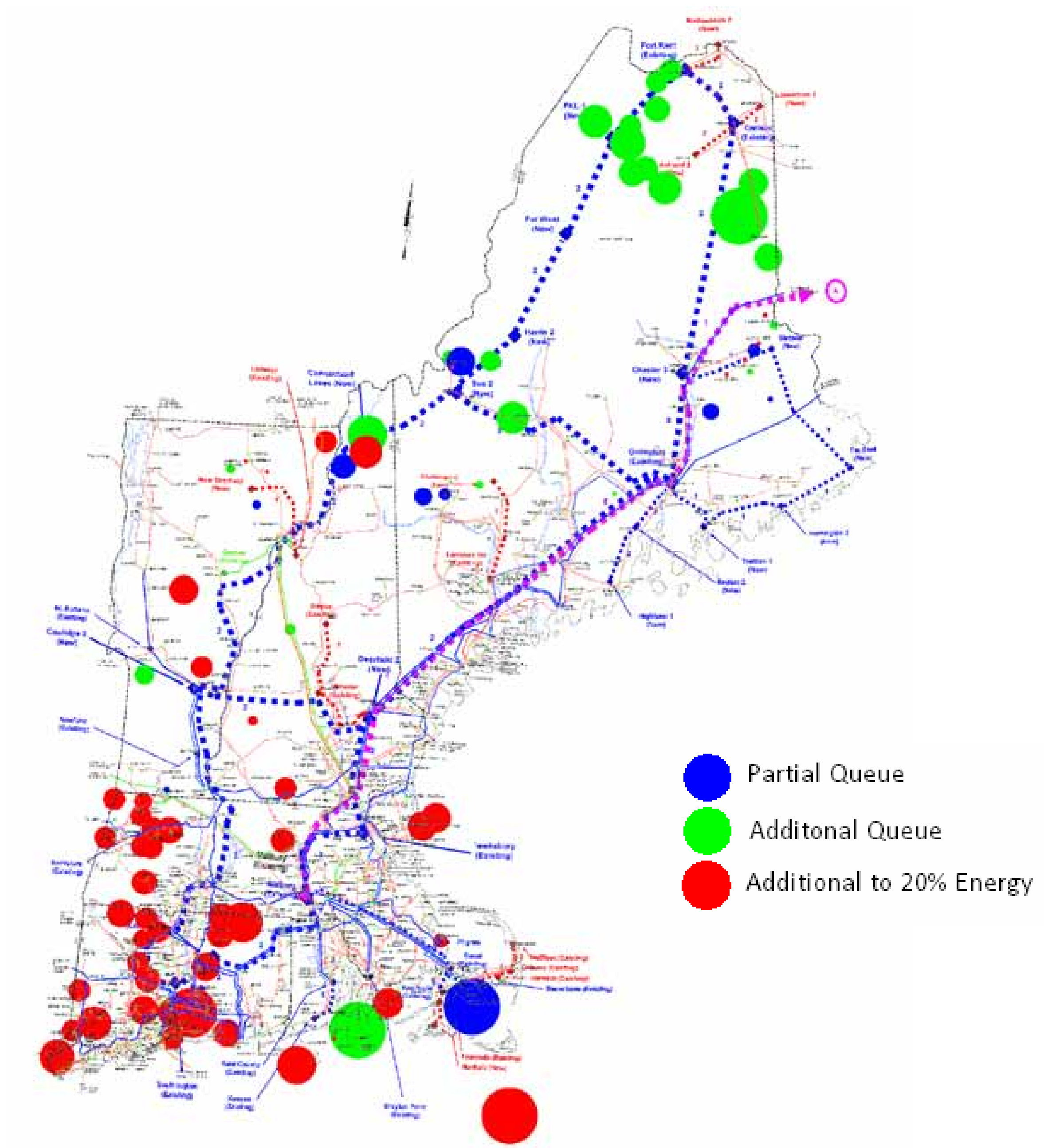

Figure 2–12 20% Energy Full Queue plus Best By State wind site locations

Table 2–12 20% Energy Full Queue plus Best By State site breakdown

State	% Energy by State	Onshore Site Count	Onshore Name Plate (GW)	Onshore Energy (GWh)	Offshore Site Count	Offshore Name Plate (GW)	Offshore Energy (GWh)	Total Site Count	Total Name Plate (GW)	Total Energy (GWh)	Capacity Factor (%) Onshore	Capacity Factor (%) Offshore	Capacity Factor (%) Total
Connecticut	16%	20	2.642	5,604	-	-	-	20	2.642	5,604	24%	0%	24%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	16%	22	1.619	4,353	2	1.498	5,800	24	3.117	10,153	31%	44%	37%
New Hampshire	20%	8	0.691	2,208	-	-	-	8	0.691	2,208	36%	0%	36%
Rhode Island	16%	-	-	-	3	0.555	2,019	3	0.555	2,019	0%	42%	42%
Vermont	20%	9	0.549	1,591	-	-	-	9	0.549	1,591	33%	0%	33%
Total	20%	87	8.182	21,241	5	2.053	7,818	92	10.235	29,060	30%	43%	32%

Table 2–12 is the 20% Energy Full Queue plus Best By State site breakdown. This scenario exhibits the lowest overall capacity factor of 34% due to emphasis on using in-state wind development to supply a significant portion of each state's annual energy demand, thereby requiring the incorporation of many sites with significantly lower capacity factors. The 24% capacity factor of Connecticut-based wind plants highlights this fact.

2.3.5.5 Maritimes + Full Queue – 20 % Energy

The 20% Energy Full Queue plus Best Sites Maritimes scenario represents a total of 8.96 GW of installed wind capacity. Wind projects included are all of those in the Full Queue, and the addition of the best (by capacity factor) onshore Maritime sites sufficient to meet the 20% regional energy target. It is assumed that all of the wind power generated in the Maritimes will be exported to the New England Control Area without any filtering or smoothing of the energy flow by the Maritimes systems (i.e. all volatility is exported).

Figure 2–13 is an illustration of sites included in the 20% Energy Full Queue plus Maritimes scenario. Depicted in red are sites located in the Maritimes, which exhibit a moderate spatial diversity within the Maritime region, with greater penetrations in Nova Scotia and Prince Edward Island, and much less in New Brunswick.

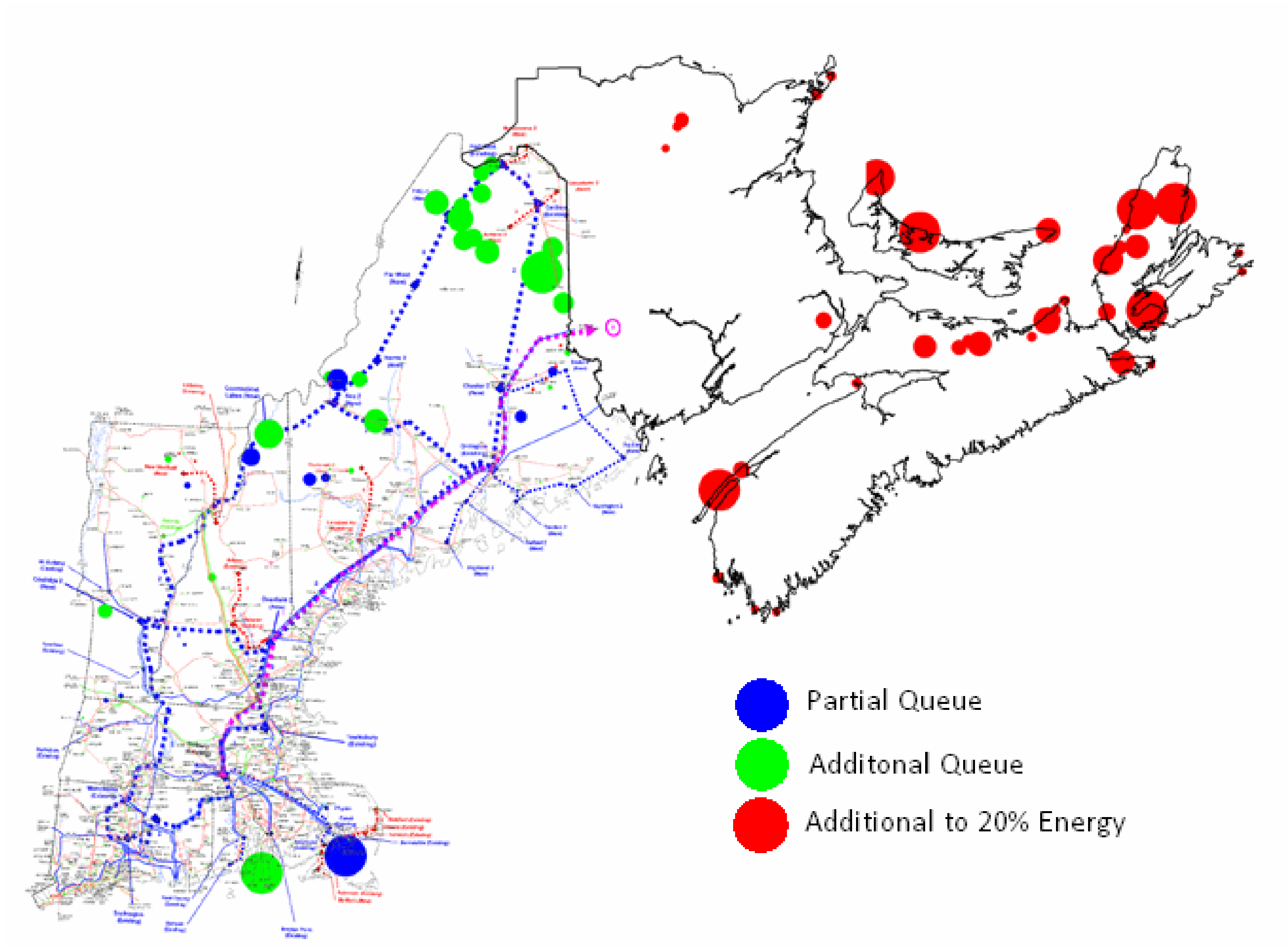

Figure 2–13 20% Energy Full Queue plus Best Sites Maritimes wind site locations

Table 2–13 20% Energy Full Queue plus Best Sites Maritimes site breakdown

State	% Energy by State	Onshore Site Count	Onshore Name Plate (GW)	Onshore Energy (GWh)	Offshore Site Count	Offshore Name Plate (GW)	Offshore Energy (GWh)	Total Site Count	Total Name Plate (GW)	Total Energy (GWh)	Capacity Factor (%) Onshore	Capacity Factor (%) Offshore	Capacity Factor (%) Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	3%	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Maritimes		35	4.787	16,607	-	-	-	35	4.787	16,607	40%	0%	40%
Total	20%	76	8.136	26,150	2	0.820	2,910	78	8.956	29,060	37%	41%	37%

Table 2–13 is the 20% Energy Full Queue plus Best Sites Maritimes site breakdown. A total of 35 wind plants located in the Maritimes exhibit a 40% capacity factor, and contribute an average annual energy output of 16,607 GWh, or slightly more than half of 20% of New England's forecasted (average) regional energy demand. Due to the quality of the wind resource in the Maritimes, the overall average capacity of this scenario is 37%, which rivals the balance case.

2.3.6 Medium Penetration Scenarios - 14%Energy

The 14% energy cases serve as midpoint cases between the Full Queue buildout and the 20% cases, and are a subset of the 20% scenarios. As such, the overall pattern of wind development of the 14% scenarios are identical (but with a lower installed wind capacity) to their respective 20% scenario counterparts, which are all described in detail above. Therefore, the discussion of each of the 14% scenarios that follows below will focus mainly on the differences relative to the 20% scenarios to avoid repetition. All 14% energy cases use the Governors' 2 GW overlay.

2.3.6.1 Best Onshore + Full Queue – 14% Energy

The 14% Energy Full Queue plus Best Onshore scenario represents a total of 6.75 GW of installed wind capacity. Figure 2–14 is an illustration of all scenario sites, which are broken down categorically in Table 2–14. Similar to the 20% Best Onshore scenario, the non-Queue component of the 14% onshore scenario is comprised predominantly of wind plants located in Maine. A total of 44 onshore sites (16 of which are non-Queue sites) are located in Maine with an aggregate nameplate capacity of 4,584 MW, generating an average annual output of 13,281

GWh, or more than 65% of the total wind energy generated in this scenario. Most of the sites that were omitted from the 20% Best Onshore scenario to create this scenario were located in Maine; 19 wind plants totaling 2,417 GW in nameplate capacity were removed from Maine, whereas a total of only 8 sites were removed from Massachusetts, New Hampshire and Vermont combined, with an aggregate capacity of 616 MW.

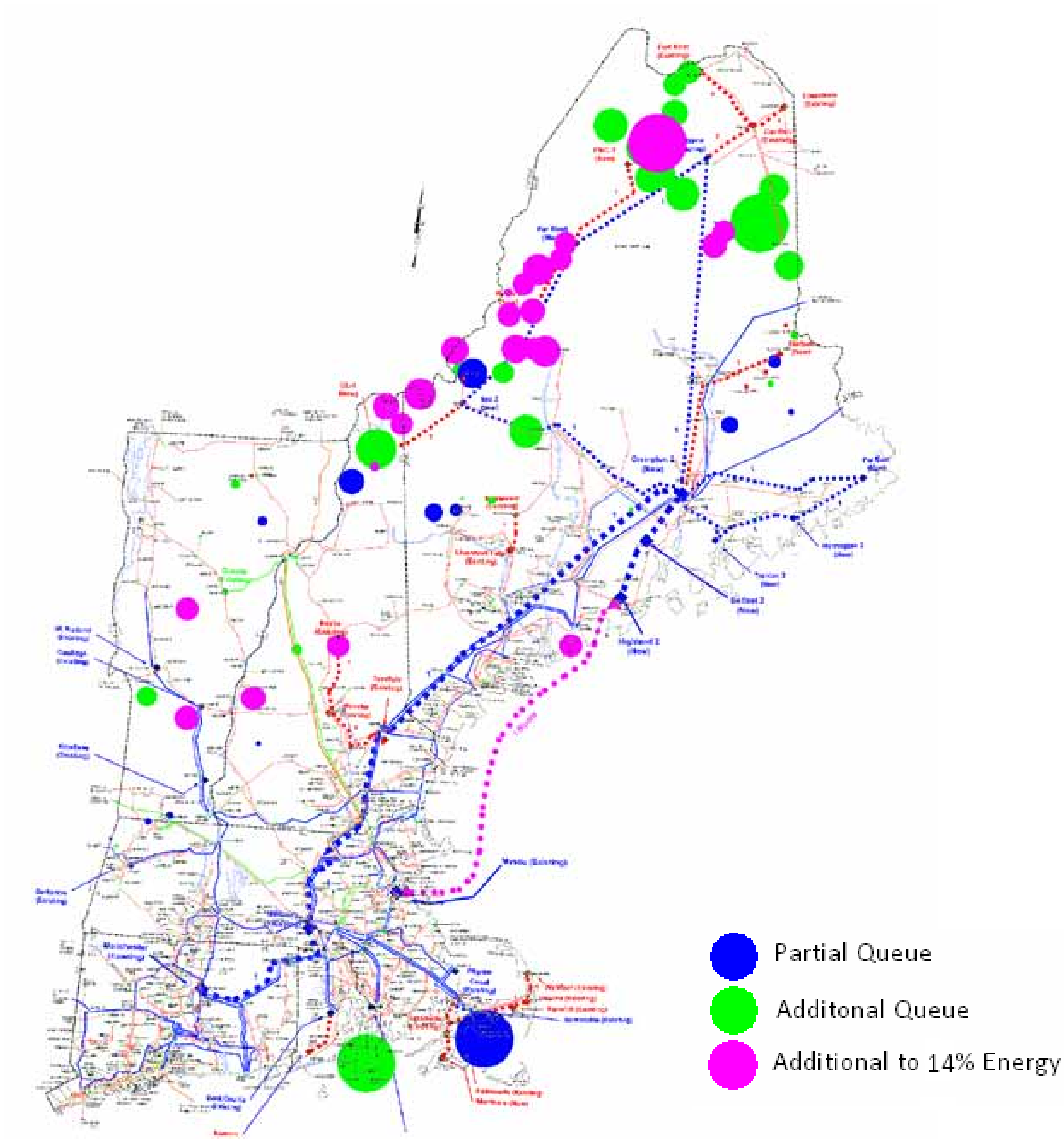

Figure 2–14 14% Energy Full Queue plus Best Onshore wind site locations

Table 2–14 14% Energy Full Queue plus Best Onshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	103%	44	4.584	13,281	-	-	-	44	4.584	13,281	33%	0%	33%
Massachusetts	3%	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	25%	10	0.864	2,746	-	-	-	10	0.864	2,746	36%	0%	36%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	16%	7	0.419	1,223	-	-	-	7	0.419	1,223	33%	0%	33%
Total	14%	64	5.926	17,432	2	0.820	2,910	66	6.746	20,342	34%	41%	34%

2.3.6.2 Best Offshore + Full Queue – 14% Energy

The 14% Energy Full Queue plus Best Offshore scenario represents a total of 6.13 GW of installed wind capacity. The sites in this scenario layout are illustrated in Figure 2–15 and categorized in Table 2–15. Similar to the 20% Best Offshore scenario, wind plants (depicted in red) located off the coast of Massachusetts make up the entire non-Queue component of this 14% scenario. Four wind plants (three in Massachusetts and one in Rhode Island) totaling 2,780 MW in nameplate capacity produce 53% of the total wind energy generated in this scenario. Since the proportion of offshore resources is lower than in the 20% offshore scenario, the overall capacity factor of this scenario is lower (38% compared to 40% for the high penetration case).

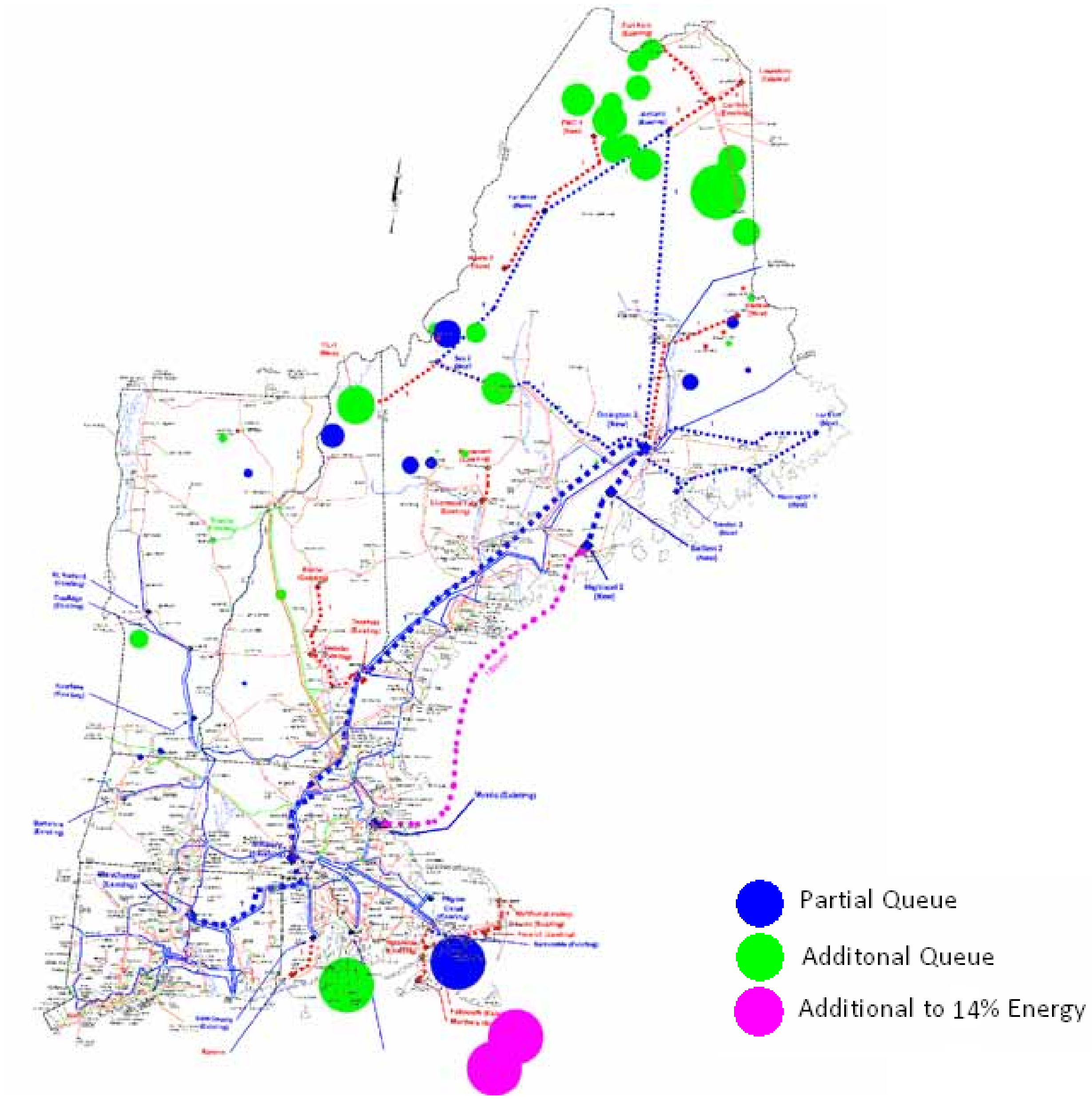

Figure 2–15 14% Energy Full Queue plus Best Offshore wind site locations

Table 2–15 14% Energy Full Queue plus Best Offshore site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	15%	3	0.059	183	3	2.420	9,504	6	2.480	9,687	35%	45%	45%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	14%	41	3.349	9,543	4	2.780	10,799	45	6.130	20,342	33%	44%	38%

2.3.6.3 "Balance Case" – 14% Energy

The 14% Energy Full Queue plus Balance Case represents a total of 6.31 GW of installed wind capacity. Figure 2–16 shows the graphical distribution of this scenario's sites, which are broken down categorically in Table 2–16. Similar to the 20% Balance case, offshore wind is divided evenly among Maine, Massachusetts, and Rhode Island; however, for the 14% balance case approximately 1 GW of offshore wind is developed in each of these states, rather than 1.5 GW developed in the 20% balance case. This lower proportion of offshore capacity translated into a slight reduction in overall capacity factor for the 14% case (37% rather than 38%). Another key difference is that no non-Queue onshore wind plants are required for this scenario.

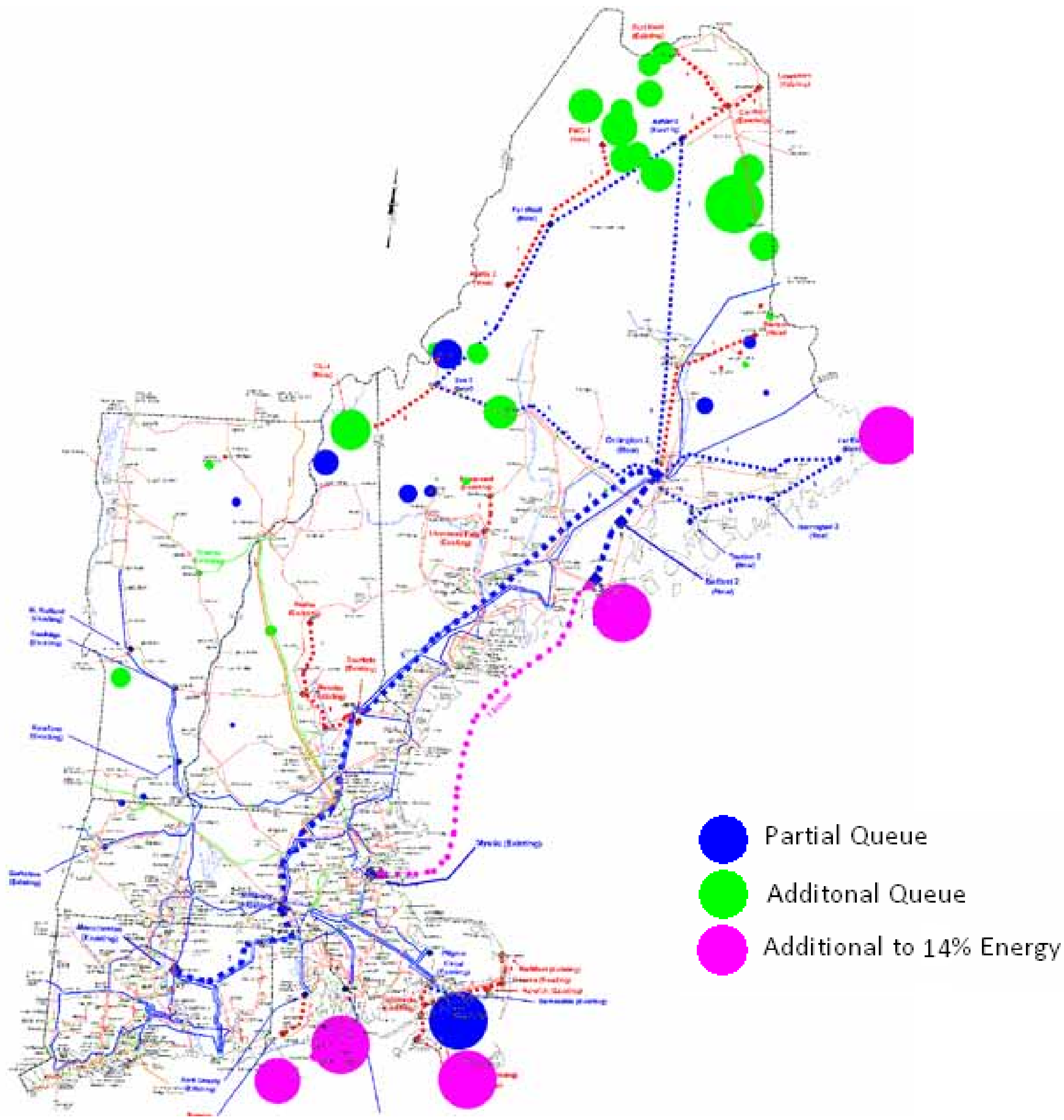

Figure 2–16 14% Energy Full Queue plus Balance Case wind site locations

Table 2–16 14% Energy Full Queue plus Balance Case site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	85%	28	2.681	7,486	2	0.986	3,523	30	3.667	11,008	32%	41%	34%
Massachusetts	6%	3	0.059	183	2	0.986	3,703	5	1.045	3,885	35%	43%	42%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	28%	-	-	-	5	0.986	3,573	5	0.986	3,573	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	14%	41	3.349	9,543	9	2.957	10,799	50	6.306	20,342	33%	42%	37%

2.3.6.4 Best By State + Full Queue – 14% Energy

The 14% Energy Full Queue plus Best By State scenario represents a total of 7.25 GW of installed wind capacity. Figure 2–17 is an illustration of this scenario's sites, which are broken down categorically in Table 2–17. Similar to the 20% best-by-state methodology, offshore and onshore wind plants were added to the Full Queue sites so that each state's wind portfolio could meet approximately 14% of its average annual energy demand, but again, due to the disproportionate amount of Maine wind power present in the Queue (2,681 MW generating 58% of the state's average energy demand), other state energy targets had to be lowered to satisfy the regional 14% energy target. The portion of each state's annual energy demand contributed by its instate wind portfolio include: 9% for Connecticut, Massachusetts and Vermont, 10% for Rhode Island, and 12% for New Hampshire. In sum, the 14% Best-By-state scenario is comprised of a total of 67 onshore sites with an aggregate capacity of 6,142 MW and 3 offshore sites with an aggregate capacity of 1,110 MW (versus 87 onshore sites totaling 8,182 MW and 5 offshore sites totaling 2,053 MW for the 20% case). Similar to the 20% Best-By-State scenario, this scenario exhibits the lowest overall capacity factor of all the 14% energy cases.

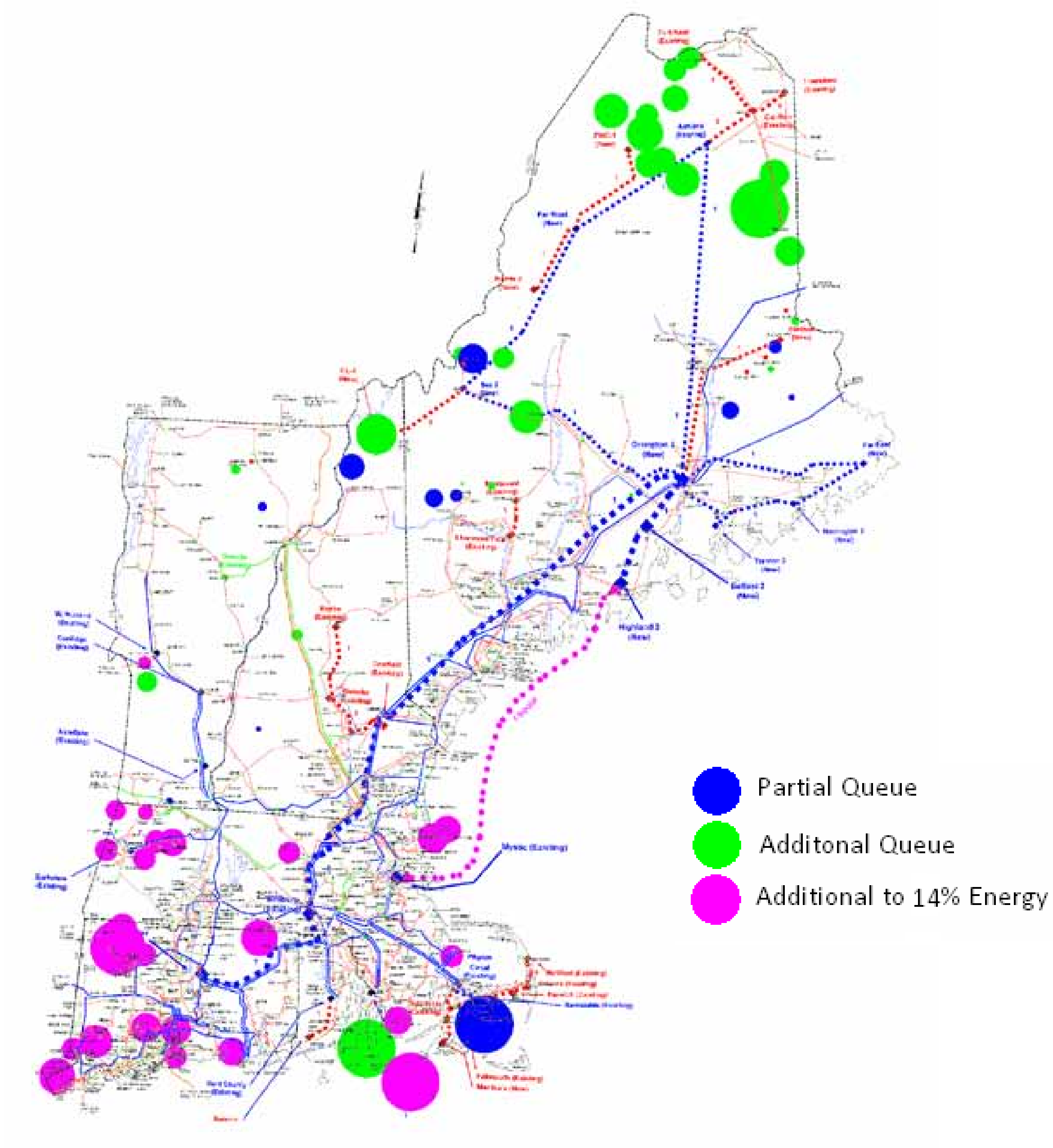

Figure 2–17 14% Energy Full Queue plus Best By State wind site locations

Table 2–17 14% Energy Full Queue plus Best By State site breakdown

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	9%	11	1.522	3,306	-	-	-	11	1.522	3,306	25%	0	25%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	9%	17	1.272	3,454	2	0.750	2,766	19	2.022	6,220	31%	42%	35%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	9%	6	0.267	744	-	-	-	6	0.267	744	32%	0%	32%
Total	14%	67	6.142	16,281	3	1.110	4,061	70	7.252	20,342	30%	42%	32%

2.3.6.5 *Maritimes + Full Queue – 14% Energy*

The 14% Energy Full Queue plus Best Sites Maritimes scenario represents a total of 6.39 GW of installed wind capacity. Figure 2–18 depicts the spatial distribution of this scenario's sites, which are broken down categorically in Table 2–18. This scenario is identical to its 20% counterpart except that 18 Maritimes sites have been omitted, giving a total Maritimes nameplate wind capacity of 2,225 MW instead of 4,787 MW (in the 20% case).

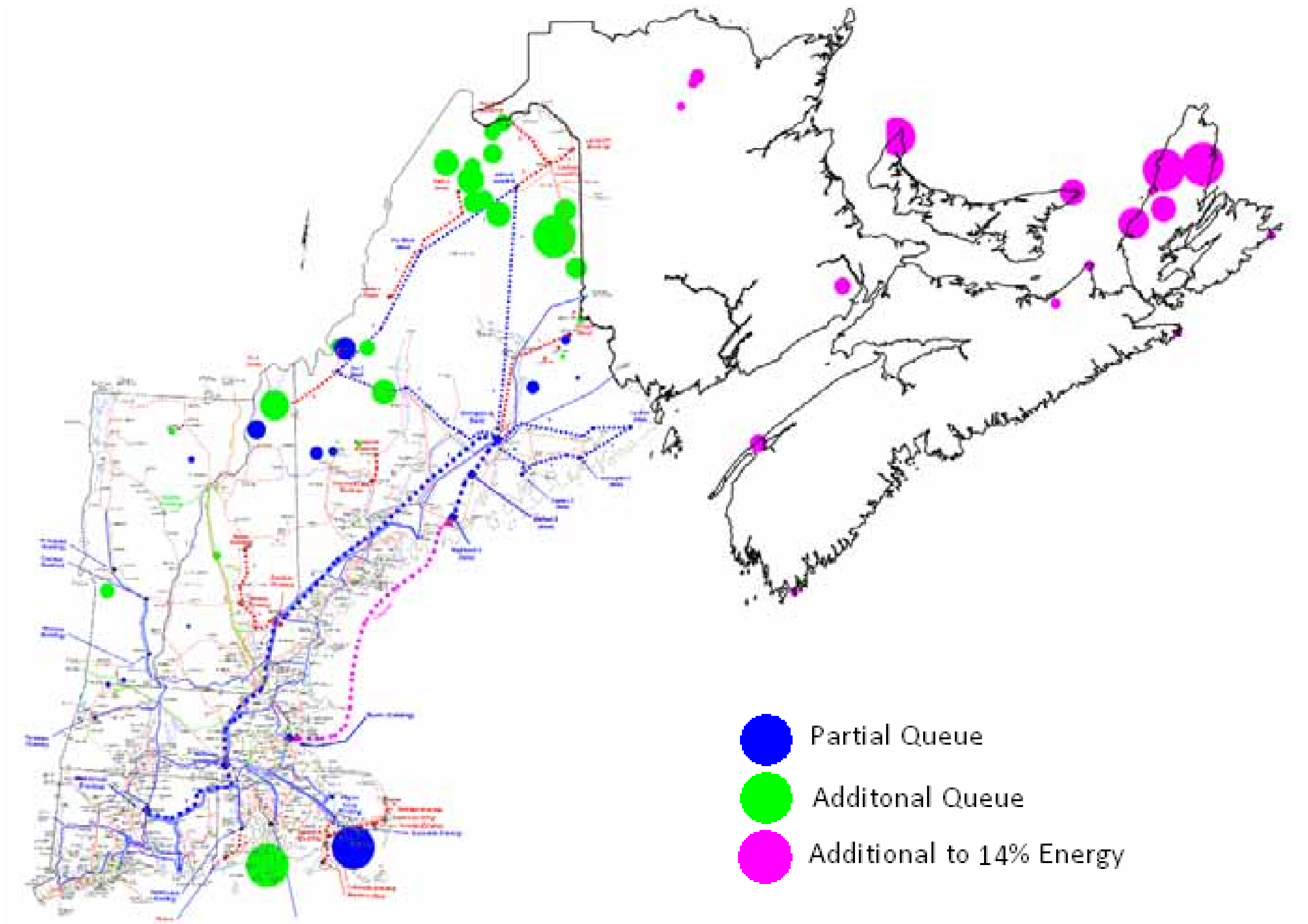

Figure 2–18 14% Energy Full Queue plus Best Sites Maritimes wind site locations

Table 2–18 14% Energy Full Queue plus Best Sites Maritimes site breakdown

State	% Energy by State	Onshore Site Count	Onshore Name Plate (GW)	Onshore Energy (GWh)	Offshore Site Count	Offshore Name Plate (GW)	Offshore Energy (GWh)	Total Site Count	Total Name Plate (GW)	Total Energy (GWh)	Capacity Factor (%) Onshore	Capacity Factor (%) Offshore	Capacity Factor (%) Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	3%	3	0.059	183	1	0.460	1,615	4	0.519	1,798	35%	40%	40%
New Hampshire	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Maritimes		17	2.225	7,889	-	-	-	17	2.225	7,889	40%	0%	40%
Total	14%	58	5.574	17,432	2	0.820	2,910	60	6.394	20,342	36%	41%	36%

2.3.7 Extra-High Penetration Scenarios - 12 GW Wind

The extra-high wind penetration scenarios were designed to identify operational issues in the region's bulk power system at wind penetrations exceeding 20%. Starting with their 20% scenario counterpart, the 20% Energy Full Queue plus Best Sites Onshore scenario, they were developed by the addition of other NEWRAM sites that have the next highest capacity factors. As such, their descriptions below will focus mainly on the characteristics of the wind plants that were not present in the 20% scenarios. The extra-high wind penetration scenarios use the Governors' 8 GW Overlays.

2.3.7.1 Best Onshore + Full Queue – 12 GW Wind

The Best Onshore 12 GW scenario represents a total wind energy output equivalent to approximately 24% of the region's annual energy demand. Figure 2–19 depicts the spatial distribution of this scenario's sites, which are broken down categorically in Table 2–19. A total of 22 additional sites relative to the 20% best onshore case (9.78 GW wind capacity), are scattered throughout Maine (11 additional sites), Massachusetts (one additional site), New Hampshire (five additional sites), and Vermont (five additional sites).

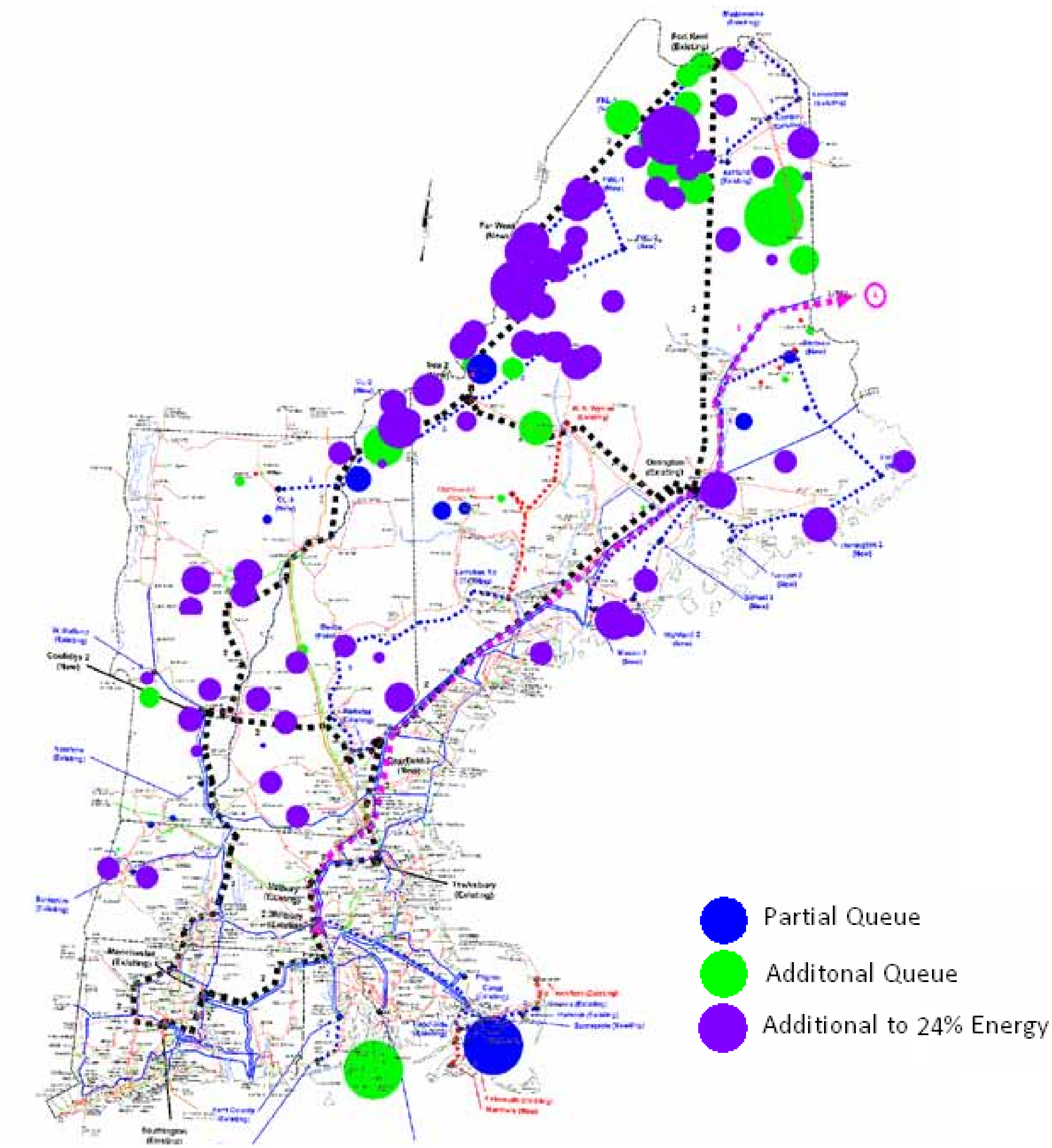

Figure 2–19 Locations of Best Onshore and Full Queue sites for 12 GW Nameplate

Table 2–19 Breakdown of Best Onshore and Full Queue sites for 12 GW Nameplate

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0	0%
Maine	178%	72	7.966	22,935	-	-	-	72	7.966	22,935	33%	0%	33%
Massachusetts	4%	7	0.279	800	1	0.460	1,615	8	0.739	2,415	33%	40%	37%
New Hampshire	44%	17	1.629	4,897	-	-	-	17	1.629	4,897	34%	0%	34%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	40%	16	1.113	3,159	-	-	-	16	1.113	3,159	32%	0%	32%
Total	24%	112	10.987	31,792	2	0.820	2,910	114	11.807	34,701	33%	41%	34%

2.3.7.2 Best Offshore + Full Queue – 12 GW Wind

The Best Offshore 12 GW scenario represents a total wind energy output equivalent to approximately 24% of the region's annual energy demand in order to be more directly comparable to the 12 GW Best Onshore Case and is therefore not 12 GW in nameplate due to the high capacity factor of the offshore wind resource. Figure 2–20 depicts the spatial distribution of this scenario's sites, which are categorized in Table 2–20. The total nameplate capacity in this scenario is approximately 9.7 GW. Two additional offshore wind sites have been added relative to the 20% Best Offshore case; both southeast of Massachusetts and totaling to 1412 MW.

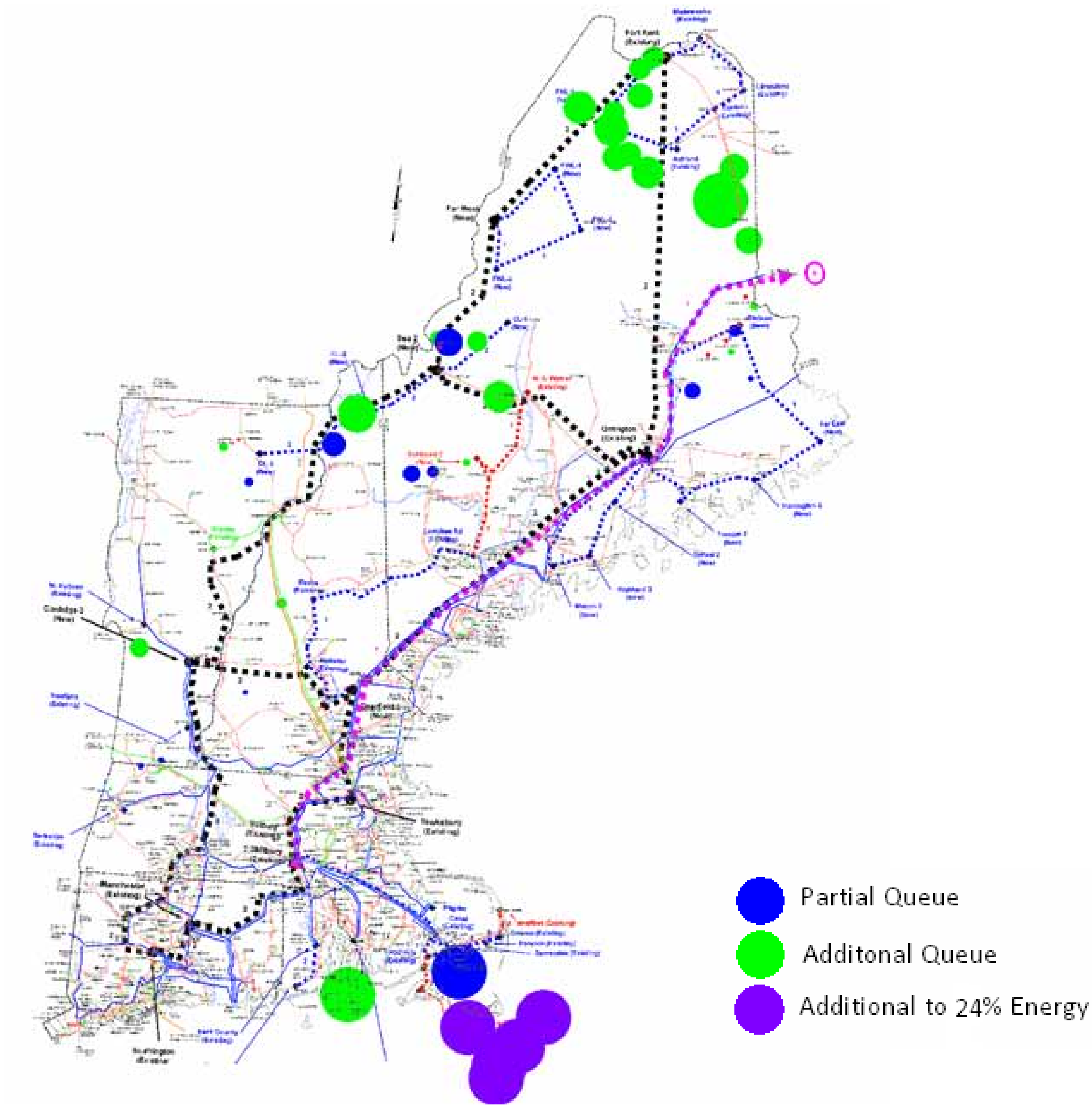

Figure 2–20 Locations of Best Offshore and Full Queue sites for comparison with 12 GW Onshore Case

Table 2–20 Breakdown of Best Offshore and Full Queue sites for comparison with 12 GW Onshore Case

State	% Energy by State	Onshore			Offshore			Total			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Total Energy (GWh)	Onshore	Offshore	Total
Connecticut	0%	-	-	-	-	-	-	-	-	-	0%	0%	0%
Maine	58%	28	2.681	7,486	-	-	-	28	2.681	7,486	32%	0%	32%
Massachusetts	37%	3	0.059	183	7	5.997	23,862	10	6.056	24,045	35%	45%	45%
New	12%	5	0.400	1,290	-	-	-	5	0.400	1,290	37%	0%	37%
Rhode Island	10%	-	-	-	1	0.360	1,295	1	0.360	1,295	0%	41%	41%
Vermont	7%	5	0.209	584	-	-	-	5	0.209	584	32%	0%	32%
Total	24%	41	3.349	9,543	8	6.357	25,157	49	9.706	34,700	33%	45%	41%

2.3.8 Sensitivity Cases

Sensitivity cases were also run using the 2006 year wind/load scenarios in order to investigate the influence that additional changes may have with regard to integrating large-scale of wind power for New England. These sensitivity cases include:

1. Double interface capability (Hydro-Quebec, New York, New Brunswick)

2. Quadrupling only the New Brunswick interface capability especially due to the large potential wind resource there.

3. Increasing the cost of carbon emissions from $0 per ton to a mid-case of $40 per ton to a high case of $65 per ton in order to investigate changes in dispatch.

4. Fuel price sensitivity – high and low with regard to base. The NEWIS assumed future prices based on the 2009 Energy Information Administration (EIA) Annual Energy Outlook.[59] EIA projects higher natural gas and oil prices, and relatively stable coal, biomass, and nuclear prices, over the long term.

[59] Energy Information Administration, 2009 Annual Energy Outlook, DOE/EIA-0383 (Washington DC: U.S. DOE, April 2009); http://www.eia.doe.gov/oiaf/aeo/index.html

5. A combination of high fuel prices and high carbon cost, low fuel prices and high carbon cost to not only account for a possible range of fuel price scenarios, but also to attempt to account for potential changes in fuel costs that may impact one fuel with respect to another (e.g. natural gas vs. coal).

6. Storage sensitivity – The impact of increased storage, based on utilization. Since this sensitivity was based on the utilization of existing storage and since (as will be seen later in this report) the existing storage was not fully utilized, this sensitivity case was not investigated.

7. Wind Forecast impacts – (No forecast, state-of-the-art forecast, perfect forecast) in order to investigate the operational effects of improving the wind power forecast.

2.3.9 Development of Transmission Overlays

2.3.9.1 Introduction

The location of much of the high capacity factor potential wind resource in New England does not correlate well with areas of high population and concentrated energy demand. In general, the region's population and electricity demand are concentrated in southern New England, while the best onshore wind resources are located in the north. This lack of spatial coincidence introduces a need for new transmission to connect potential wind resources to load centers throughout the region. Potential offshore wind resources are located much closer to load centers significantly reducing the amount of required transmission. Since a primary objective of the NEWIS is to identify the operational effects of large-scale integration of wind power, the role of transmission cannot be understated, especially given that many potential wind plants in New England could not feasibly be built and operated without the construction of new transmission. Figure 2–21 illustrates the poor correlation in the locations of regional wind resource and areas of greatest electricity demand.

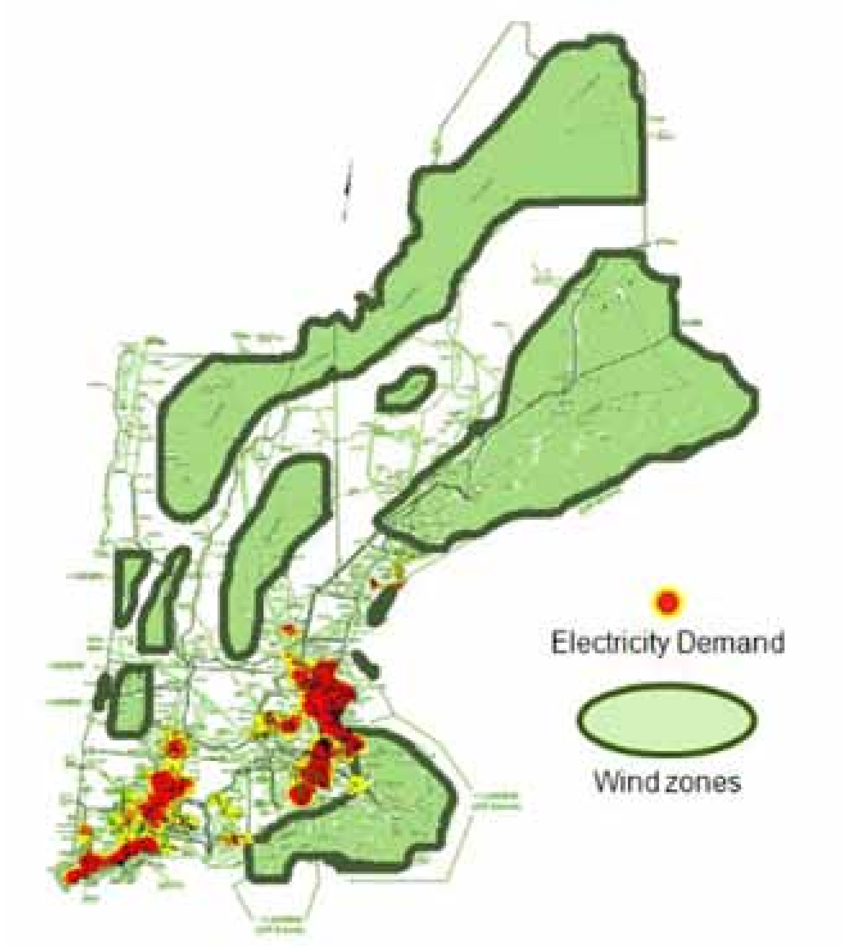

Figure 2–21 Potential wind zones and load centers in New England (Gov. Study, p. 6)

The NEWIS used three transmission overlays previously developed as part of a 2009 economic study conducted by the ISO for the New England Governors, hereafter referred to as the Governors' Study.[60] The following four transmission systems were developed and used for the NEWIS:

- 2019 ISO-NE System ("existing") – used for base case.
- Governors' 2 GW Overlay – used as developed for Governor's Study.

[60] New England 2030 Power System Study (February 2010); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/economicstudyreportfinal_022610.pdf.

- Governors' 4 GW Overlay/1,500 MW New Brunswick Interchange – An additional 345 kV line taken from the 8 GW Overlay was included for Southeastern Massachusetts in this overlay.
- Governors' 8 GW Overlay/1,500 MW New Brunswick Interchange

Due to scope constraints, only thermal limits were developed, investigated, and utilized for the NEWIS study. Voltage and stability limits would very likely reduce assumed transfer capability so the transfer capabilities of the hypothesized transmission expansion assumed in the study should be considered an upper bound.

Each of these systems is described in detail in subsequent sections below; however, a description of the Governor's Study is required first since the transmission used for the NEWIS is largely based on overlays developed for the Governor's Study.

2.3.9.2 Governor's Study

The Governor's Study adapted potential wind resources identified during a 2008 study conducted for the ISO by Levitan & Associates Inc. (LAI).[61] Since LAI used AWST's MesoMap system and a similar screening process as the NEWIS to identify viable wind resources, there is a strong geo-correlation of wind resources identified in both studies. Therefore, potential transmission identified for the Governor's Study is well-suited for the NEWIS.

This study identified potential transmission necessary to integrate a range of renewable resource expansion scenarios.[62] The base case or "constrained" case was selected using interface limit assumptions set forth in ISO's 2009 Regional System Plan (RSP)[63] (this system is referred to as the '2019 ISO-NE system', and is described further in the next section). The transmission overlays were designed to be robust, workable, and to ensure 100% deliverability of the renewable resources selected, i.e. the bulk power system was made "unconstrained" under each

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[61] Phase II Wind Study (Levitan & Associates Inc., March 2008) http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/lai_5-20-08.pdf

[62] The ISO retained the consulting firm, Energy Initiatives Group (EIG), to develop the transmission overlays.

[63] The interface limits modeled in the Governor's Study assume the completion of the New England East-West Solution (NEEWS) and the Maine Power Reliability Project (MPRP) transmission projects identified in the Regional System Plan; see http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf.

of the wind scenarios used in the Governor's Study.[64] The overlay design was strictly conceptual, considering only single-contingency thermal constraints.[65] Additionally, the Governor's study did not evaluate the feasibility of siting specific transmission projects, and potential transmission identified does not represent the future location of facilities; however, efforts were made to site potential transmission within existing rights-of-way while also accounting for alternative power flow paths in the event of a contingency. In general, the results of the study found a need for higher voltage classes of transmission introduced as the wind penetration gets significantly large (i.e. greater than 4 GW installed nameplate capacity).

Given that the core objectives of the Governor's Study were economic in nature, EIG developed preliminary order-of-magnitude cost-estimate ranges for each of the conceptual transmission expansions used. Note that no additional cost analyses or considerations regarding hypothetical transmission used were made for the NEWIS. Therefore, it is advised that readers interested in preliminary transmission costing refer to the Governor's Study.

2.3.9.3 Development of Overlays for NEWIS

In contrast to the Governor's Study, for which transmission overlays served only as wind delivery systems connected to the bulk system at major load centers, the overlays were integrated into the regional transmission system for the NEWIS. All collocated substations of the overlays and the 2019 ISO-NE system were tied together, thus allowing the overlays to act as conduits for loads and power generated by other sources, rather than just the wind. This was critical to developing hypothetical transmission that enables a realistic simulation of generation dispatch, which thereby yields realistic LMPs.

Wind build-out scenarios were matched with Governor's Study transmission overlay configurations and a preliminary copper sheet simulation was run to determine their respective suitability. Based on the copper sheet simulations and the developed thermal transfer limits, the overlays were found to be able to support more wind power than the wind scenarios used in the Governor's Study. For example, the Governors' 4 GW overlay, which was developed to be able to robustly deliver a total additional generation (i.e. wind)nameplate capacity of 4 GW, was

[64] Transmission constraints are the physical limitations of the bulk power system that reduce the ISO's ability to dispatch the lowest-priced resources to meet the regional electricity demand. Due to these constraints, the ISO may have to dispatch higher-priced resources, and the incremental increase in cost is reflected in wholesale electricity prices as congestion costs.

[65] Typical transmission designs are subjected to technical optimization and a rigorous voltage and stability analyses.

capable of transporting wind penetrations in the 20% energy scenario, or up to 9.77 GW of wind. The primary reasons smaller overlays are able to be used are that typical capacity factors of wind plants are between 20% and 45% due to the resource's variable nature and that geographic diversity limits the coincident output of the wind power fleet; nameplate, fully coincident output values were used for the Governor's Study. Thus, from a thermal transfer limit standpoint only, the overlays used in the Governor's Study are designed to address the long term expansion of the system beyond the immediate concern of integrating the wind generation postulated in the various scenarios. In consideration of wind plant interconnection, it is assumed that wind plants in each scenario are connected directly to the overlays. In effect this means that all local transmission needed to connect the wind to the overlays was presumed to already exist and that it is sufficiently robust to be unconstrained in all of the NEWIS wind scenarios. Because of this, during operational simulations conducted as part of the NEWIS, local transmission is "invisible" to the system. This is an important consideration in that the reader should not assume that for the study local transmission congestion could impede the deliverability of the wind to the larger transportation model. In fact due to the typical development pattern of wind generation facilities in New England and their interconnection under the minimum interconnection standards process, local interconnections are often the point at which congestion occurs which results in potential wind curtailments.

2.3.9.4 Validation of Power Flow Cases

ISO-NE provided GE the 2019 power flow base case. Based on the transmission overlay developed by EIG, GE built three additional power flow cases (Governors' 2 GW overlay, Governors' 4 GW overlay and Governors' 8 GW overlay) and delivered these to ISO-NE in PSSE RAW format.

ISO-NE then used Power World Simulator version 14 to validate that the power flow cases built by GE were consistent with the overlay developed by EIG. Power World Simulator has a function to compare topological differences between two power flow cases. It presents a report of what elements are added and removed in the present case from the base case. The topological difference reports generated by Power World Simulator were then compared to the transmission overlay by EIG side by side to make sure that the power flow cases have represented the transmission overlay correctly. There were several iterations between ISO-NE and GE in building and validating these cases. However, detailed and extensive engineering analysis regarding stability and voltage limits would be required in order to determine the true viability of the hypothesized transmission expansions, which was outside the scope of the NEWIS.

2.3.9.5 Developments of Interface Transfer Limits

After building and validating the power flow cases, ISO-NE inserted definitions for the interfaces (see Table 2–21) between RSP subareas for the 2019 base case, 2 GW overlay case, 4 GW overlay case and 8 GW overlay case: no new interfaces were created. Transfer limits were calculated for each interface of these power flow cases by using the Available Transfer Capability (ATC) module of Power World Simulator. The calculated interface limits were later reviewed at the Planning Advisory Committee and the NEWIS Technical Review Committee and used in the operational analysis performed using General Electric's Multi Area Production Simulation (GE MAPS) program.

Table 2–21 Transfer limits between RSP subareas

Interface Limits	2019 ISO-NE	Govs 2 GW Overlay	Govs 4 GW Overlay	Govs 8 GW Overlay
New Brunswick- New England	1000	1000	1000	1000
Orrington-South	1200	2500	5500	6100
Surowiec-South	1150	2100	5200	5800
Maine-NH	1450	2700	5700	6400
North-South	2700	3800	6800	7400
Boston Import	4900	4900	4900	4900
SEMA	No Limit	No Limit	No Limit	No Limit
SEMARI	3300	4200	6500	6500
East - West	3500	4300	7900	8600
West - East		4400	5100	5800
CT Import	3600	5300	7700	8200
CT Export		4200	4900	5400
Southwest Connecticut Import	3650	3650	3650	3650
Norwalk–Stamford	1650	1650	1650	1650
Cross-Sound Cable (Export)	330	330	330	330
Cross-Sound Cable (Import)	346	346	346	346
NY–NE Summer	1525	1,525	1,525	1,525
NY–NE Winter	1600	1,600	1,600	1,600
NE–NY Summer	1200	1,200	1,200	1,200
NE–NY Winter	1325	1,325	1,325	1,325
HQ–NE (Highgate)	200	200	200	200
HQ–NE (Phase II)	1800	1,800	1,800	1,800
Note: The Transfer Capability of the HVDC in 2 GW case (Highland – Mystic) and 4 GW and 8 GW case (Keswick – Millbury) is not counted in this table				

Several elements need to be defined for each of the interface:

- Source
- Sink
- Contingencies
- Monitoring Elements

The ATC module increases power transfers from predefined Source to Sink until one of the monitoring elements reaches its limit. Normal Line Rating is respected for pre-contingency and Long Term Emergency (LTE) rating is respected for post-contingency. Once any of the monitored transmission elements reaches its limit during the power transfer, the simulation stops and the corresponding interface flow is the interface limit.

2.3.9.6 Base Case - 2019 ISO-NE System

The transmission system used as a base case for the NEWIS is the one developed for the 2009 NERC Multi-regional Modeling Working Group (MMWG) Library consisting of all projects in-service across the entire Eastern Interconnection by 2020[66]. The 2019 ISO-NE system includes the existing transmission system, as well as projects listed as Planned or Under Construction (has Proposed Plan Application approval, Section I.3.9 of the ISO Tariff) on the RSP09 Transmission Project Listing.[67] The major projects included in the model are:

- Maine Power Reliability Program
- New England East West Solution
- Vermont Southern Loop Project
- Central/Western Mass Upgrades
- Greater Rhode Island Transmission Improvements
- Bangor Hydro Downeast Reliability Improvements
- National Grid Worcester Cable

[66] ISO-NE did not have any transmission projects listed in RSP09 that have an in-service date of after 2019, so the 2020 model developed for MMWG has the same topology as a 2019 system only with increased load due to load growth.

[67] RSP09 Transmission Project Listing can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2009/index.html

- Substation Improvements or Additions
- ME – Keene Rd Substation – New 345/115 Autotransformer
- ME – South Gorham Substation – New 345/115 Autotransformer
- NH – Comerford Substation – New Reactive Devices
- MA – West Amesbury Substation – New 345/115 Substation
- MA – Edgar Substation – New 115 kV Reactors
- MA – Wachusett Substation – New 345/115 Autotransformer
- CT – Broadway Substation – 2 New 115/13.8 Transformers
- CT – Union Substation – New 115/13.8 Substation
- All future Queue Generation Projects that had PPA approval (Section I.3.9) as of May 2009

In the 2019 ISO-NE system (Figure 2–22), the following counties: northern Somerset, northern Oxford, Aroostook and Washington Counties in northern Maine are considered part of New Brunswick, Area 105. These counties make up a part of the region with excellent onshore wind resource. Main Public Service territory consisting of Aroostook and Washington Counties are currently served radially from New Brunswick. No wind power projects in the Partial Queue scenario are located in these counties; however, these northernmost areas are tied into the rest of the regional transmission system for all of the non-base case transmission overlays used for the NEWIS, allowing access to wind resources located there.

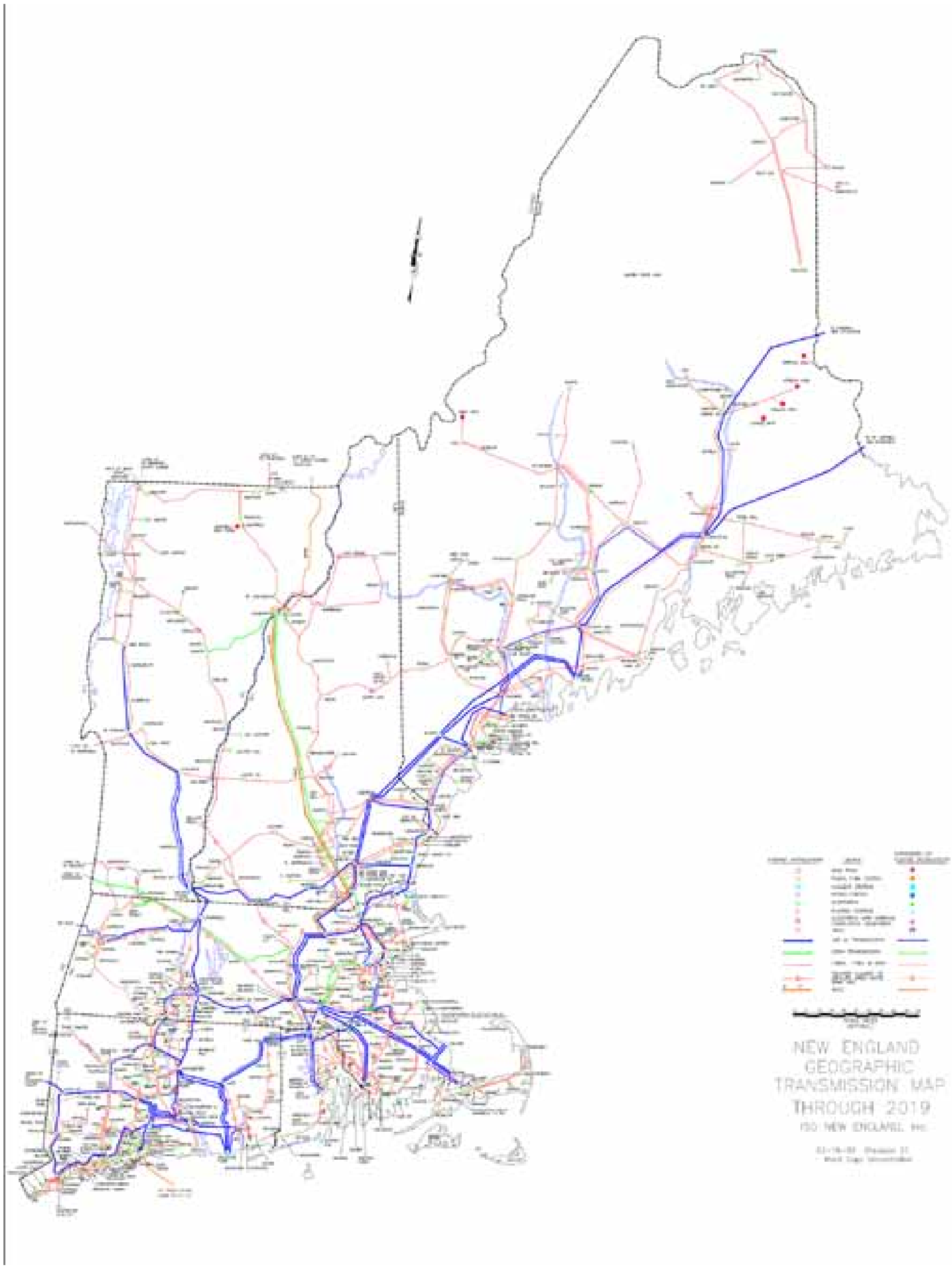


Figure 2–22 2019 ISO-NE System

Since the 2019 ISO-NE system is a composite of the existing transmission system and near-term transmission projects it was matched with the Partial Queue wind scenario, which similarly includes wind projects either already built or likely to be developed in the near-term.

2.3.9.7 Governors' 2 GW Overlay

The Governors' 2 GW overlay features the identical architecture as the 2 GW onshore overlay used in the Governor's Study, elements of which are broken down in Table 2–22 below.

Table 2–22 Breakdown of 2 GW transmission overlay

CATEGORY DESCRIPTION	SUB-CATEGORY DESCRIPTION	CIRCUIT MILES	# OF SUBSTATIONS
TRANSMISSION	1. 345kV AC Backbone	355	
	2. 345kV AC / HVDC Backbone	240	
	3. 345kV Local Loops	645	
	4. 115kV Reinforcements	545	
	TOTAL	1785	
SUBSTATION	1. 345kV AC Backbone		3
	2. 345kV AC / HVDC Backbone		3
	3. 345kV Local Loops		8
	4. 115kV And 69kV Reinforcements		20
	TOTAL		34

The Governors' 2 GW overlay consists of the following potential transmission and related system upgrades relative to the 2019 ISO-NE system:

- 345kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind
- Single-circuit overhead 345 KV backbone, central ME-Millbury-Manchester, and single-circuit overhead 345 kV backbone to high-voltage direct-current (HVDC) submarine cable, ME-Boston to move energy to load centers
- Upgraded coastal substations in MA and RI with reinforced 115 kV to connect offshore wind
- Other small disbursed inland and offshore wind connect to existing 115 kV substations
- 1,785 miles of total potential new transmission circuit

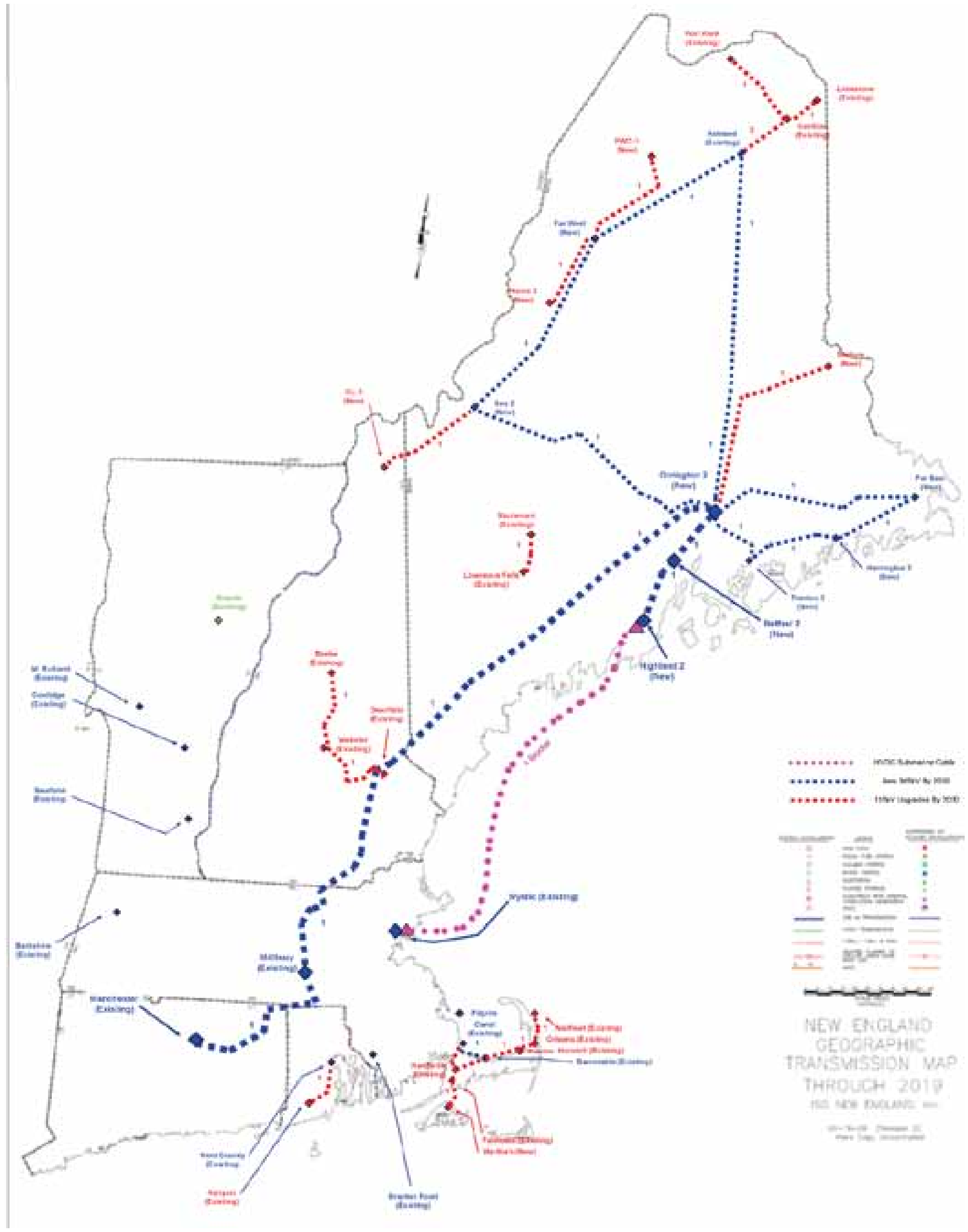


Figure 2–23 Governors' 2 GW overlay used for NEWIS Full Queue and 14% Wind Penetrations Scenarios

Figure 2–23 above is a schematic of the Governors' 2 GW overlay, this overlay was used as the transmission system for the Full Queue wind scenario and the 14% total energy wind scenarios, which include regional wind penetrations greater than 7 GW. As this is the only of the three overlays that does not feature transmission upgrades between Canal Substation and Millbury Substation in southeastern Massachusetts, it highlights constraints and operational issues in that load zone resulting from offshore wind development in Massachusetts and Rhode Island. Offshore wind development in this area includes a 460 MW wind power project which has received I.3.9 approval and therefore is considered a near-term project. Hypothetical local transmission loops acts as conduits for wind buildout in northern Maine, and thus would require integration of these areas into the jurisdiction of the Federal Energ Regulatory Commission (FERC).

2.3.9.8 Governors' 4 GW Overlay

The Governors' 4 GW overlay is a composite of the following transmission designs from the Governor's Study: 1) The 4 GW onshore overlay, which serves as the primary overlay architecture, 2) a 1,500 MW New Brunswick interconnection, and 3) additional transmission in SEMA to ensure deliverability of potential offshore in Massachusetts and Rhode Island, which is a feature of the 8 GW overlay in the Governor's Study. Of the two voltage class options outlined for this scenario in the Governor's Study, 500 kV loops were selected for use. Table 2–23 is a breakdown of all transmission and substation upgrades featured in this overlay.

Table 2–23 Breakdown of 4 GW transmission overlay

CATEGORY DESCRIPTION	SUB-CATEGORY DESCRIPTION	CIRCUIT MILES	# OF SUBSTATIONS
500kV BACKBONE LOOPS			
TRANSMISSION	1. 500kV Backbone Loops	2750	
	2. 345kV Local Loops	480	
	3. 115kV Reinforcements	465	
	SUBTOTAL	3695	
SUBSTATION	1. 500kV Backbone Loops		15
	2. 345kV Local Loops		12
	3. 115kV And 69kV Reinforcements		14
	SUBTOTAL		41
1500 MW New Brunswick Interchange			
TRANSMISSION	1. +/- 450kV HVDC Bi-Polar O/H Backbone	400	
	SUBTOTAL	400	
SUBSTATION	1. +/-450kV, 1500 MW HVDC Bi-Polar Terminal		1
	TOTAL	4095	42

The Governors' 4 GW overlay consists of the following potential transmission and related system upgrades relative to the 2019 ISO-NE system:

- 345kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind
- Dual-circuit overhead 500 kV backbones through most of interior New England
- Upgraded coastal substations with reinforced 345 kV and 115 kV to connect offshore wind in MA, RI
- Other small disbursed inland and offshore wind connect to existing 115 kV substations
- Added 345 kV line from SEMA to Millbury (element from 8 GW overlay) to connect offshore wind in MA & RI
- A New Brunswick interconnection consisting of a +/- 450 kV HVDC overhead line capable of transporting 1,500 MW of power from the Keswick area of New Brunswick south via the northern Maine border to Millbury, Massachusetts.
- 4,095 (3,695w/o NB interconnect) miles of total potential new transmission circuit

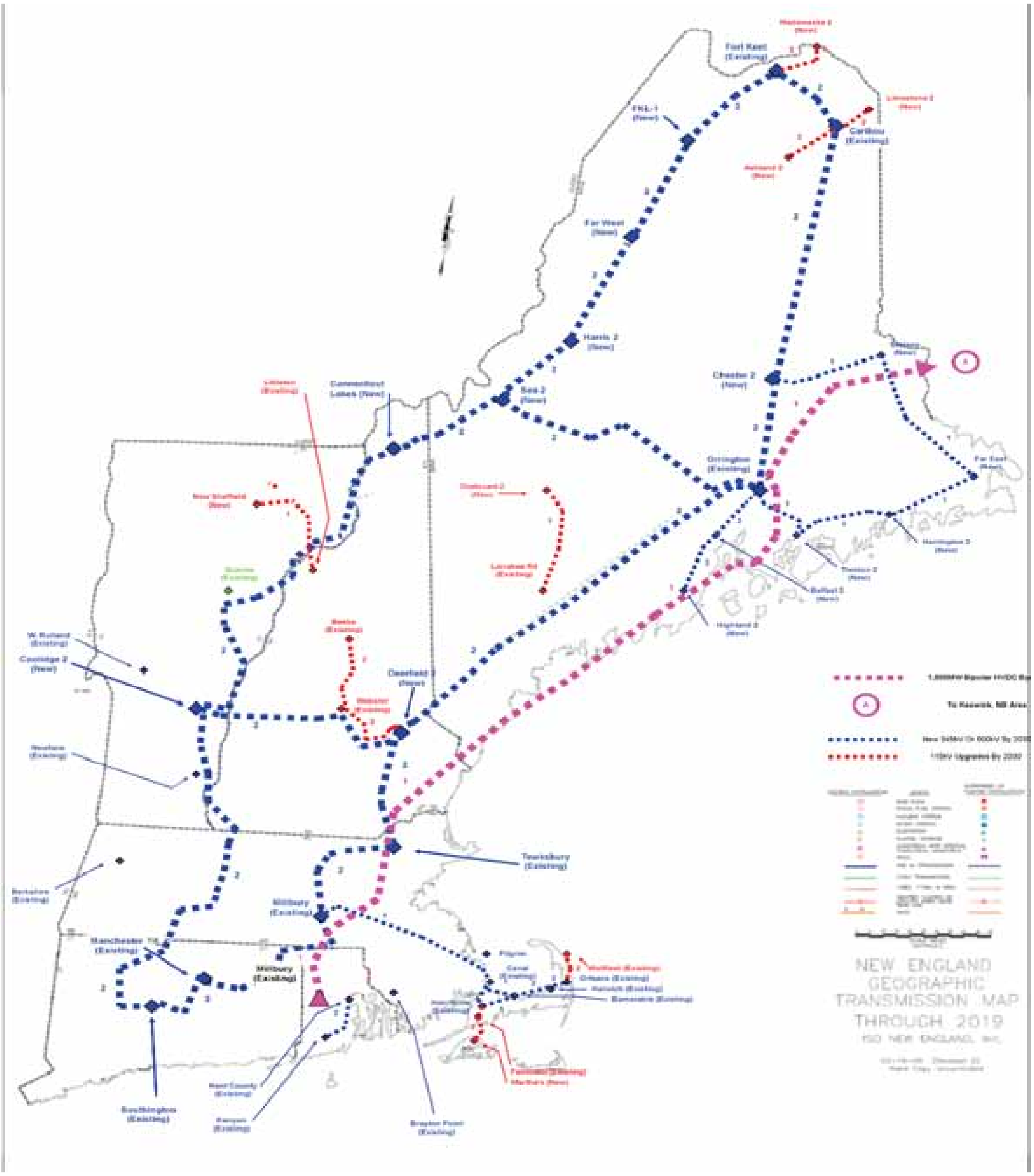


Figure 2–24 Governors' 4 GW overlay used for NEWIS 20% Wind Penetrations Scenarios

Figure 2–24 is a schematic of the Governors’ 4 GW overlay. This overlay was used as the transmission system for the 20% regional energy scenarios, representing regional wind penetrations approaching 10 GW. Local loops featured for northern Maine in the 2 GW overlay are upgraded to backbone loops to deliver up to 7 GW of onshore wind hypothesized for the state (Best Onshore 20% case). Also included in the overlay is a 1500 MW HVDC line between the Maritimes (Keswick, NB) and Millbury, MA. Such an HVDC line would facilitate transfer of power between the Maritimes and ISO-NE (viz-a-viz the Maritimes Wind Scenarios).

2.3.9.9 Governors' 8 GW Overlay

The 8 GW overlay is architecturally identical to the 8 GW Governor's Study overlay, with the addition of the 1,500 MW New Brunswick interconnection. Of the two voltage class options outlined for this scenario in the Governor's Study, 500 kV loops were selected for use. Table 2–24 is a breakdown of all transmission and substation upgrades featured in this overlay.

Table 2–24 Breakdown of 8 GW transmission overlay

CATEGORY DESCRIPTION	SUB-CATEGORY DESCRIPTION	CIRCUIT MILES	# OF SUBSTATIONS
500kV BACKBONE LOOPS			
TRANSMISSION	1. 500kV Backbone Loops	2740	
	2. 345kV Local Loops	1395	
	3. 115kV Reinforcements	185	
	SUBTOTAL	4320	
SUBSTATION	1. 500kV Backbone Loops		10
	2. 345kV Local Loops		29
	3. 115kV And 69kV Reinforcements		5
	SUBTOTAL		44
1500 MW New Brunswick Interchange			
TRANSMISSION	1. +/- 450kV HVDC Bi-Polar O/H Backbone	400	
	SUBTOTAL	400	
SUBSTATION	1. +/-450kV, 1500 MW HVDC Bi-Polar Terminal		1
	TOTAL	4720	45

The 8 GW overlay consists of the following potential transmission and related system upgrades relative to the 2019 ISO-NE system:

- 345kV and 115 kV local loops and radials (NH and ME) to connect on and offshore wind
- Dual-circuit overhead 500 kV backbones through most of interior New England
- Upgraded coastal substations with reinforced 500 kV, 345 kV and 115 kV to connect offshore wind in MA, RI

- Other small disbursed inland and offshore wind connect to existing 115 kV substations
- A New Brunswick interconnection consisting of a +/- 450 kV HVDC overhead line capable of transporting 1,500 MW of power from the Keswick area of New Brunswick south via the northern Maine border to Millbury, Massachusetts.
- 4,720 (4,320 w/o NB interconnection) miles of total potential new transmission circuit

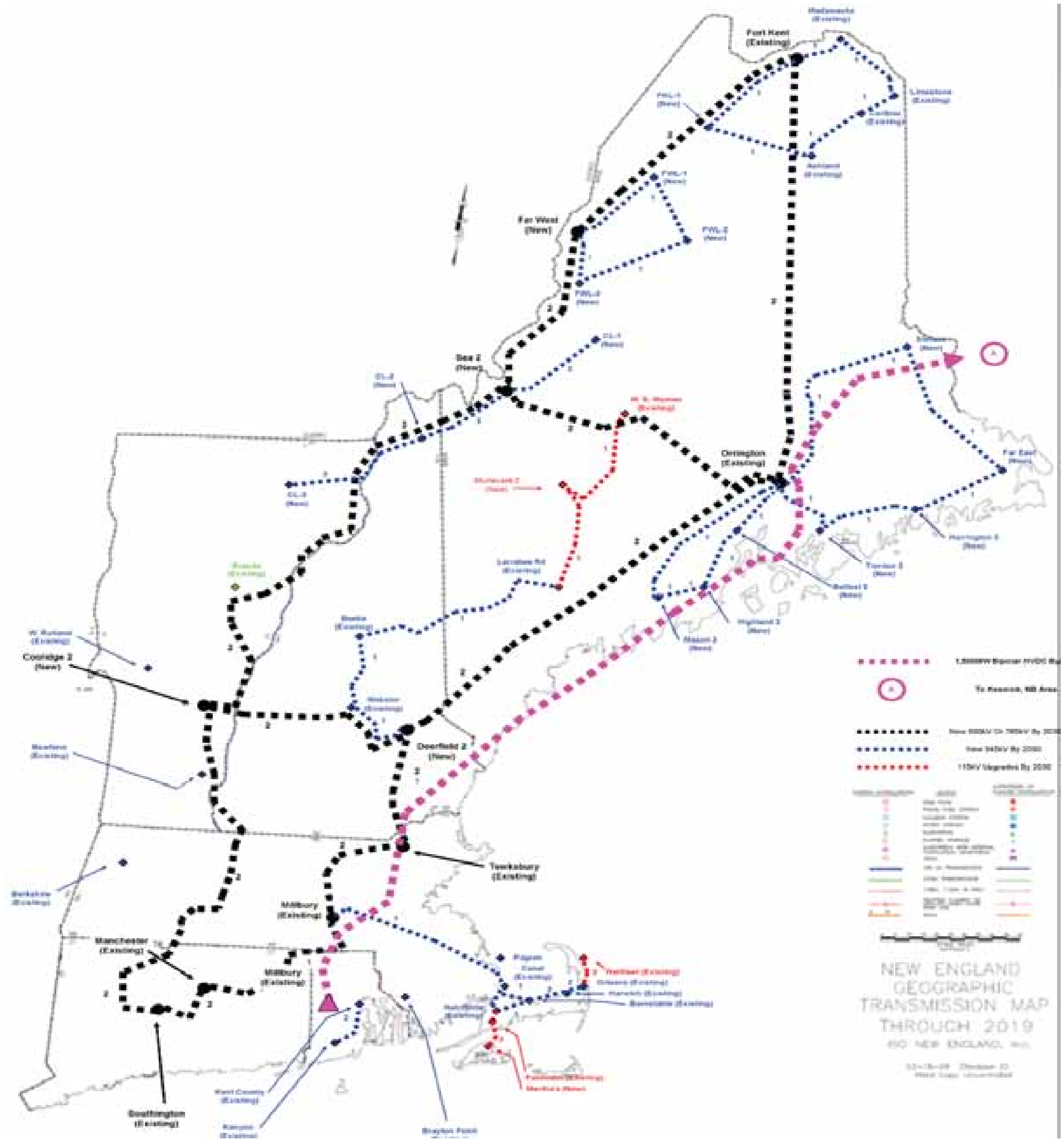


Figure 2–25 Governors' 8 GW overlay used for NEWIS 12 GW Wind Penetrations Scenarios

Figure 2–25 is a schematic of the 8 GW overlay. The 8 GW transmission overlay was used for the 12 GW nameplate capacity scenarios.

2.4 Analytical Methods

The primary objective of this study was to identify and quantify any system performance or operational problems with respect to load following, regulation, operation during low-load periods, etc. Three primary analytical methods were used to meet this objective; statistical analysis, hourly production simulation analysis, and reliability analysis. While the NEWIS tested the feasibility of wind integration under hypothetical future scenario analyses developed for the study, real-world operating and system performance conditions can vary significantly from these types of hypothesized scenarios.

Statistical analysis was used to quantify variability due to system load, as well as wind generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The power grid already has significant variability due to periodic and random changes to system load. Wind generation adds to that variability, and increases what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind generation for each scenario. The statistical analysis also characterized the forecast errors for wind generation.

Production simulation analysis with General Electric's Multi-Area Production Simulation software (GE MAPS) was used to evaluate hour-by-hour grid operation of each scenario for 3 years with different wind and load profiles. The production simulation results quantified numerous impacts on grid operation including the primary targets of investigation:

- Amount of maneuverable generation on-line during a given hour, including its available ramp-up and ramp-down capability to deal with grid variability due to load and wind
- Effects of day-ahead wind forecast alternatives in unit commitment
- Changes in dispatch of conventional generation resources due to the addition of new renewable generation
- Changes in transmission path loadings

Other measures of system performance were also quantified, including:

- Changes in emissions (NOx, SOx, CO2) due to renewable generation
- Changes in energy costs and revenues associated with grid operation, and changes in net cost of energy
- Changes in use and economic value of energy storage resources

Reliability analysis involved loss of load expectation (LOLE) calculations for ISO-NE system using General Electric's Multi-Area Reliability Simulation program, (GE MARS). The analysis quantified the impact of wind generation on overall reliability measures, as well as the capacity values of the wind resources.

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics and production simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind generation into the ISO-NE power grid.

3 Statistical Analysis and Characterization of Study Data

Wind generation is variable across time scales ranging from seconds to seasons, and cannot be perfectly forecast over any horizon. Because Balancing Area load also exhibits variability and uncertainty across many operational time frames, the impacts of wind generation on ISO-NE operations are a function of the degree to which this variability and uncertainty increases the overall variability and uncertainty of the net load.

The general purpose of the analysis in this section is to convey a familiarity with the chronological load and wind data that are the primary inputs to the technical analysis described in later sections. It is generally not possible to extract quantitative conclusions about operating impacts directly from statistics of wind and load data. While certain features may stand out from the perspective of system operations – such as lower net loads during off-peak hours – a range of other factors must be considered to determine the magnitude of the impact. Production simulations take a great number of these other factors into account as they seek to mimic the actual operation of the system against the array of operating constraints, and therefore are the better framework for drawing operational conclusions

Wind generation scenarios defined for the study are shown in Table 3–1. As described in Section 2.1, the scenarios were constructed by selecting grid cells from the NEWRAM. Individual cells were then grouped into "plants," for which chronological production data at ten-minute resolution over the calendar years 2004, 2005, and 2006 were extracted.

In the MAPS production simulations, individual plants were assigned to existing or planned network buses in the ISO-NE model. In this statistical analysis and characterization, the aggregate production, i.e. the total generation of all plants in each scenario, is analyzed.

As described in Section 2.2.1, ISO-NE load data at 10-minute resolution for the same calendar years as the wind production data was obtained. ISO-NE load data at 1-minute resolution for a different year was also used for analysis in the project, but is not reported on in this section. An extrapolation algorithm developed with guidance from ISO-NE staff was applied to the load data sets to make them representative of the future study year.

Table 3–1 Wind scenario description

Scenario	Installed Capacity (MW)
20% Queue + Best Sites Onshore	9,779
9% Full Queue	4,169
2.5% Partial Queue	1,140
20% Queue + Best Sites Offshore	8,294
20% Queue + Balance Case	8,798
20% Queue + Best Sites by State	10,235
20% Queue + Best Sites Maritimes	8,956
14% Queue + Best Sites Onshore	6,746
14% Queue + Best Sites Offshore	6,130
14% Queue + Balance Case	6,306
14% Queue + Best Sites by State	7,252
14% Queue + Best Sites Maritimes	6,394

Table 3–2 summarizes the ISO-NE load for 2004, 2005, and 2006 patterns – scaled for the study year – and hourly wind generation for each scenario. Load net of wind generation is summarized in Table 3–3. Of note in both tables are the aggregate annual energy statistics, the contribution of wind energy during peak load hours for each scenario, and the minimum net load. For one layout alternative at 20% penetration (the Best By State layout), the minimum net load is reduced from about 10 GW to less than 3 GW, or about 10% of peak load.

Operationally, the net of load and wind generation (i.e., the net load) will drive the decisions and algorithms for deployment of controllable resources (e.g. conventional generating units, energy transactions with neighboring markets and areas, and demand response). The net load analysis does not consider energy transactions with neighboring markets and systems, so the minimum hourly net load values for each scenario cannot be used directly to assess implications for the ISO-NE generation fleet. The price of the excess energy during these periods would be very low, and therefore presumably attractive to outside purchasers; energy sales could add significantly to the demand served by ISO-NE resources.

Table 3–4 documents the maximum and minimum net load hours by year. The minimum net load hour mentioned above (i.e. changing the minimum load from 10 GW to less than 3 GW) occurs for the “20% Queue + Best Sites by State” scenario for load and wind generation based on calendar year 2006 patterns. With patterns from the other calendar years, the minimum net load for this scenario is substantially higher (4997 MW for 2004, and 4228 MW for 2005). It is interesting to note that these absolute minimum net loads do not occur during the same hour of the year, or even in the same season (April for 2004, late October, but different days and hours for 2005 and 2006).

Table 3–2 Summary Statistics for Projected ISO-NE 2020 Load and Wind Generation Scenarios

Scenario	Maximum (MW)	Minimum (MW)	Average (MW)	Std. Deviation (MW)	Average Annual Energy (GWh)
Load	31,572	10,250	18,383	3,810	161,181
2.5% Partial Queue	1,055	0	422	266	3,697
9% Full Queue	3,824	2	1,416	898	12,414
14% Queue + Best Sites Onshore	6,364	2	2,380	1,555	20,872
14% Queue + Best Sites Offshore	5,665	4	2,333	1,403	20,459
14% Queue + Balance Case	5,825	9	2,331	1,384	20,440
14% Queue + Best Sites by State	6,731	7	2,355	1,484	20,649
14% Queue + Best Sites Maritimes	5,849	29	2,317	1,289	20,312
20% Queue + Best Sites Onshore	8,973	4	3,313	2,186	29,046
20% Queue + Best Sites Offshore	7,505	4	3,252	2,021	28,512
20% Queue + Balance Case	7,827	43	3,944	1,968	28,151
20% Queue + Best Sites by State	9,264	16	3,273	2,067	28,701
20% Queue + Best Sites Maritimes	8,198	57	3,322	1,872	29,125

Table 3–3 Load and Net Load Statistics over all 3 Years of Data

Scenario - Net Load	Maximum (MW)	Minimum (MW)	Average (MW)	Std. Deviation (MW)	Average Annual Energy (GWh)
Load	31,572	10,250	18,383	3,810	161,181
2.5% Partial Queue	31,141	9,749	17,961	3,804	157,484
9% Full Queue	30,617	7,712	16,967	3,863	148,766
14% Queue + Best Sites Onshore	30,333	5,865	16,002	4,044	140,309
14% Queue + Best Sites Offshore	30,404	5,875	16,049	3,971	140,722
14% Queue + Balance Case	30,235	5,748	16,052	3,942	140,740
14% Queue + Best Sites by State	30,454	5,267	16,028	4,003	140,532
14% Queue + Best Sites Maritimes	30,478	6,043	16,066	3,954	140,869
20% Queue + Best Sites Onshore	30,095	3,468	15,070	4,304	132,135
20% Queue + Best Sites Offshore	30,341	4,039	15,131	4,191	132,669
20% Queue + Balance Case	29,923	4,015	15,172	4,108	133,029
20% Queue + Best Sites by State	30,180	2,783	15,109	4,228	132,479
20% Queue + Best Sites Maritimes	30,284	4,130	15,061	4,143	132,055

Table 3–4 Maximum and Minimum Net Load by Pattern Year and Hour

	Maximum (MW)	Maximum Hour	Minimum (MW)	Minimum Hour
Scenario - Net Load - 2004 Patterns				
Load	31,572	8/31/04 16:00	12,075	6/1/04 5:00
2.5% Partial Queue	31,123	8/31/04 16:00	11,456	4/19/04 5:00
9% Full Queue	30,617	8/4/04 17:00	9,011	4/19/04 5:00
14% Queue + Best Sites Onshore	30,333	8/4/04 17:00	6,817	4/19/04 5:00
14% Queue + Best Sites Offshore	30,404	8/4/04 18:00	7,181	4/19/04 5:00
14% Queue + Balance Case	30,235	8/4/04 17:00	7,149	4/19/04 5:00
14% Queue + Best Sites by State	30,454	8/4/04 16:00	7,088	4/20/04 3:00
14% Queue + Best Sites Maritimes	30,478	8/4/04 17:00	7,376	4/20/04 3:00
20% Queue + Best Sites Onshore	30,095	8/4/04 17:00	4,438	4/20/04 3:00
20% Queue + Best Sites Offshore	30,341	8/4/04 18:00	5,349	4/19/04 5:00
20% Queue + Balance Case	29,923	8/4/04 17:00	5,343	4/19/04 5:00
20% Queue + Best Sites by State	30,180	8/4/04 16:00	4,997	4/20/04 3:00
20% Queue + Best Sites Maritimes	30,284	8/4/04 17:00	5,236	4/20/04 3:00
Scenario - Net Load - 2005 Patterns				
Load	31,545	7/29/05 18:00	10,885	6/1/05 7:00
2.5% Partial Queue	31,141	7/29/05 18:00	10,438	11/8/05 7:00
9% Full Queue	30,270	7/29/05 18:00	8,481	11/8/05 7:00
14% Queue + Best Sites Onshore	29,719	7/29/05 18:00	6,582	5/12/05 7:00
14% Queue + Best Sites Offshore	29,564	7/21/05 19:00	6,893	11/8/05 7:00
14% Queue + Balance Case	29,272	7/28/05 20:00	6,851	11/8/05 7:00
14% Queue + Best Sites by State	29,567	7/21/05 18:00	6,477	11/8/05 7:00
14% Queue + Best Sites Maritimes	30,178	7/29/05 18:00	6,441	11/8/05 6:00
20% Queue + Best Sites Onshore	29,542	7/28/05 20:00	4,334	4/3/05 6:00
20% Queue + Best Sites Offshore	29,313	7/21/05 16:00	5,130	11/8/05 8:00
20% Queue + Balance Case	28,990	7/28/05 20:00	5,195	4/3/05 6:00
20% Queue + Best Sites by State	29,024	7/21/05 18:00	4,228	10/25/05 8:00
20% Queue + Best Sites Maritimes	30,054	7/29/05 18:00	4,133	11/8/05 6:00

	Maximum (MW)	Maximum Hour	Minimum (MW)	Minimum Hour
Scenario - Net Load - 2006 Patterns				
Load	31,557	7/29/06 16:00	10,250	4/12/06 7:00
2.5% Partial Queue	30,785	7/29/06 19:00	9,749	4/13/06 6:00
9% Full Queue	30,107	7/30/06 17:00	7,712	4/13/06 6:00
14% Queue + Best Sites Onshore	29,914	7/30/06 17:00	5,865	4/13/06 6:00
14% Queue + Best Sites Offshore	30,103	7/30/06 17:00	5,875	4/13/06 6:00
14% Queue + Balance Case	29,890	7/30/06 17:00	5,748	4/13/06 6:00
14% Queue + Best Sites by State	29,828	7/30/06 17:00	5,267	10/29/06 6:00
14% Queue + Best Sites Maritimes	29,212	7/13/06 20:00	6,043	4/13/06 6:00
20% Queue + Best Sites Onshore	29,710	7/30/06 17:00	3,468	10/21/06 7:00
20% Queue + Best Sites Offshore	30,102	7/30/06 17:00	4,039	4/13/06 6:00
20% Queue + Balance Case	29,675	7/30/06 17:00	4,015	4/13/06 6:00
20% Queue + Best Sites by State	29,738	7/30/06 17:00	2,783	10/29/06 6:00
20% Queue + Best Sites Maritimes	28,821	7/13/06 18:00	4,130	4/13/06 6:00

Maximum net loads are also of interest. Looking only at the single hour maximum net load hour, it can be seen from the tables that wind generation in all of the scenarios reduces the ISO-NE peak load. The amount of this reduction varies by scenario and year, as would be expected from the differing geographic makeup of each scenario and the variability between years in terms of both load and wind resources. Scenarios with a greater proportion of offshore wind resources, for example, have a higher probability of significant production during the single peak demand hour due to the nature and timing of the sea breezes.

It may be tempting to draw some conclusions about the scenario capacity values from the table. However, the focus on a single hour is not appropriate and is potentially misleading. The capacity value analysis described later in the report will consider not just these single hours, but all hours of an annual period along with the important system risks to determine wind generation capacity contributions with a much higher degree of confidence. The rigorous analytical methodology used in this study to determine the capacity value of each wind scenario is much less prone to being influenced by a single hour of the chronological data.

The initial part of this section focuses on the variability of wind generation as defined by the study scenarios and how it combines with the inherent variability of ISO-NE load. The analysis first looks at hourly data over the entire three years of the available wind and load data. Variability and uncertainty are then examined with the 10-minute interval data. Finally, the uncertainty and error characteristics of various forecasts available for the chronological wind production data are analyzed including the day-ahead and 4-hour ahead forecasts that are part of the NEWRAM. Other techniques important to the analysis presented later in the report, such as persistence forecasts, are also examined.

The analysis here is conducted on an aggregate basis for the entire footprint; that is, the total generation for each time interval (10-minute, 1-hour, as appropriate) is considered, independent of where the individual virtual plants may be located. Differences stemming from alternate layouts of wind generation for scenarios of similar penetration are used to compare locational effects. The transmission infrastructure assumed for the study was not a factor in this analysis; the views of the data here assume a zero-impedance “copper sheet” network for transporting energy from sources to loads.

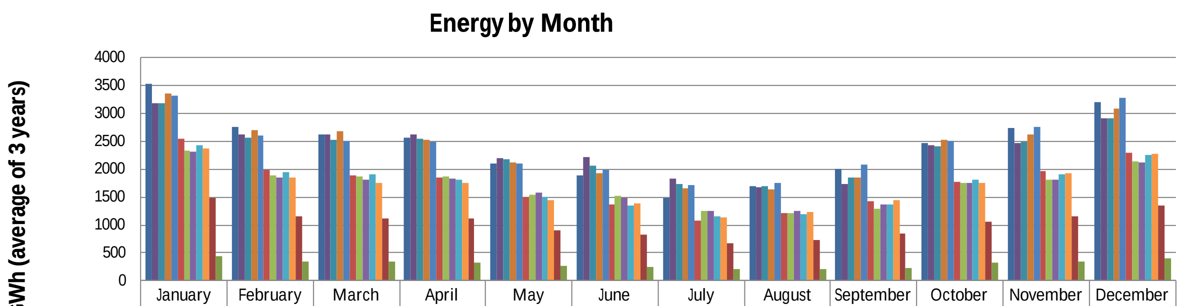
3.1 Wind Generation Variability

The time horizons for which wind generation variability is important for power system operations range from tens of seconds to seasons. Over shorter horizons, the variability appears as almost random due to the extremely large number of factors that can influence production over this time frame. Over longer horizons, such as weeks or seasons, patterns reflecting the underlying meteorological drivers for wind generation can usually be discerned. Over longer time scales such as years, varying production is driven by even larger meteorological patterns that were first identified a few decades ago, e.g. the El Nino/La Nina cycle in the Pacific, and closer to New England, the North Atlantic Oscillation.

3.1.1 Variability – Energy Production

The energy delivery by month for all wind generation scenarios is shown in Figure 3–1. The monthly values reflect the average of all three years of production data in the NEWRAM dataset. The bias toward production in the winter months is clearly seen, as well as the minimum production over the summer (i.e. peak load) months.

Another view of the same data is found in Figure 3–2, with the energy production averaged by seasons rather than individual months.



	January	February	March	April	May	June	July	August	September	October	November	December
20% Queue + Best Sites Onshore	3529	2760	2620	2561	2103	1882	1493	1693	1998	2462	2743	3202
20% Queue + Best Sites Offshore	3174	2616	2617	2628	2196	2215	1835	1675	1743	2431	2462	2919
20% Queue + Balanced Case	3174	2569	2534	2544	2175	2069	1731	1703	1845	2401	2491	2916
20% Queue + Best Sites by State	3354	2696	2674	2532	2119	1932	1652	1645	1850	2531	2622	3094
20% Queue + Best Sites Maritimes	3321	2605	2510	2483	2098	1992	1715	1763	2090	2515	2764	3268
14% Queue + Best Sites Onshore	2543	1987	1896	1845	1508	1361	1071	1213	1419	1767	1964	2298
14% Queue + Best Sites Offshore	2326	1888	1863	1869	1550	1524	1252	1205	1294	1748	1808	2134
14% Queue + Balanced Case	2306	1857	1819	1837	1573	1480	1248	1255	1370	1747	1820	2129
14% Queue + Best Sites by State	2435	1941	1899	1817	1512	1356	1154	1198	1365	1816	1908	2247
14% Queue + Best Sites Maritimes	2365	1843	1761	1752	1449	1379	1140	1225	1449	1749	1925	2275
9% Full Queue	1478	1164	1112	1110	901	831	666	736	845	1065	1156	1352
2.5% Partial Queue	434	349	345	334	271	246	208	212	237	327	337	397

Figure 3–1 Average monthly energy delivery by wind generation scenario

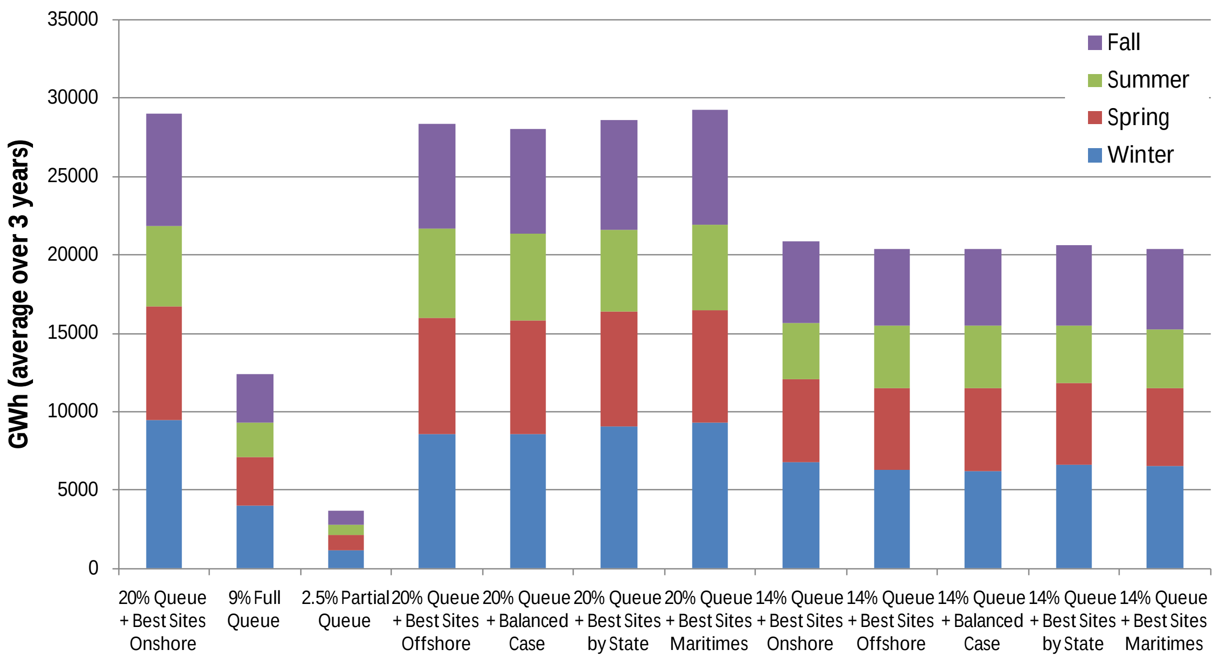
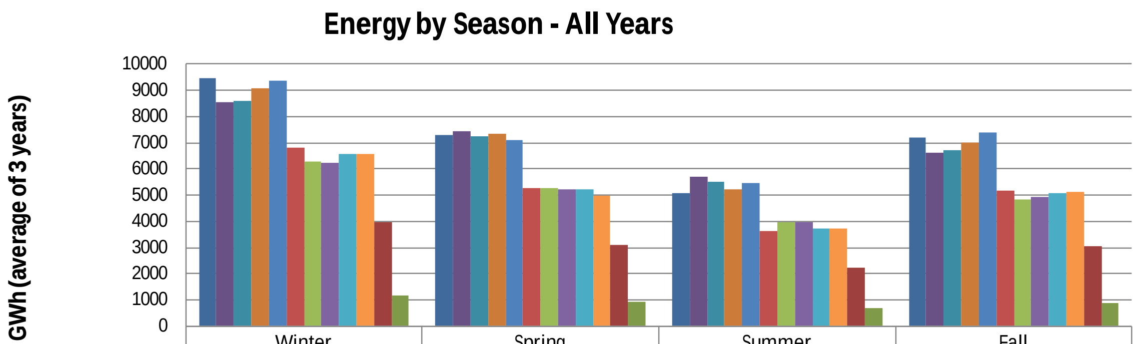


Figure 3–2 Average energy delivery by season for each wind generation scenario

On a seasonal basis, and averaged over all three years of data, the highest production of the winter months is still evident (Figure 3–3). Seasonal contributions as a percentage of the total are shown for all scenarios in Figure 3–4.



	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	9474	7284	5068	7203
20% Queue + Best Sites Offshore	8556	7441	5725	6636
20% Queue + Balanced Case	8580	7253	5504	6736
20% Queue + Best Sites by State	9070	7325	5229	7003
20% Queue + Best Sites Maritimes	9353	7092	5470	7369
14% Queue + Best Sites Onshore	6805	5249	3645	5150
14% Queue + Best Sites Offshore	6268	5281	3980	4850
14% Queue + Balanced Case	6255	5229	3983	4937
14% Queue + Best Sites by State	6590	5228	3708	5089
14% Queue + Best Sites Maritimes	6565	4962	3744	5123
9% Full Queue	3986	3123	2232	3066
2.5% Partial Queue	1167	950	667	901

Figure 3–3 Wind energy production by season and scenario, averaged over 3 years

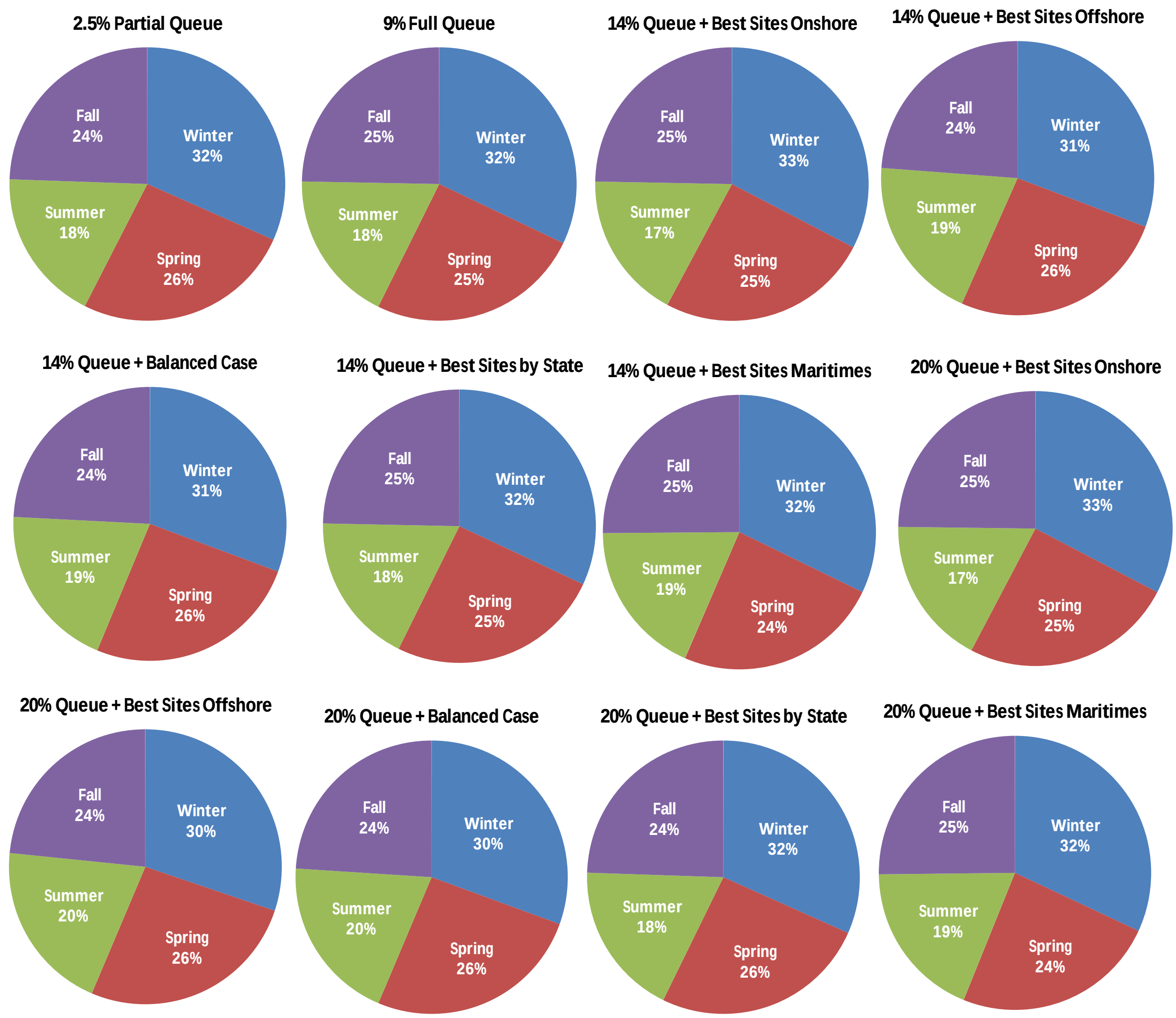


Figure 3–4 Seasonal energy contribution for wind generation scenarios

In general, the scenarios are quite similar with respect to monthly and seasonal energy production characteristics. Highest production occurs during the winter season, with the lowest production in summer. The composite nature of each scenario (different mixture of on- and off-shore plants, differing geographic characteristics, etc.) and averaging production over three years of annual hourly data are likely responsible for attenuating the contrasts regarding energy production. All of the large scenarios (14% and 20% energy) have the 9% Full Queue scenario in common, which is another reason for the similarities.

Examination of the wind production data on a year-by-year basis reveals some inter-annual variability. Figure 3–5 shows the variation in annual energy for each scenario for each of the three years of wind data. The “20% Queue + Best Sites Onshore” and “20% Queue +Best Sites Maritimes” scenarios show the most annual variability. Figure 3–6 shows the seasonal variation by year for these two scenarios, and shows that most of the annual variability occurs in the winter and fall seasons.

It should also be noted that the three-year record is likely insufficient for completely understanding variations in energy production between years. The large-scale weather drivers mentioned previously can be periods of many years to decades, so a sample of three years would not paint a complete picture of the expected inter-annual variability. The large scale climatological phenomena mentioned earlier have periods of several years to a decade, and sunspot cycles, also considered to influence climate, have 7 and 11 years periods. It has been speculated that at least ten years of data might be needed to develop a high degree of confidence in the long-term behavior.

Figure 3–7 through Figure 3–9 detail the energy by season and scenario for each year of the dataset.

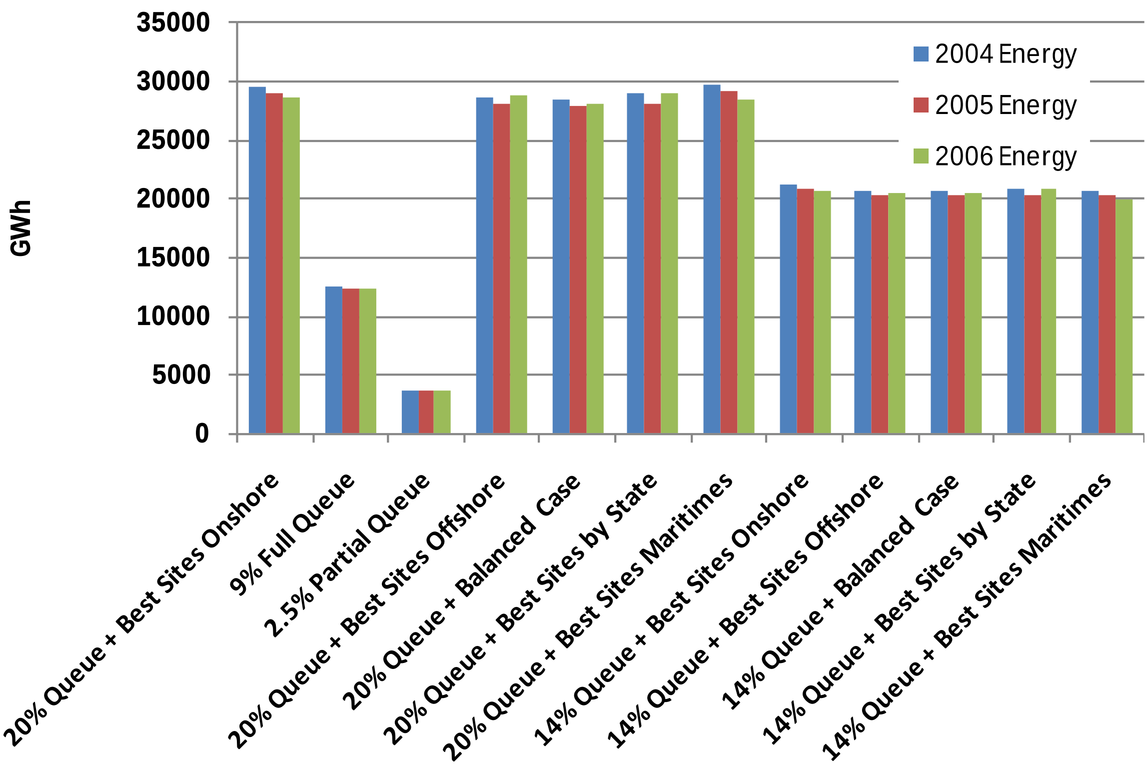


Figure 3–5 Energy delivery by year for each scenario

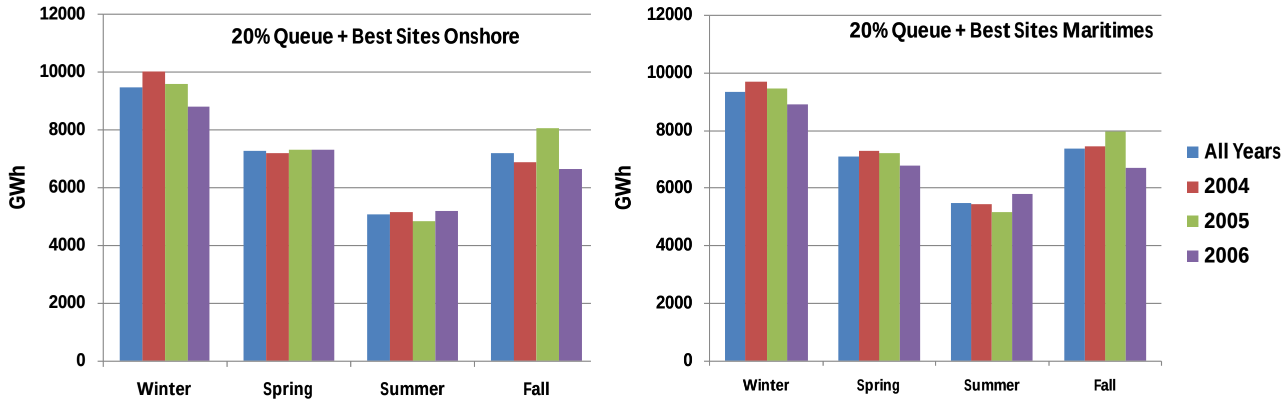
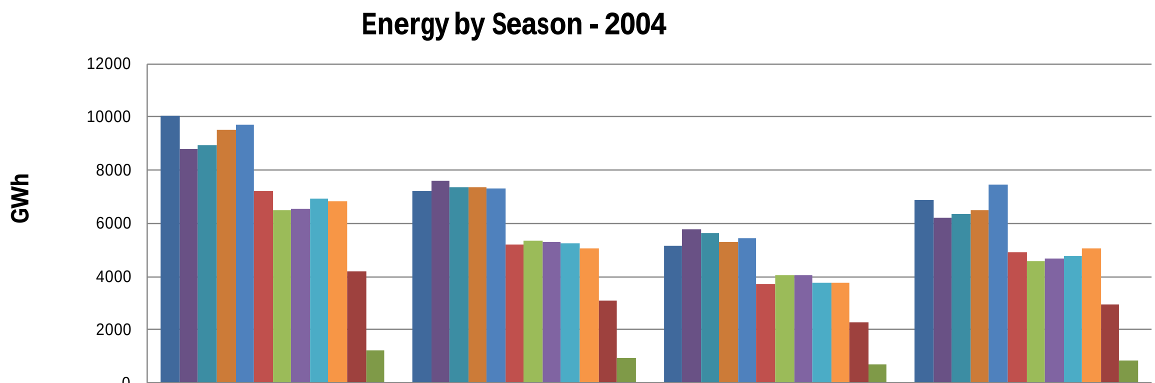
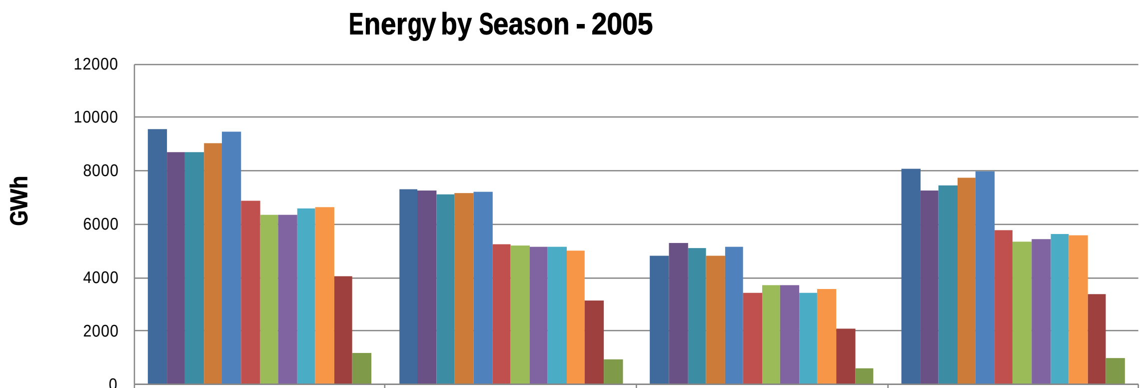


Figure 3–6 Seasonal inter-annual variability for 20% Best Sites Onshore and 20% Best Sites Maritimes scenarios



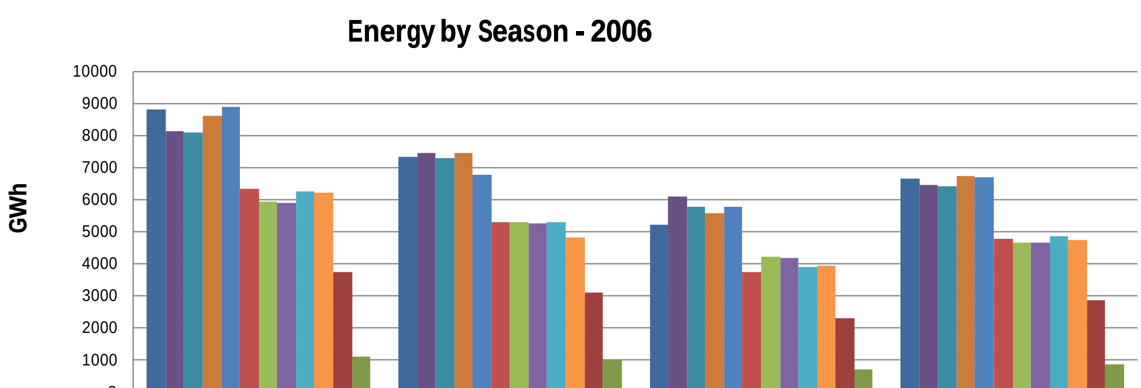
	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	10038	7200	5158	6885
20% Queue + Best Sites Offshore	8815	7613	5785	6187
20% Queue + Balanced Case	8953	7345	5612	6356
20% Queue + Best Sites by State	9536	7366	5295	6518
20% Queue + Best Sites Maritimes	9693	7288	5442	7435
14% Queue + Best Sites Onshore	7218	5185	3728	4915
14% Queue + Best Sites Offshore	6500	5358	4034	4561
14% Queue + Balanced Case	6532	5280	4066	4683
14% Queue + Best Sites by State	6941	5239	3783	4761
14% Queue + Best Sites Maritimes	6822	5072	3755	5067
9% Full Queue	4191	3109	2282	2930
2.5% Partial Queue	1230	942	695	846

Figure 3–7 2004 energy by season



	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	9576	7325	4833	8076
20% Queue + Best Sites Offshore	8720	7268	5303	7274
20% Queue + Balanced Case	8695	7131	5131	7460
20% Queue + Best Sites by State	9053	7159	4820	7761
20% Queue + Best Sites Maritimes	9474	7203	5179	7981
14% Queue + Best Sites Onshore	6880	5271	3454	5767
14% Queue + Best Sites Offshore	6372	5206	3706	5329
14% Queue + Balanced Case	6331	5165	3703	5465
14% Queue + Best Sites by State	6582	5144	3428	5640
14% Queue + Best Sites Maritimes	6641	5014	3552	5567
9% Full Queue	4034	3142	2100	3393
2.5% Partial Queue	1165	925	590	992

Figure 3–8 2005 energy by season



	Winter	Spring	Summer	Fall
20% Queue + Best Sites Onshore	8808	7327	5212	6648
20% Queue + Best Sites Offshore	8133	7442	6088	6448
20% Queue + Balanced Case	8093	7281	5768	6393
20% Queue + Best Sites by State	8622	7451	5572	6730
20% Queue + Best Sites Maritimes	8891	6783	5790	6689
14% Queue + Best Sites Onshore	6316	5290	3751	4769
14% Queue + Best Sites Offshore	5932	5279	4201	4660
14% Queue + Balanced Case	5901	5241	4180	4662
14% Queue + Best Sites by State	6248	5300	3914	4867
14% Queue + Best Sites Maritimes	6231	4800	3924	4735
9% Full Queue	3732	3119	2314	2874
2.5% Partial Queue	1106	984	715	864

Figure 3–9 2006 energy by season

3.1.2 Capacity Factor

Average capacity factor over the three years of data for each scenario is shown in Figure 3–10. The scenarios with substantial offshore wind generation (i.e. "Best Sites Offshore") - at both the 20% and 14% penetration levels exhibit the highest capacity factors of approximately 40% and 38%, respectively. The lowest capacity factors are associated with the "Best Sites by State" scenarios, where wind resource quality was de-emphasized in favor of a preferred geographic distribution of wind generation. Even so, the average capacity factors are still above 30%.

The aggregate capacity factors for the ISO-NE study scenarios are typical of the expectations for the wind resource in the northeastern U.S. The source data for NEWRAM covers the entire eastern U.S., and shows capacity factors of 40 to 50% for the best wind resources in the Great Plains. Capacity factors for sites in this database generally decline as one moves east.

The differences in annual capacity factors between years for all scenarios are relatively small, varying by less than 2% from the three-year average.

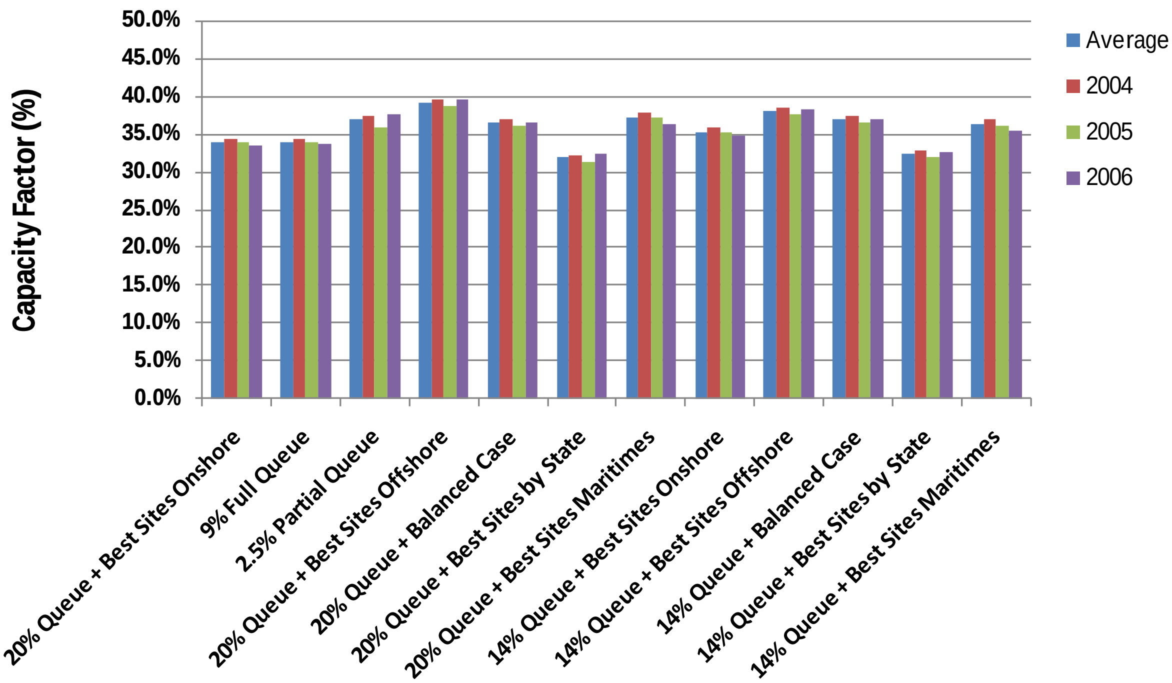


Figure 3–10 Average annual capacity factor for each scenario, and by year

Capacity factor by season averaged over all three years for each scenario are shown in Figure 3–11. High capacity factors in the winter season and low capacity factors in summer are the obvious features. Winter capacity factors ranged from 40% to 50% for all of the scenarios, with the scenarios containing significant offshore wind exhibiting the highest. Summer capacity factors fall below 30%, again, except for those scenarios with significant offshore resources.

Figure 3–11 also shows the capacity factor breakdown between on-peak and off-peak hours (peak load hours are defined for each season as Hour 11 through Hour 19). For all scenarios, in all seasons, the on-peak capacity factor exceeds that in the off-peak hours. This result is somewhat surprising relative to other integration studies and even the measured characteristics of many operating wind projects, where wind generation exhibits at least some negative correlation to average daily load patterns.

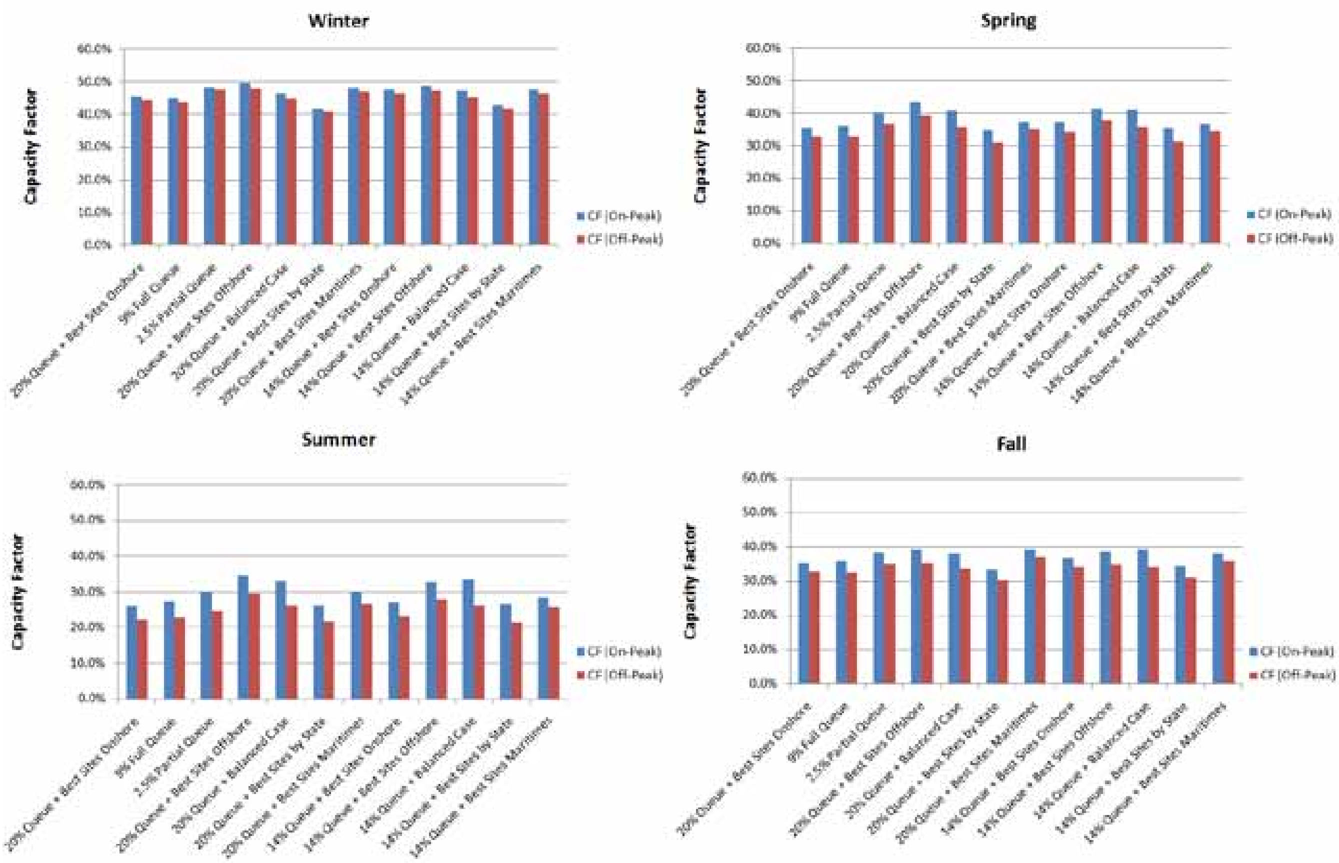


Figure 3–11 Capacity factor by (on-peak and off-peak) for each scenario (average of three years)

3.1.3 Hourly Variability – Diurnal Characteristics

The large-scale meteorological phenomena that drive wind generation exhibit cycles that are non-integer multiples of 24 hour days. In addition, other wind generation drivers, such as sea breezes or atmospheric mixing can correspond to diurnal cycles in certain seasons.

Averaging by hour of the day over an extended period such as a season can help reveal these patterns. Figure 3–12 through Figure 3–15 show the average daily patterns of wind generation for each scenario by season.

The winter pattern shown in Figure 3–12 is marked by two maxima in wind generation, one corresponding to the morning load pickup period, the other the late afternoon/early evening peak period. The pattern is evident in all scenarios. This would appear to be very desirable from a power system operations perspective. It should be remembered, however, that the patterns presented have been heavily smoothed by averaging over a large number of hours (over 1000), and the 3 year dataset available for analysis may not be indicative of behavior over longer record lengths, which could reveal larger meteorological patterns.

The average spring pattern (Figure 3–13) is less variable than that for winter, but also exhibits an increasing trend later in the day toward peak load hours. Production drops over the nighttime hours, and the timing of the increase over the day may or may not correspond to the morning load pickup.

The summer pattern in Figure 3–14 also shows declining levels of wind generation over the early morning until around or just after sunrise. Again, the timing of the pickup in wind generation in the average pattern would appear to be potentially helpful with morning load pickup, but the earlier qualifications also apply here.

The fall pattern (Figure 3–15) is similar to that in springtime, more constant than winter or summer, with a larger late-day peak.

Duration curves for each wind generation scenario using all three years of hourly data are shown in Figure 3–16.

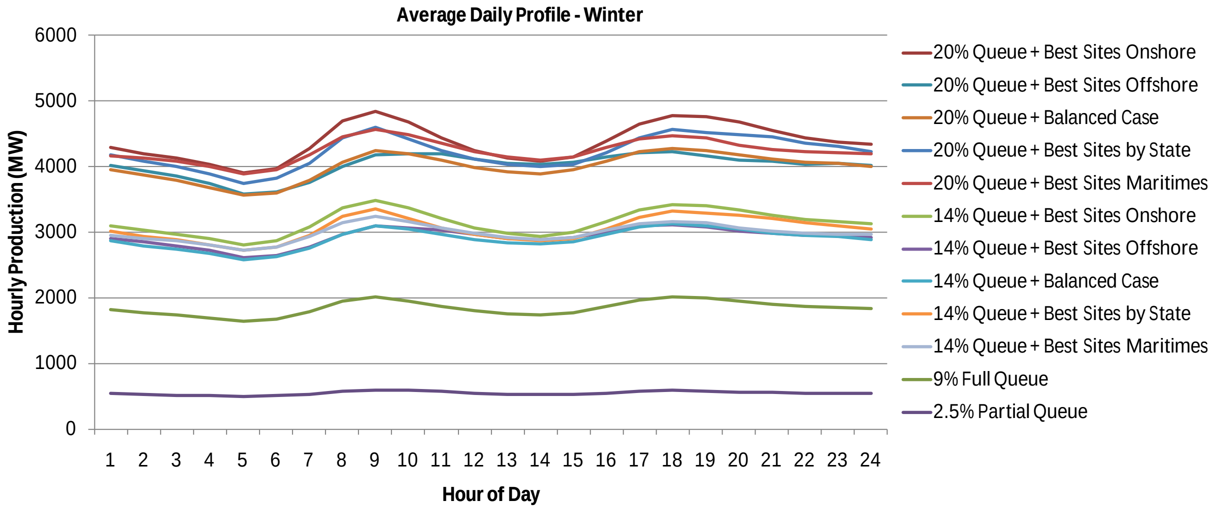


Figure 3–12 Average daily wind generation profile for winter (3 years of data)

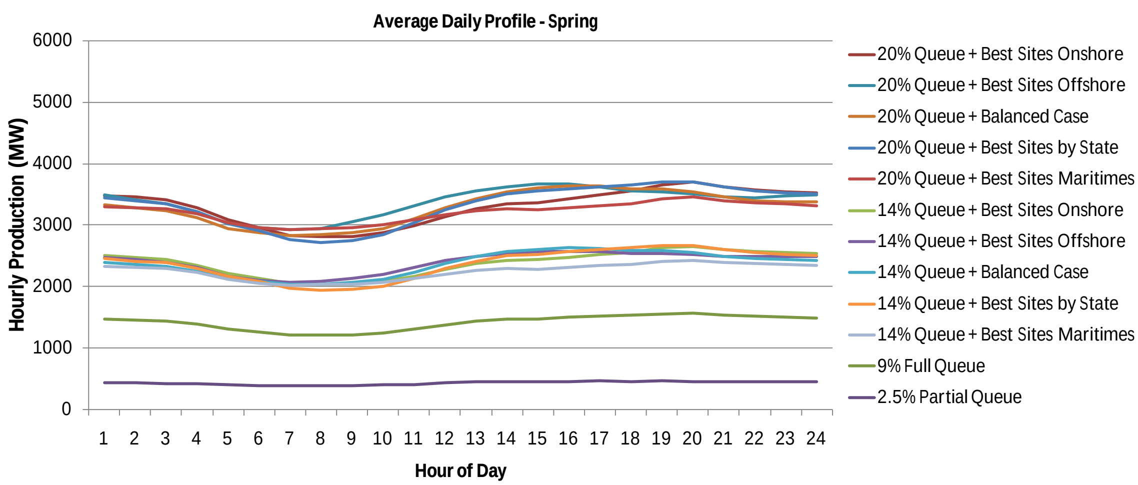


Figure 3–13 Average daily wind generation profile for spring (3 years of data)

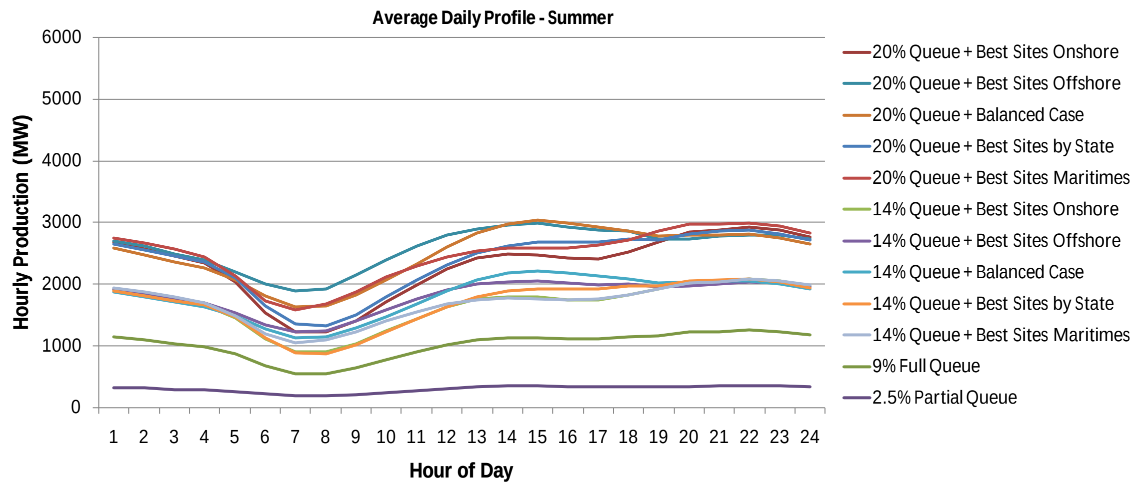


Figure 3–14 Average daily wind generation profile for summer (3 years of data)

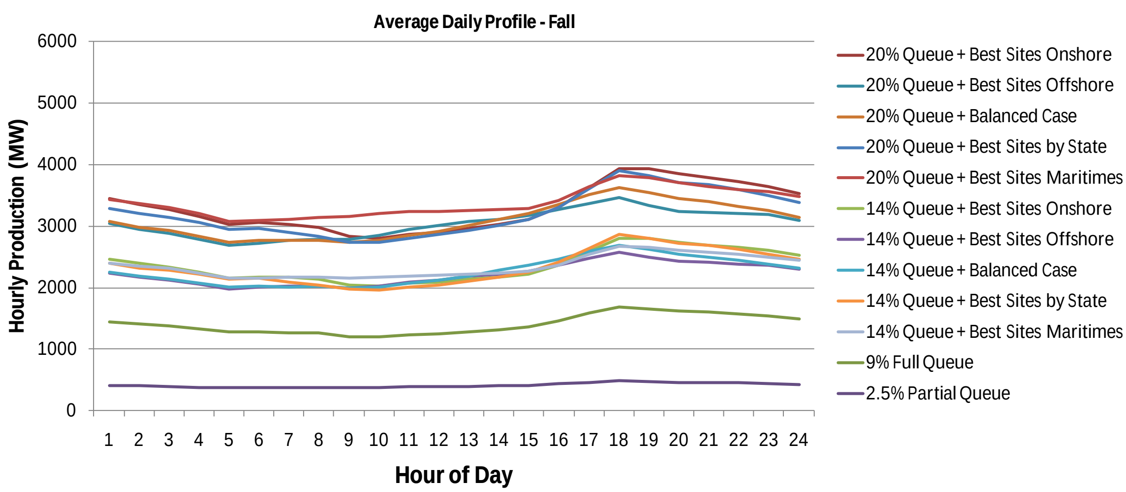


Figure 3–15 Average daily wind generation profile for fall (3 years of data)

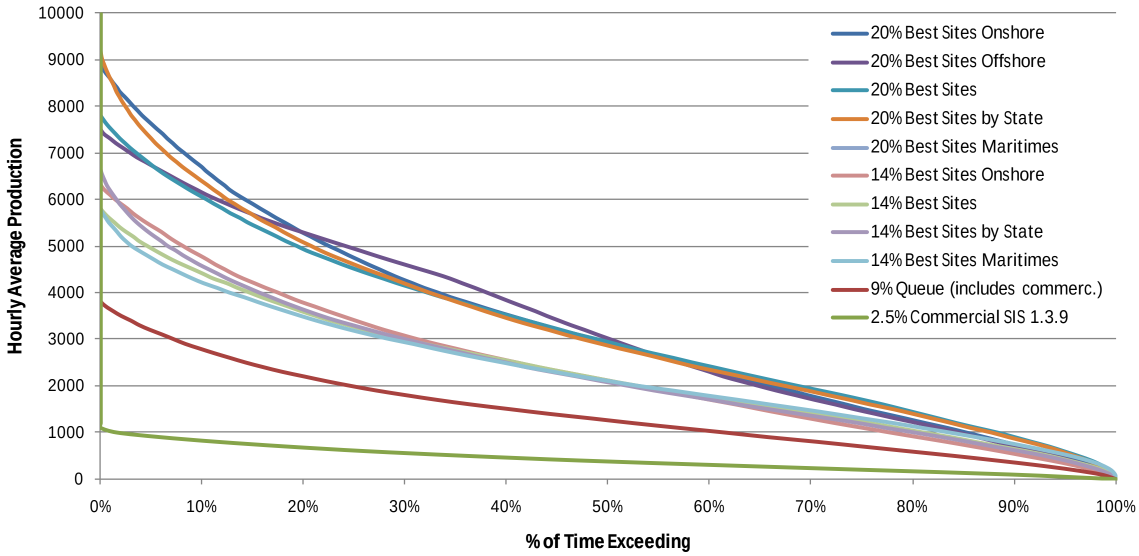


Figure 3–16 Hourly duration curves for each wind generation scenario

Increasing granularity helps to reveal more details about the behavior of the aggregate wind production in each scenario. Figure 3–17 through Figure 3–21 below show the hourly average daily production by month for each scenario, along with the maximum and minimum values for each hour. The data is based on all three years of data in the NEWRAM, or over 26,000 chronological hours of data.

The trends noted previously are again evident here, with highest production during the winter and lowest in summer. The charts also show a diurnal pattern in the summer, but not in winter. During the spring and fall seasons, the pattern appears transitional, with more diurnal behavior in the months nearer to summer, and less in those adjacent to the winter season.

For all scenarios, periods of zero or very low production occur in all months of the year. Hours of maximum production, near the installed nameplate capacity of the wind generation in each scenario, occur in all seasons except summer.

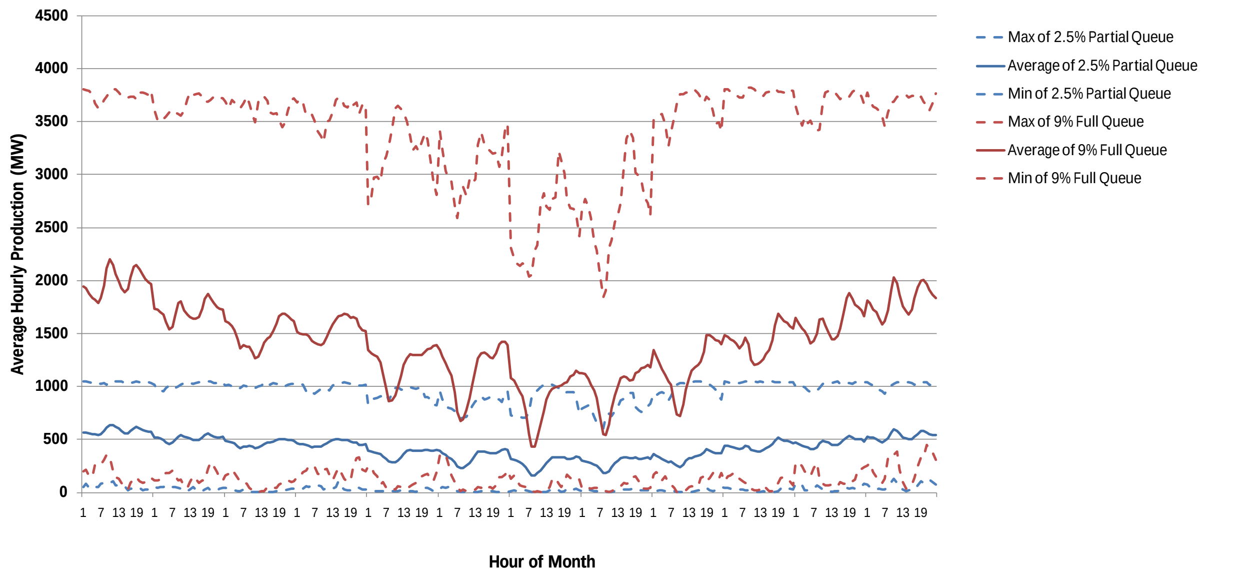


Figure 3–17 Average daily patterns by month for low penetration scenarios; maximum and minimum values indicated by dashed lines.

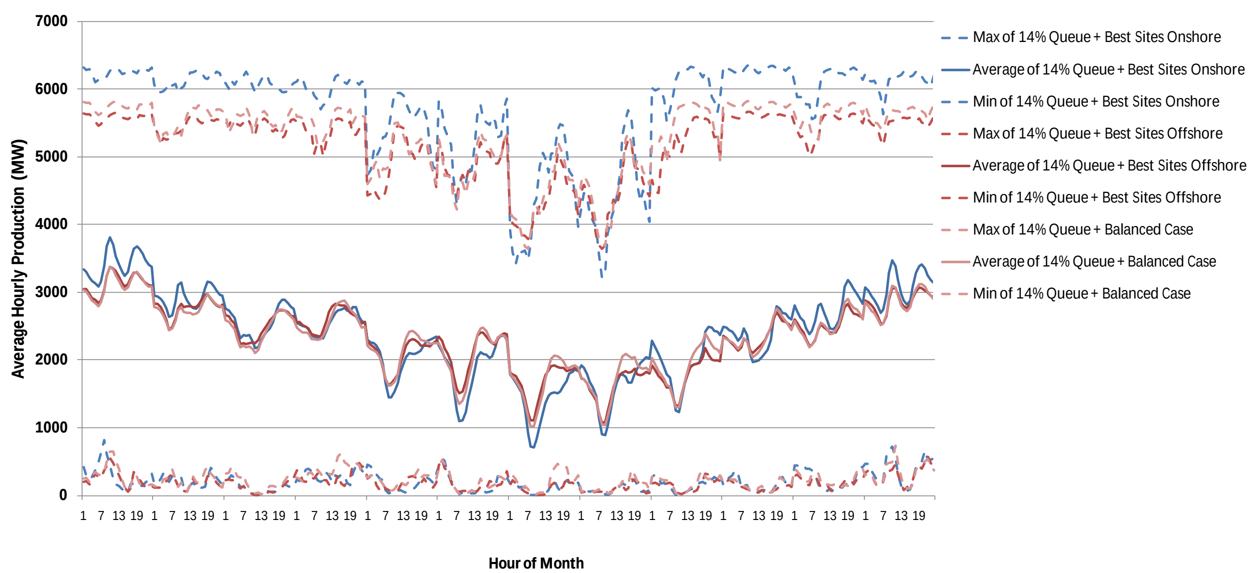


Figure 3–18 Average daily patterns by month for three 14% scenarios; maximum and minimum values indicated by dashed lines.

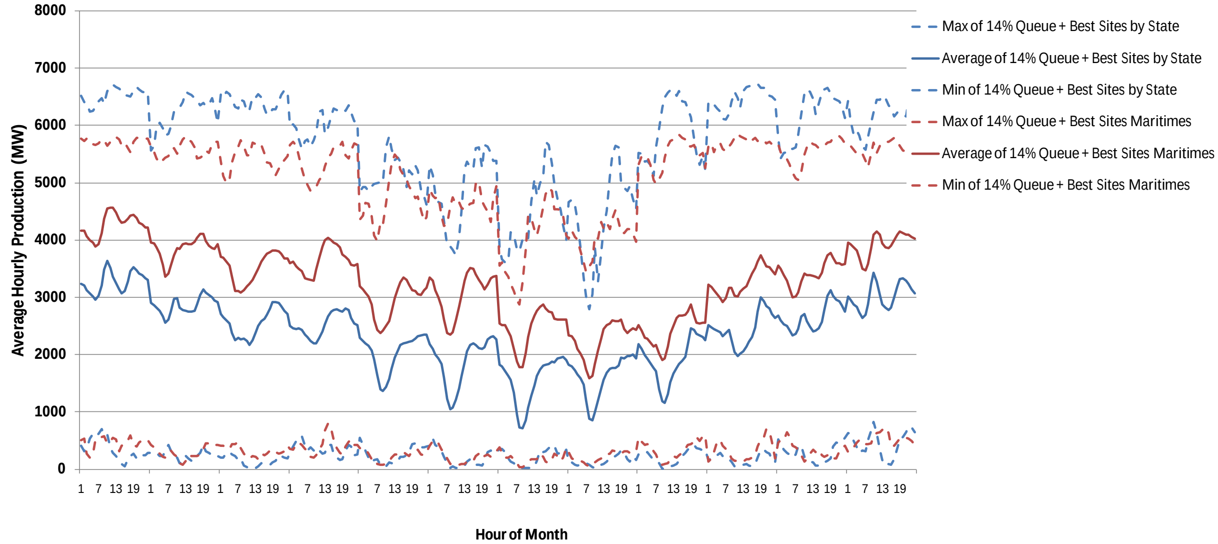


Figure 3–19 Average daily patterns by month for two 14% scenarios; maximum and minimum values indicated by dashed lines.

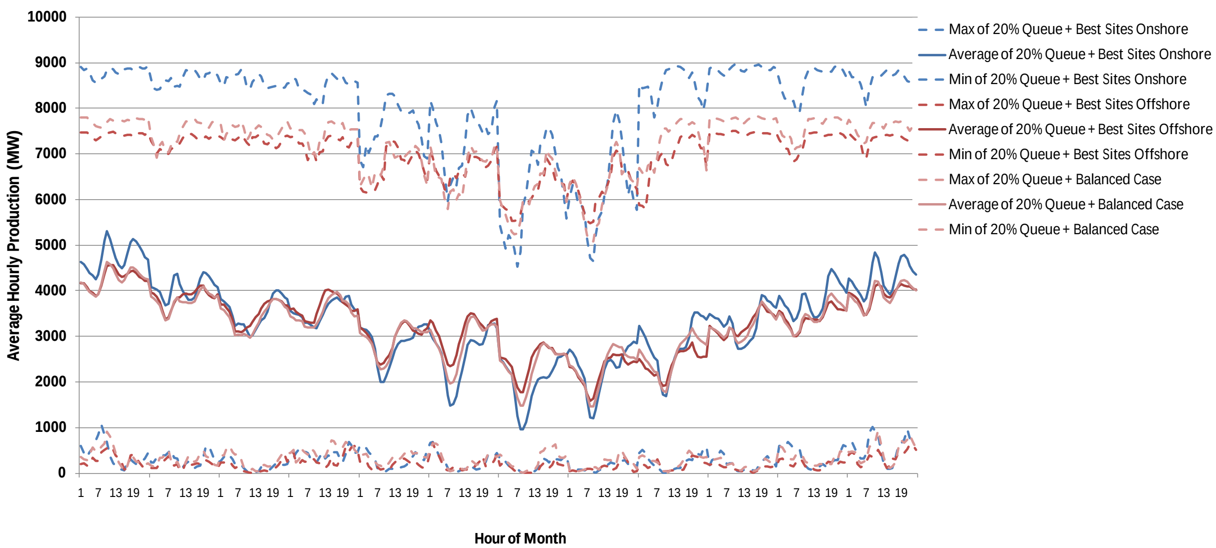


Figure 3–20 Average daily patterns by month for three 20% scenarios; maximum and minimum values indicated by dashed lines.

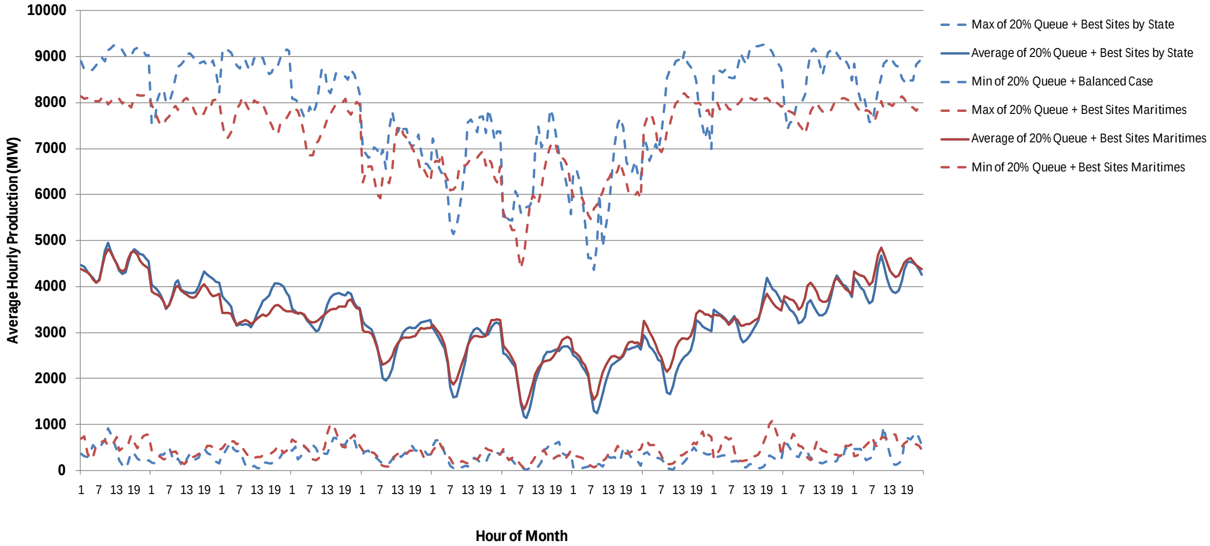


Figure 3–21 Average daily patterns by month for two 20% scenarios; maximum and minimum values indicated by dashed lines.

3.1.4 Daily Variability – Load net of Wind Generation

The average daily patterns of wind generation for each season are interesting and can, to the knowledgeable eye, help reveal some of the driving forces behind regional wind generation. Operationally, though, how wind generation patterns combine with those of load is of much more interest. Figure 3–22 though Figure 3–25 combine the daily wind generation patterns above with average ISO-NE 2020 load for each hour and season. Load and net load duration curves for the three years of data are found in Figure 3–26.

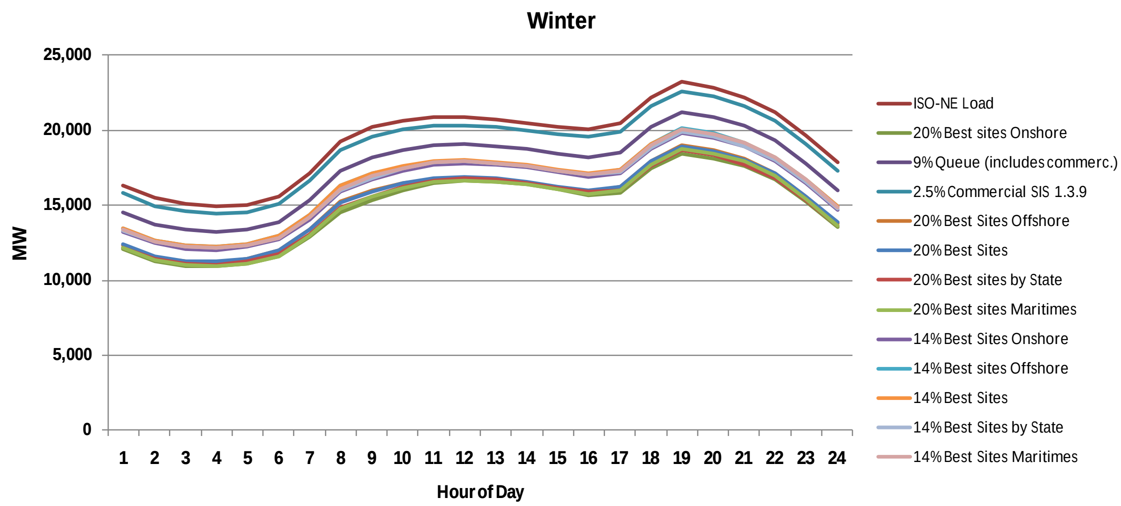


Figure 3–22 Average daily net load profiles for each scenario, winter season

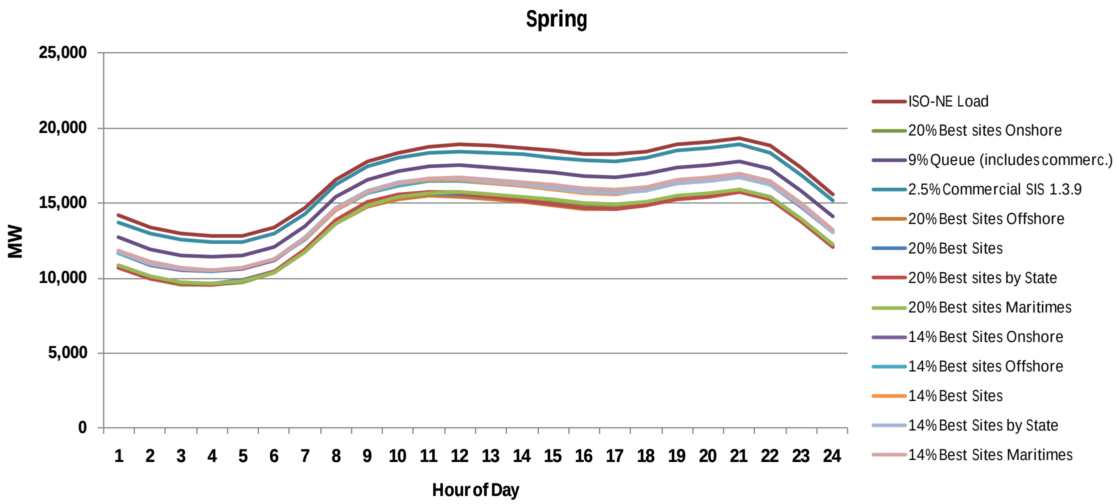


Figure 3–23 Average daily net load profiles for each scenario, spring season

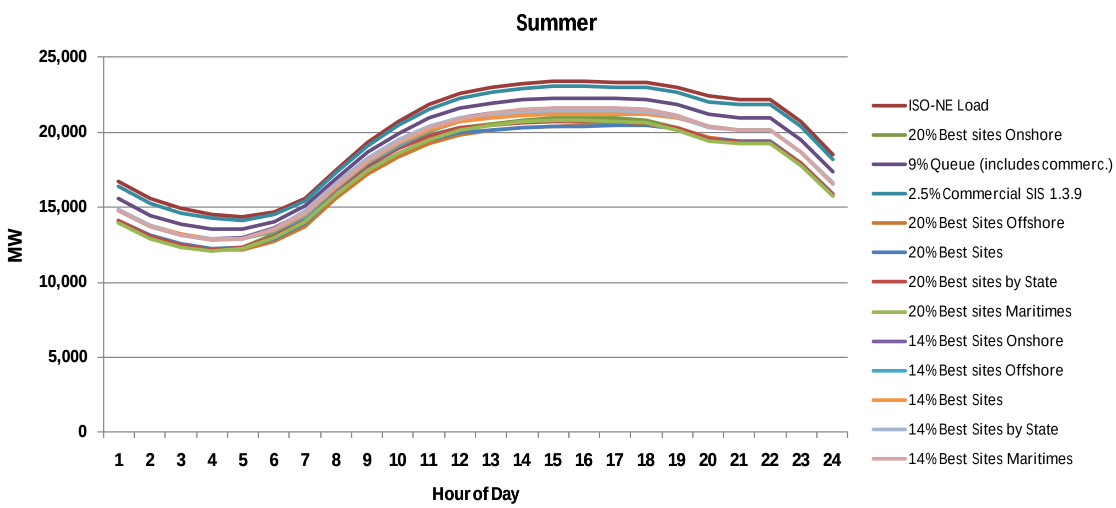


Figure 3–24 Average daily net load profiles for each scenario, summer season

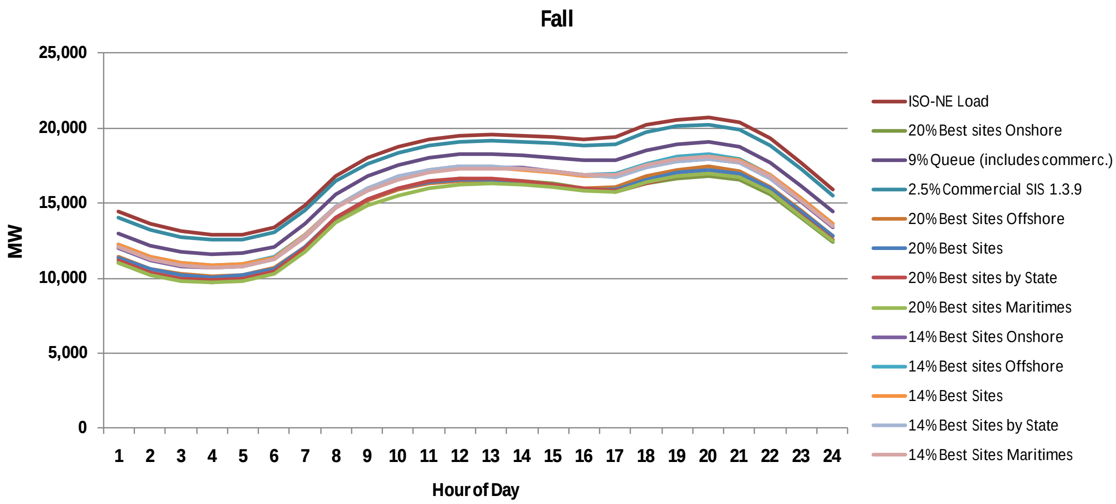


Figure 3–25 Average daily net load profiles for each scenario, fall season

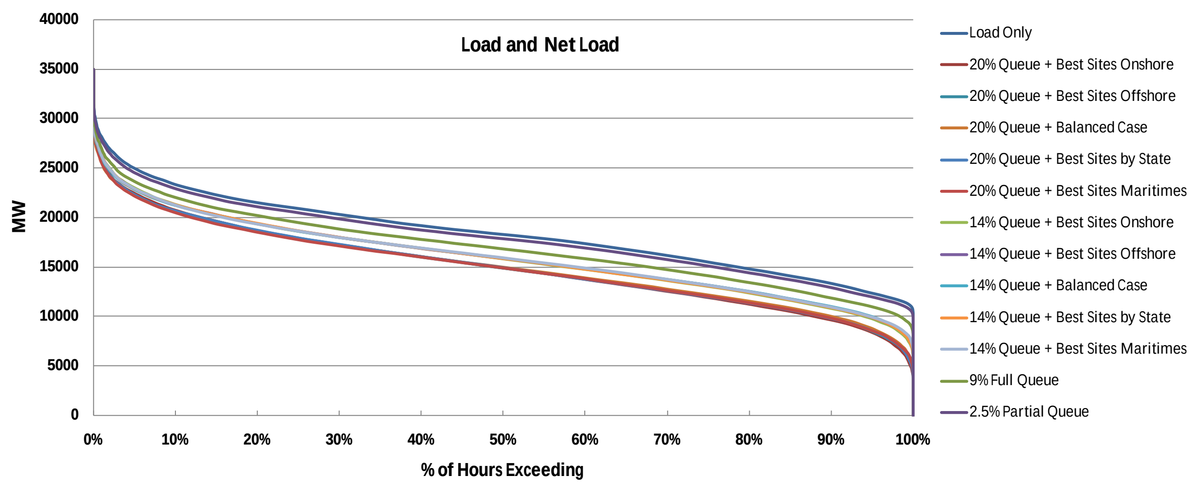


Figure 3–26 Duration curves for load and load net wind, all scenarios, all years, all hours

The substantial smoothing resulting from averaging over a large number of hours disguises many of the important operational challenges that may be imposed by wind generation. Other views of the data can reveal more regarding impacts of wind variability on the net load. Figure 3–27 shows the hourly changes in ISO-NE load for all three years of data. Hourly changes in wind generation are shown for all scenarios in Figure 3–28 through Figure 3–30. It is apparent from the respective distributions that the lower penetration scenarios would not have much effect on the aggregate changes when combined with load, with increasing influence as the penetration grows. Again, the specific impacts must be evaluated through chronological production simulations, as the ability of the ISO-NE fleet to respond to changes in demand will depend on factors beyond wind and load.

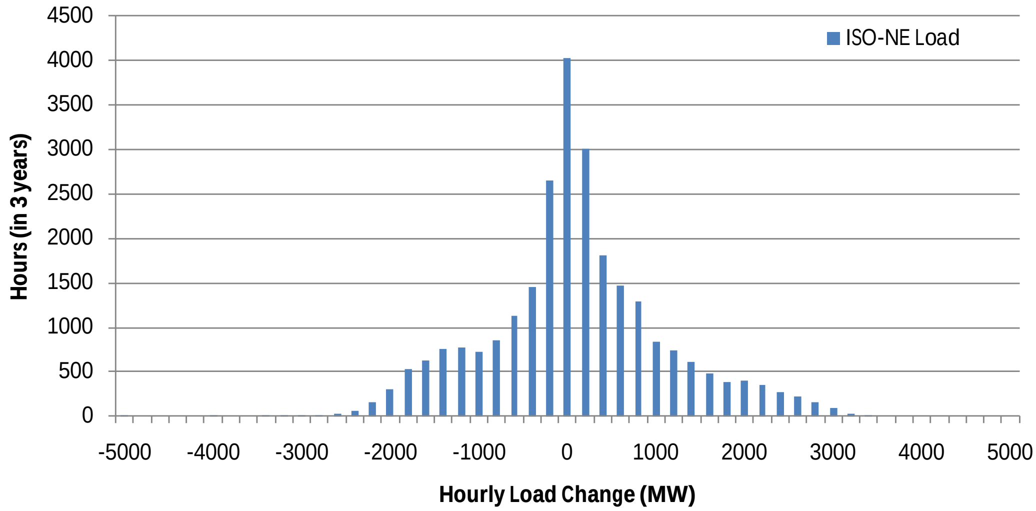


Figure 3–27 Distribution of all hourly ISO-NE load changes (3 years of data)

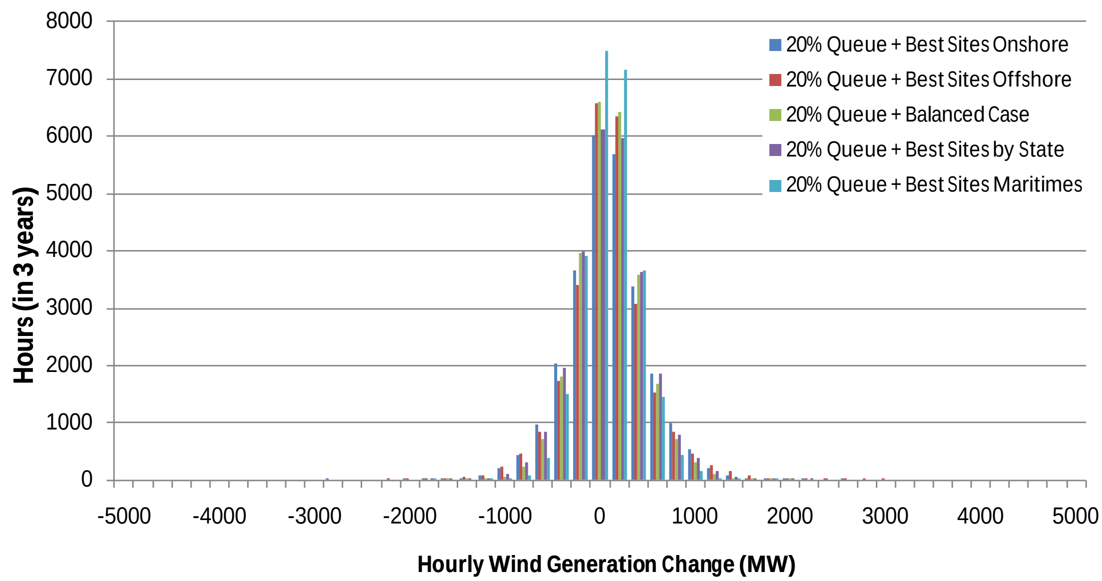


Figure 3–28 Hourly changes in wind generation for 20% penetration scenarios

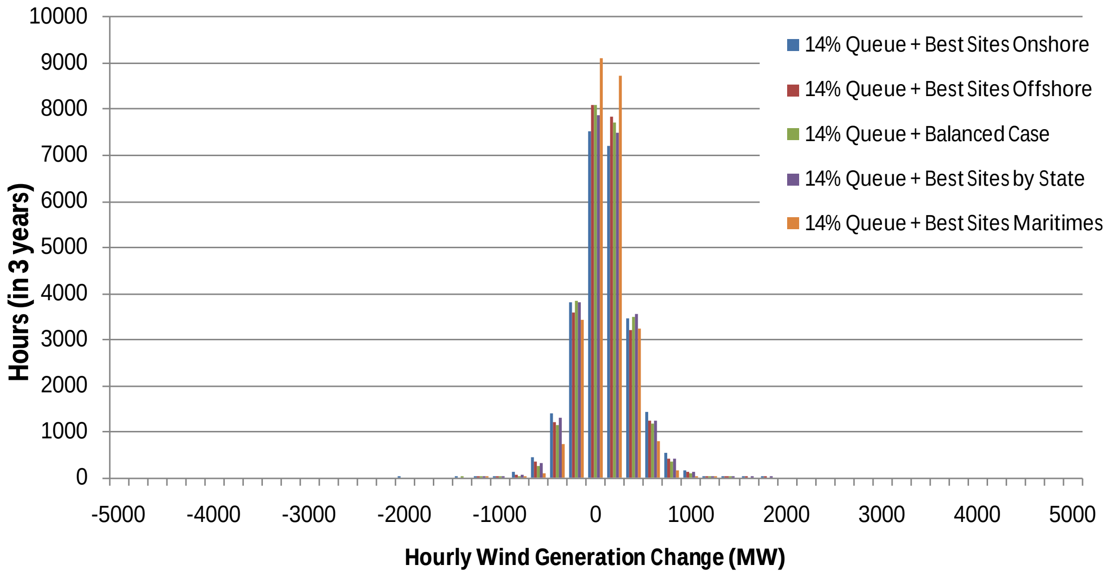


Figure 3–29 Hourly changes in wind generation for 14% wind penetration scenarios

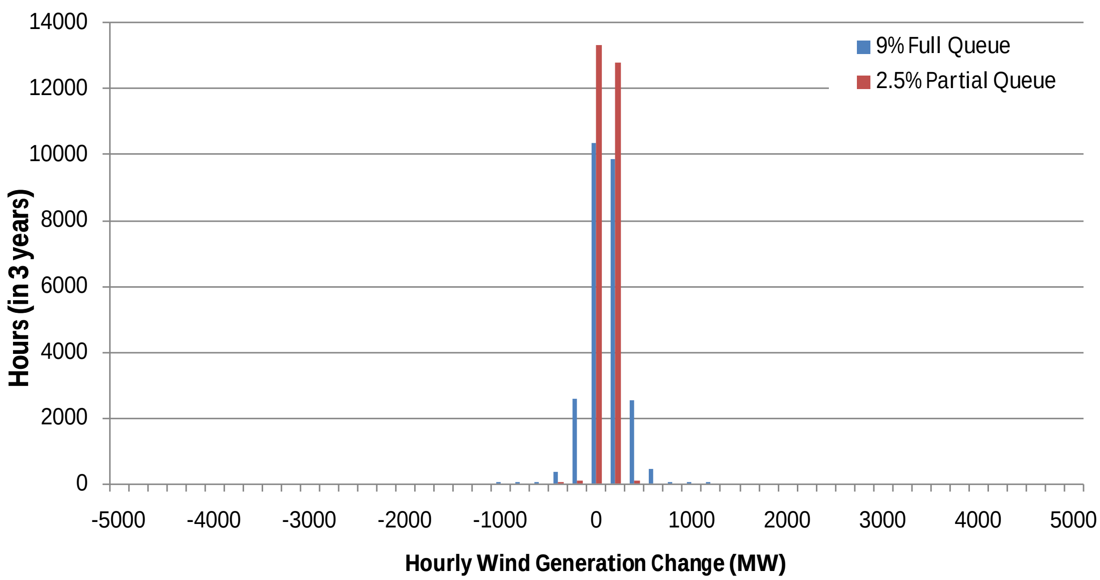


Figure 3–30 Hourly changes in wind generation for lower penetration wind scenarios

Some general operational impacts are better viewed as a comparison of the distribution of hourly changes in ISO-NE load only to those of the net load in the scenarios. These comparisons are depicted in Figure 3–31 through Figure 3–34 for 2.5%, 9%, 14%, and 20% penetration scenario, respectively.

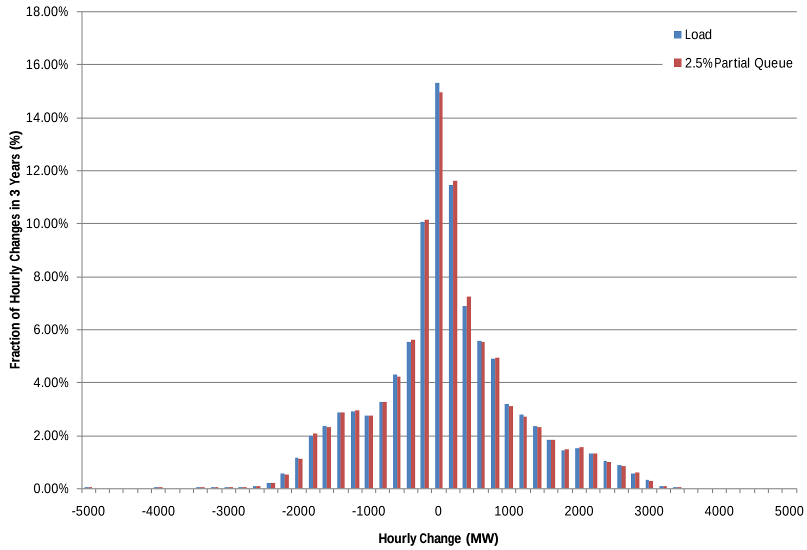


Figure 3–31 Hourly change in ISO-NE load and net load for 2% Partial Queue (3 years of data)

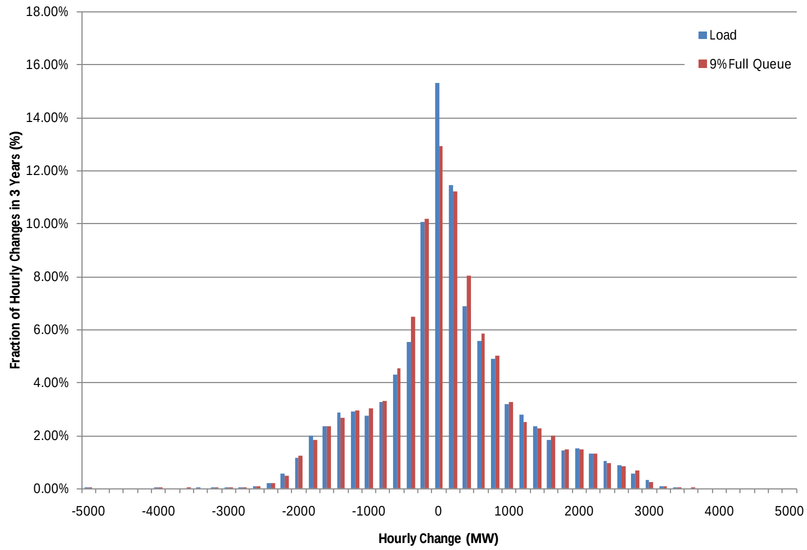


Figure 3–32 Hourly change in ISO-NE load and net load for 9% Full Queue (3 years of data)

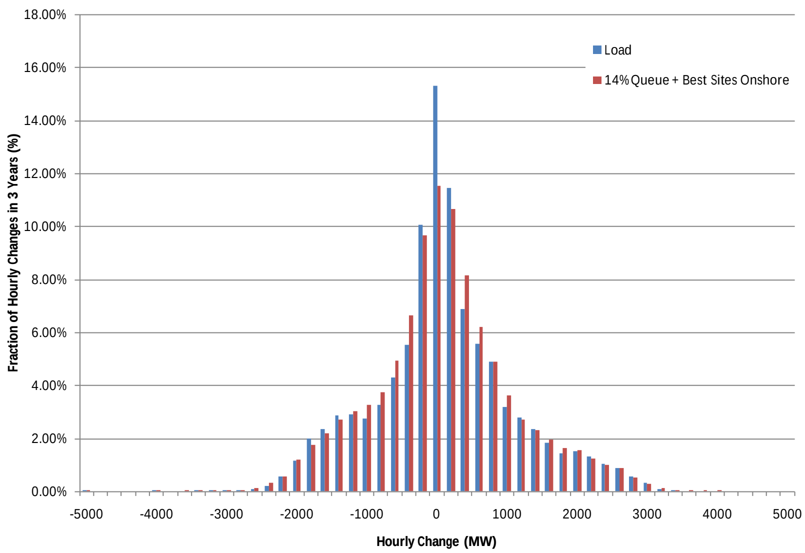


Figure 3–33 Hourly change in ISO-NE load and net load for 14% Queue + Best Sites Onshore scenario (3 years of data)

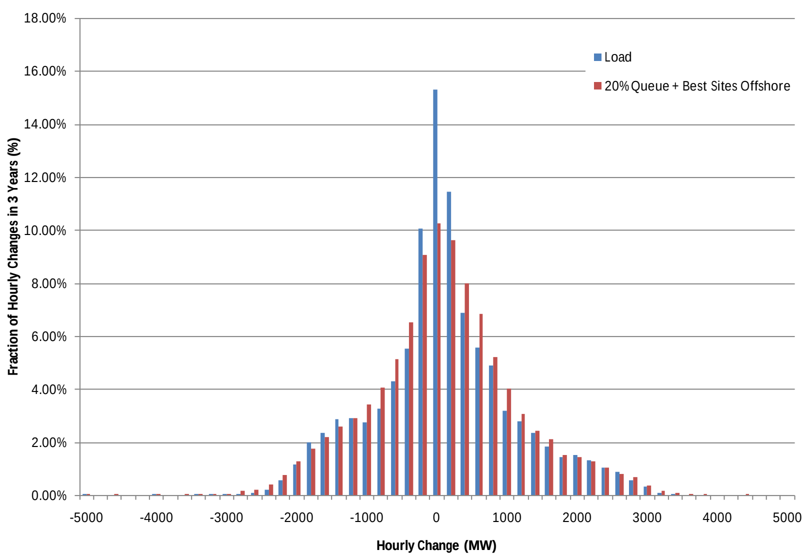


Figure 3–34 Hourly change in ISO-NE load and net load for 20% Queue + Best Sites Onshore scenario (3 years of data)

Even for the 20% scenario, the difference between the load only and net load case is relatively subtle. Expanding the view on the tails of the distribution for the 20% Queue + Best Sites Onshore case (Figure 3–35) helps to reveal the impact of wind generation.

It can be seen from the figure that the number of extreme hourly changes is increased with wind generation. Each 0.10% increment on the vertical axis corresponds to about 26 events over the 3 year data record. The right half of the picture shows that there are several (about 10 for this particular scenario) hourly increases in net load for this scenario that are greater than those observed for load alone.

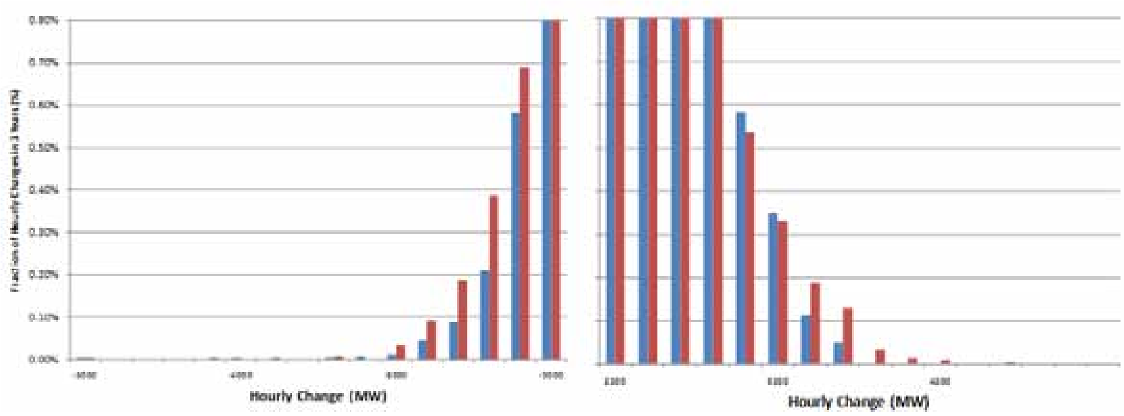


Figure 3–35 Tails of the distribution of hourly changes for ISO-NE load and net load for 20% Queue + Best Sites Onshore scenario

Any increase in the number or magnitude of extreme hourly changes is important operationally. Views through comparison of hourly load and net load data can confirm their size and existence, but say little about specific impacts on the ISO-NE system. The hourly production simulations described in a later section are where the real operational impacts are assessed and quantified. The extreme events that can be identified in the statistical and quantitative characterizations are evaluated in the appropriate context of the entire power system, its individual elements, and the full range of operating constraints.

3.1.5 Faster Variations in Wind Generation

The discussion thus far has focused on variations in wind generation, ISO-NE load, and load net of wind generation on an hourly basis. Chronological production simulation at one-hour time steps is the primary analytical machinery for this wind integration study; via these simulations, each actual day which contributes a small amount to the hourly averages above will be examined in detail. Consequently, the preceding discussion is intended to provide an overview of the major impacts of wind generation on the net demand against which ISO-NE generating resources will be committed and dispatched. The chronological production simulations will provide the quantitative detail regarding wind generation impacts on ISO-NE operations.

Variations of load and wind generation on smaller time scales are also important operationally. Because these cannot be directly evaluated through hourly production simulations, characterizations of the faster variations in load and wind will be used later to ascertain additional operation impacts such as incremental regulation needs and operating reserve impacts.

The data used for this analysis consists of ten-minute resolution wind data from the wind data set. A first measure of the variability within the hour can be made by simply looking at the magnitude change from one interval to the next.

Figure 3–36, Figure 3–37, and Figure 3–38 contain pictures of the wind generation variability from one ten minute interval to the next for each scenario. Changes in production to the next interval are plotted on the vertical axis against the current production level on the horizontal. The spread from top to bottom across each “cloud” s a measure of the within-hour volatility, and illustrates directly how wind generation can increase the range of maneuverable generation necessary to balance supply and load.

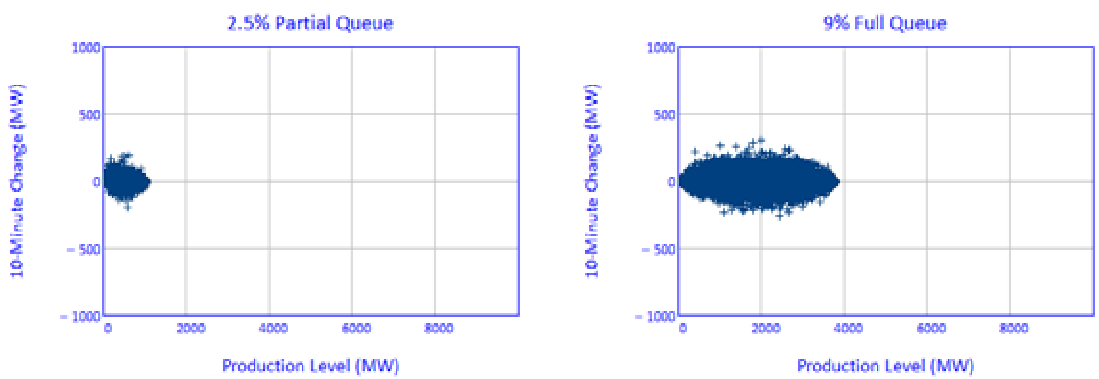


Figure 3–36 “Cloud” charts showing ten-minute variability as a function or wind production level 2.5% and 9% scenarios

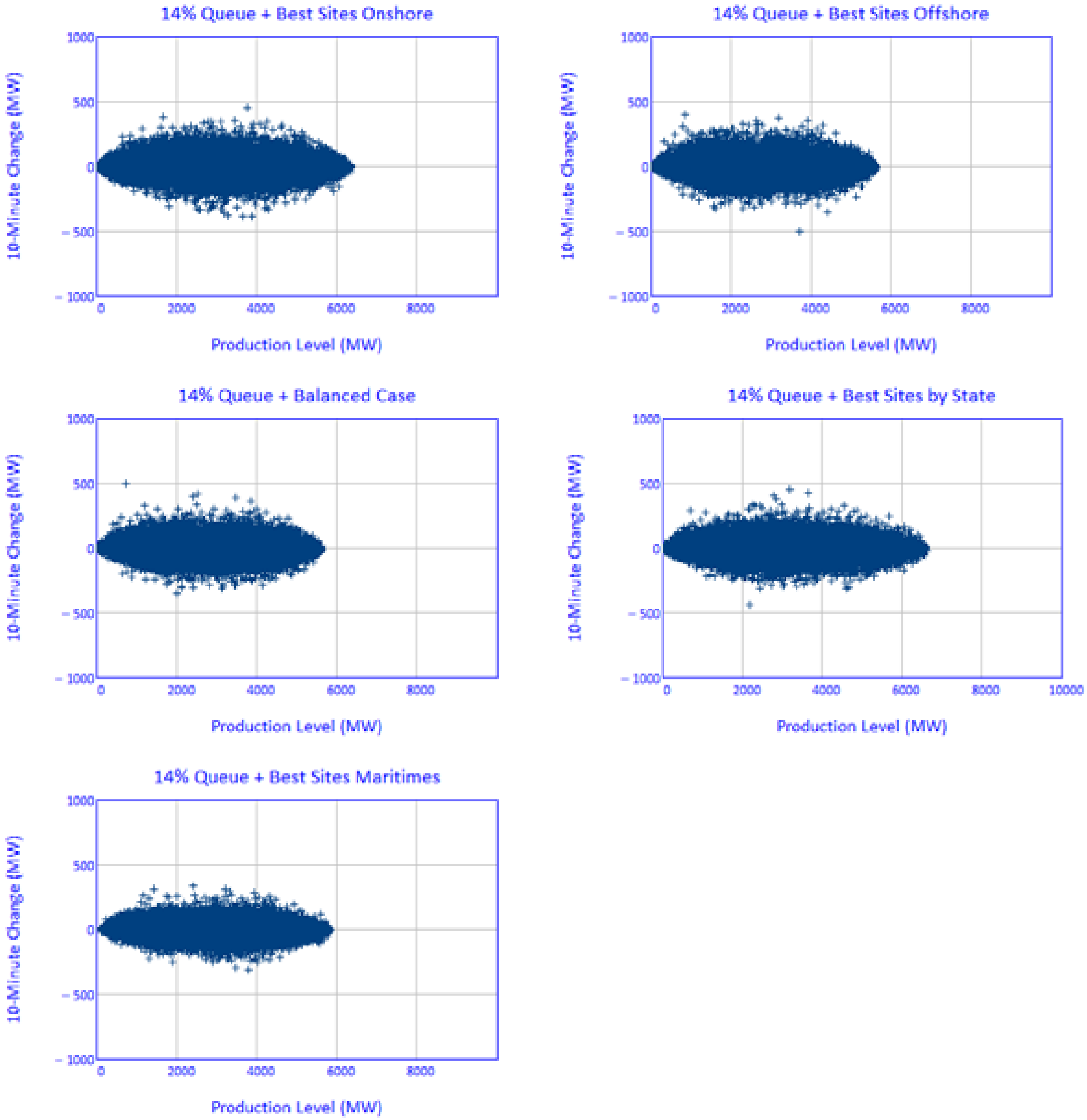


Figure 3–37 Ten-minute variability as function of production level for 14% scenarios

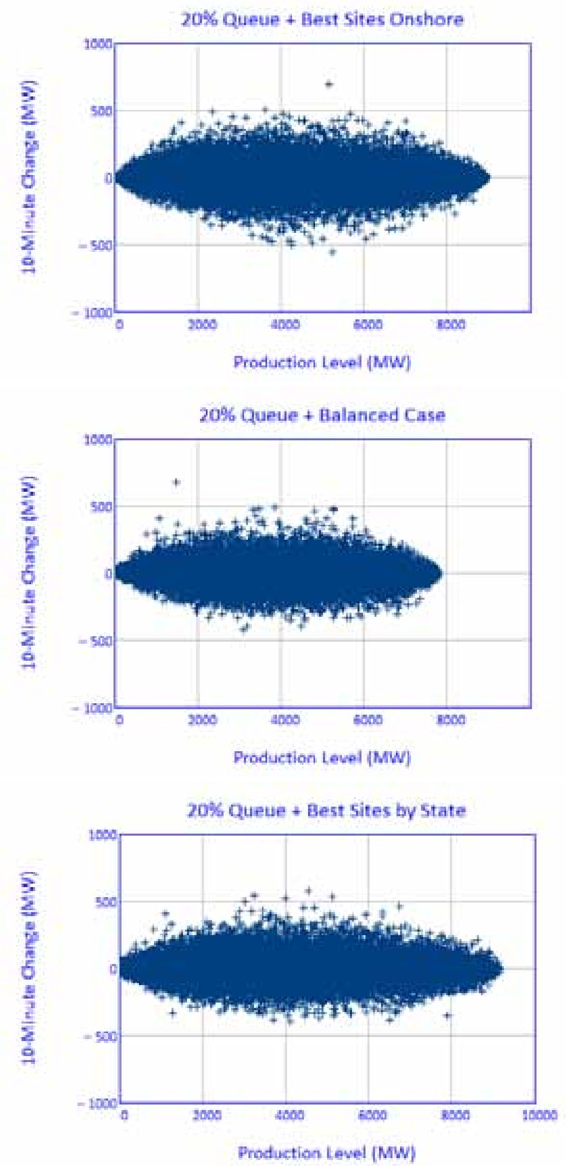


Figure 3–38 Ten-minute variability as function of production level for 20% scenarios

Statistics of the ten-minute variability of aggregate wind generation provides a useful characterization that will be used later in quantitative analysis of regulation needs and operating reserve impacts. Figure 3–39 is a modification of the cloud charts above. Ten-minute variations (changes from one data point to the next in the ten-minute dataset) are grouped by the average hourly production level during the time the variation occurred. Hourly production levels are then organized into “bins,” where the 10% to 20% bin, for example, contains all of the ten-minute variations that occurred when the hourly production was between 10 and 20% of aggregate nameplate capacity.

Once sorted, the standard deviation of the variations in each bin is computed, and plotted against production level, as shown by the red squares in Figure 3–39. Three years of ten-minute data result in over 150,000 samples. Because of the large sample size, the distributions in each bin are quite Gaussian, so the standard deviation becomes a useful metric for calculating the expected magnitude of variations.

The shape of the curve in Figure 3–39 bears some explanation. At low levels of wind generation, the expected variations are small mainly due to low wind speed levels. The expected variations are highest near 50% of nameplate production because wind speeds are such that each turbine is operating on the steepest portion of the power curve (power is a function of the wind speed cubed). As the aggregate production level increases further, winds are more vigorous and there is a larger probability that at least some of the individual turbines in the aggregate are operating above rated wind speed. In this region, variations in wind speed have little to no impact on production, i.e. the power output of the turbine remains constant as wind speed varies. Consequently, the expected variation from one interval to the next is much smaller than at lower production levels.

It must be kept in mind that these statistical characterizations of variability are applied to all of the wind turbines in the scenario as a whole. They are useful here because of the large amounts of wind generation assumed for each scenario. In practice, a similar approach might be used. Wind plant production data from EMS archives – which would be of much higher resolution (e.g. SCADA scan periodicity, about 4 seconds) that what is available for this study – can be periodically extracted and analyzed in a manner similar to what is shown here. The result would be statistical characterizations of the actual wind generation fleet that could be fed into analyses of regulation and operating reserve needs going forward.

Figure 3–39 through Figure 3–42 show characterizations of ten-minute variations for four wind generation scenarios, using three years of data. The blue lines on each chart are approximations of the empirical data represented by the red squares. The shape suggested by the empirical data provides for a simple curve fit using a quadratic expression.

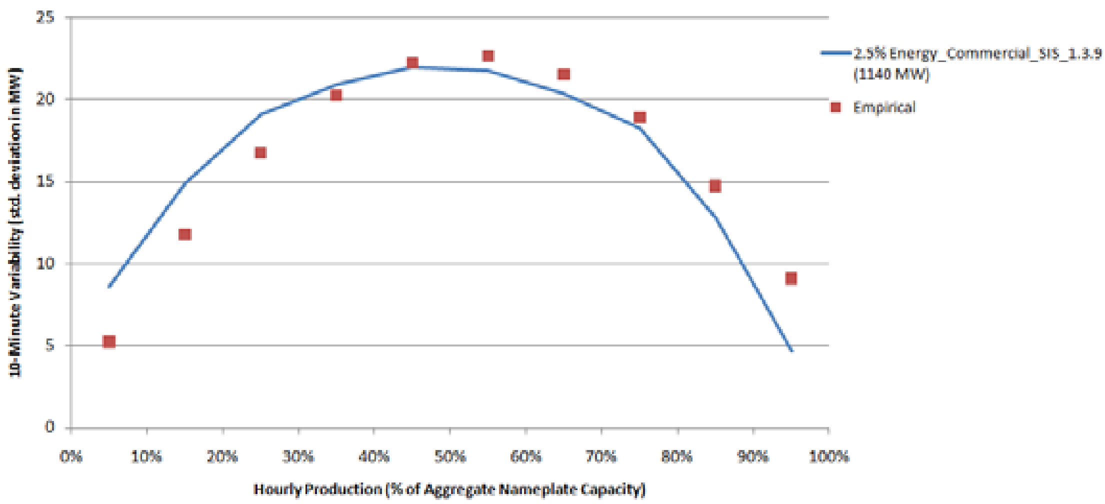


Figure 3–39 Statistical characterization of ten-minute variability for 2.5% scenario

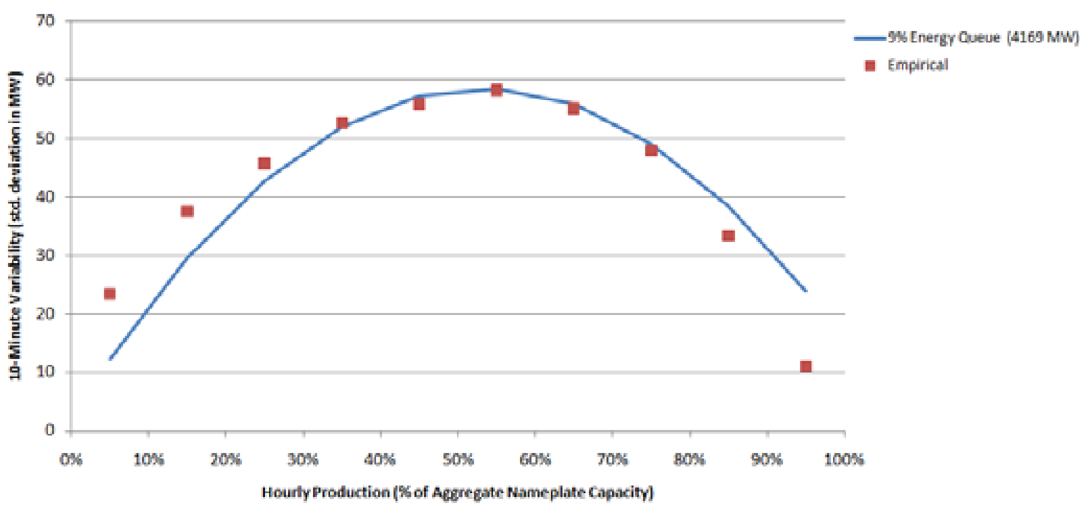


Figure 3–40 Statistical characterization of ten-minute variability for 9% scenario

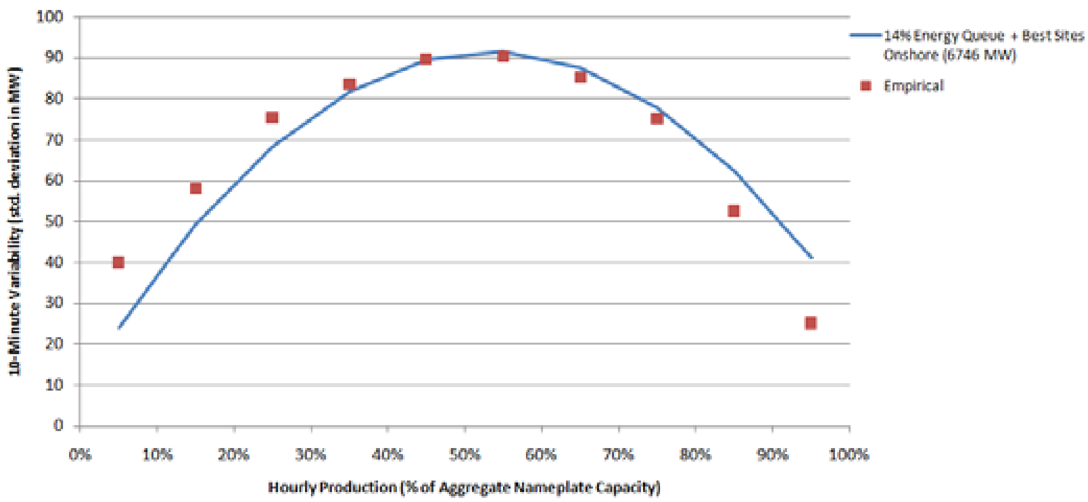


Figure 3–41 Statistical characterization of ten-minute variability for 14% scenario

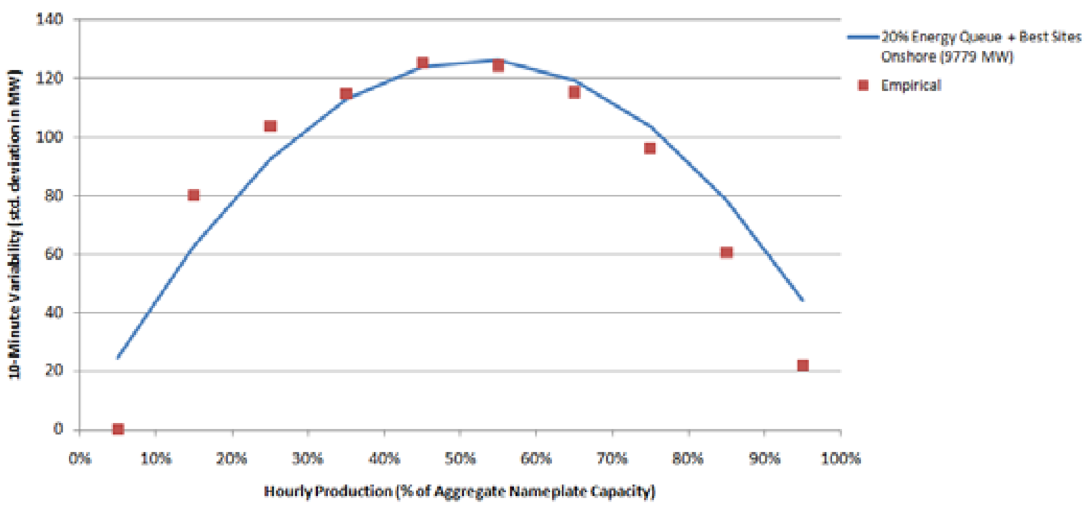


Figure 3–42 Statistical characterization of ten-minute variability for 20% scenario

Characterizations of ten-minute variability for all twelve wind generation scenarios are shown in Figure 3–43 through Figure 3–45. All curves are plotted on the same vertical scale to emphasize relative variability. As the installed capacity is increased, so does the expected variability. There are some subtle differences, however. Processing the ten-minute variability in this way actually captures some unique aspects of each scenario. For example, in Figure 3–45, substantial differences in the maximum expected variability between scenarios can be seen. While not proven rigorously, the likely explanation is that geographic diversity of the scenarios varies significantly. The “Best Sites by State” and “Best Sites + Maritimes” spread the total wind generation over the largest area. The “Best Sites Onshore” and “Best Sites Offshore” use the highest quality wind resources, thereby confining wind generation to a much smaller geographic area.

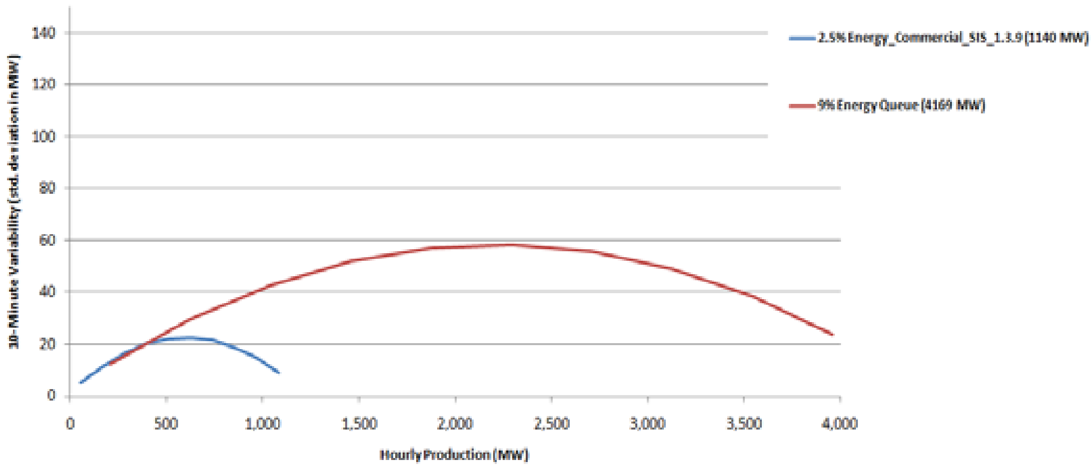


Figure 3–43 Characterization of ten-minute variability for lower penetration wind scenarios

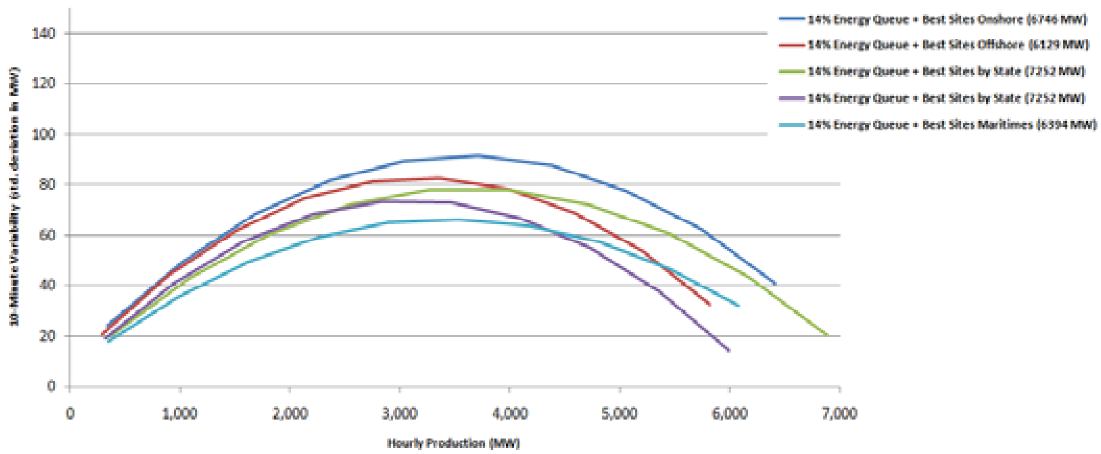


Figure 3–44 Characterization of ten-minute variability for 14% penetration wind scenarios

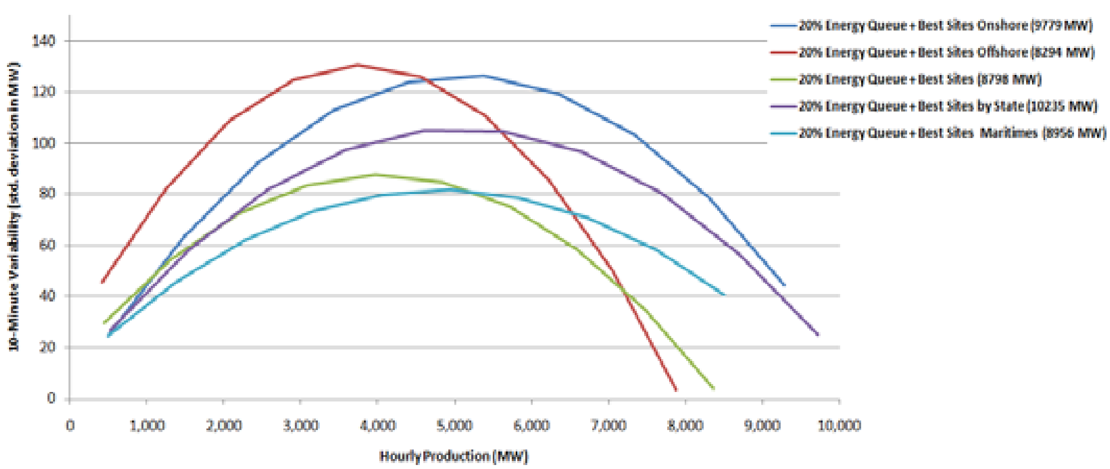


Figure 3–45 Characterization of ten-minute variability for 20% penetration wind scenarios

3.2 Wind Generation Forecasting and Uncertainty

The accuracy with which wind generation can be predicted varies with the forecast horizon. Beyond a week or so, it is nearly impossible to predict hourly production with any reasonable accuracy; forecasts based on empirical or historical data, as presented here previously, would likely be as accurate as much more sophisticated methods. Fortunately, forecast accuracy for both load and wind generation will increase as the horizon is shortened.

In power system operations, the critical horizons are those used by operators to commit, schedule, and dispatch generation. The day-ahead forecast, meaning a forecast of hourly production over the 24 hours of the next day and generated about twelve hours prior to the start of the target day, is a critical input to processes that optimize the economic efficiency of the system within security and reliability constraints. Errors in the forecast quantities – load and wind generation - that drive the commitment and dispatch processes can have consequences for the economic efficiency and/or reliability of the system. Over-forecasting of wind generation can result in commitment of too much conventional generation leading to excess uplift charges; under-forecasting may lead to depletion of reserves and very high locational marginal prices (LMPs).

Even shorter horizons are also important, as “looking ahead” is a fundamental part of power system operation. These horizons range from an hour to four or more hours into the future.

The NEWRAM dataset developed for this study also includes forecasts of production for each hour that represents a prediction made during the previous day, four hours prior to the start of the hour, and one hour prior.

The objective here is to characterize wind generation forecast accuracy for the horizons integral to the study:

- The day-ahead forecast used in unit commitment,
- An hour-ahead forecast that factors into operating reserve considerations, and
- A very short-term forecast (10-minutes ahead) that is used to assess incremental regulation needs, as will be described in Chapter 4.

3.2.2 Day-Ahead

Mean-Absolute-Error is the chosen metric for forecast accuracy. It is calculated by dividing the difference between the actual and forecast value each hour by the aggregate nameplate capacity, taking the absolute value, summing over all the hours, then dividing by the number of hours.

The day-ahead forecast accuracy over all three years of the NEWRAM dataset for each scenario is shown in Figure 3–46. The values are consistent with the current state-of-the-commercial art forecasts having MAEs in the 15 and 20% range.

Forecast accuracy varies seasonally as shown in Figure 3–47. Errors are lowest in summer, when wind production is lowest; the improved accuracy might be attributable to the differing weather patterns that drive wind generation in this season in that they are somewhat easier to forecast [see Task 2 report].

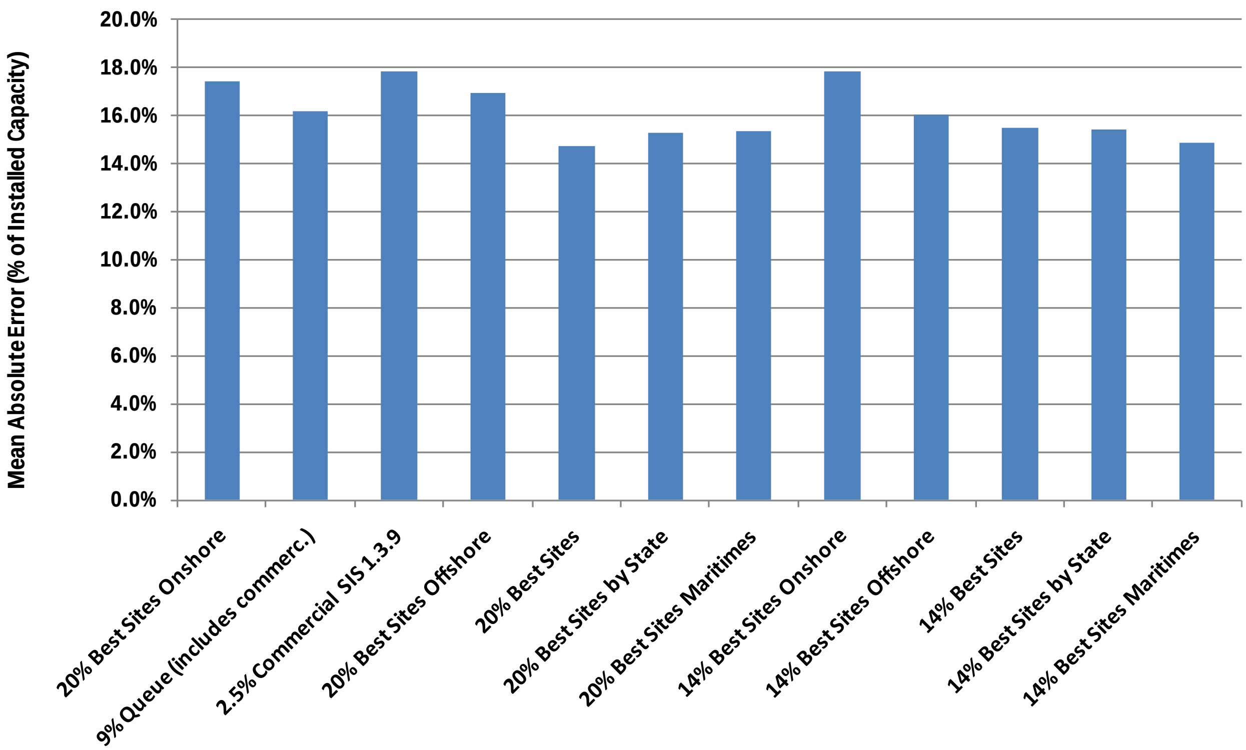


Figure 3–46 Mean-Absolute-Error for day-ahead forecast, all scenarios, all hours

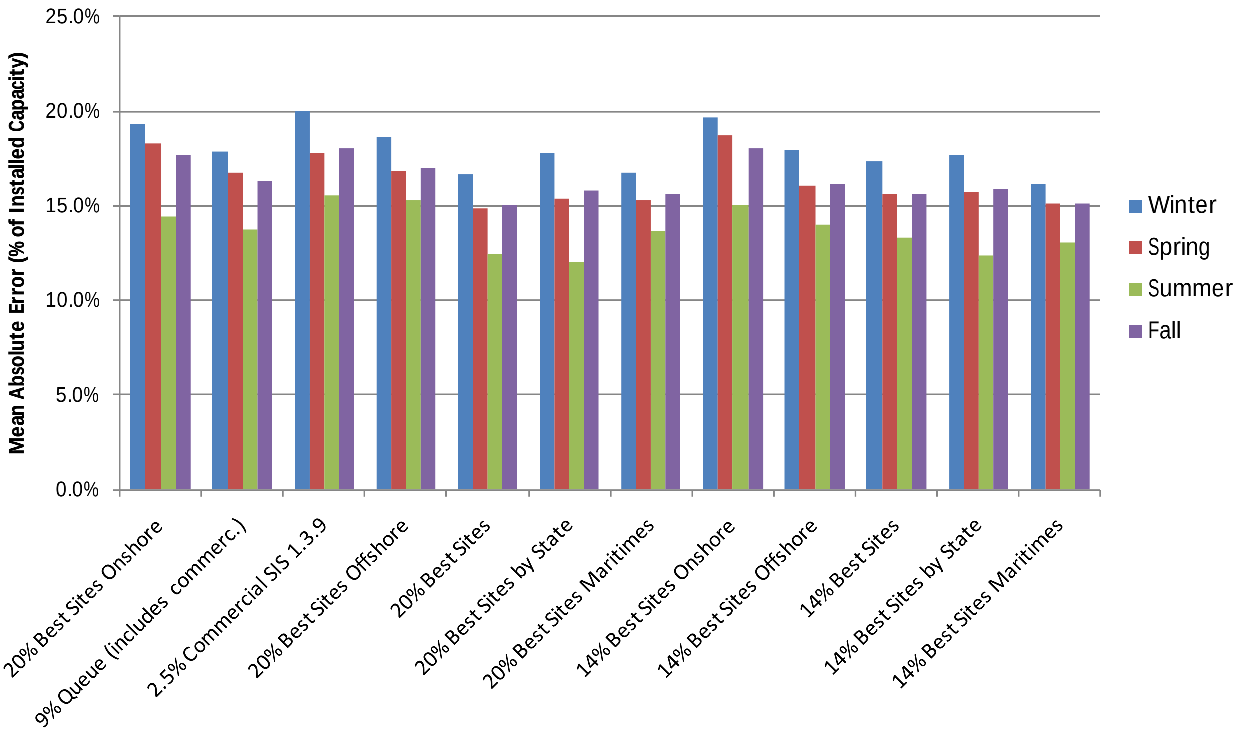


Figure 3–47 Day-ahead forecast accuracy for each wind generation scenario

MAE is sometimes a misleading statistic as it normalizes all error to the nameplate capacity. Large differences between actual and forecast wind generation at lower levels of production are reduced in "appearance" when divided by nameplate capacity. In absolute terms, there will be many hours with significant differences between forecast and actual wind. Figure 3–48 illustrates hourly forecast and actual wind generation for randomly selected seven-day periods for the 20% Queue + Best Sites Onshore scenario.

The graphs show that the day-ahead forecasts provided with the mesoscale wind production data, and representing the state of the commercial art for wind generation forecasting, track the trends in the actual wind generation quite well. Closer inspection, though, shows some hours with very large errors. On the chart for the week in June, for example, actual wind generation is under-forecast by over 3000 MW for a few hours just prior to June 20th. In the October chart, over-forecasts of a similar magnitude are seen in the first hours of the record.

The production simulations can help reveal the significance of these errors with respect to system reliability and economics. Going forward, there are some significant outstanding questions regarding use of wind generation forecasts in the various operational contexts. In wholesale energy markets, for example, wind generation scheduled only in real-time or in short-term markets has the effect of ensuring over-commitment in the day-ahead market. On the other hand, over-forecasting of wind generation in the day-ahead reliability commitment may pose risks to system security.

These questions are now beginning to be addressed as the amount of wind generation becomes visible in energy markets and other operating regimes.

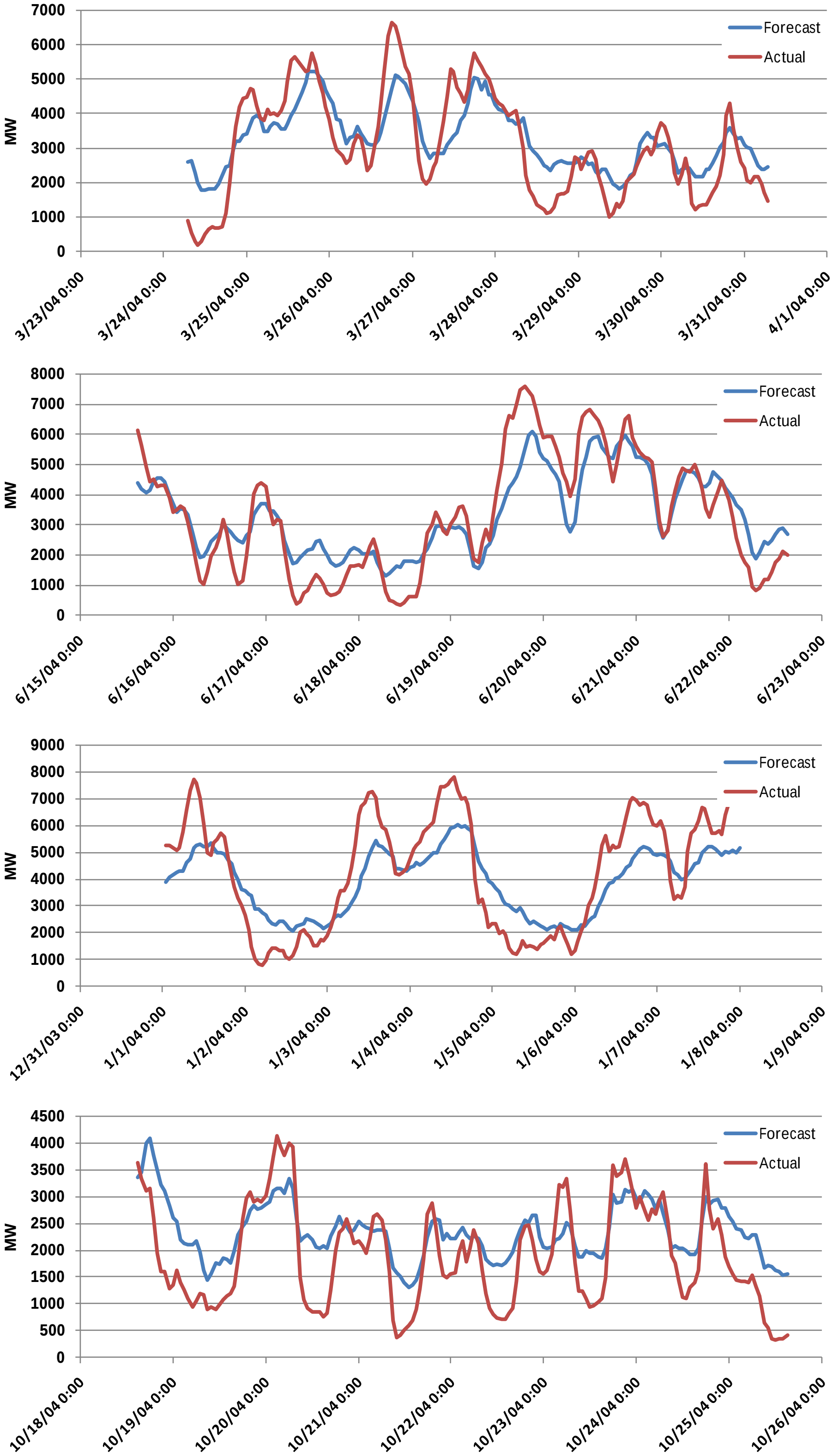


Figure 3–48 Day-ahead forecast and actual wind generation for selected weeks from each season; “20% Queue + Best Sites Onshore” scenario

3.2.3 Hour-Ahead

At one-hour horizons, “persistence” forecasts have been shown to be as statistically accurate as those based on more sophisticated techniques or atmospheric modeling. Persistence forecasts simply assume that things will not change – the forecast for the next interval is what is measured in the current interval.

Persistence forecasts are also simple to generate, and therefore are used in this study as a proxy for short-term wind generation forecasts. While the overall accuracy, as mentioned above, is good relative to other methods, they are of limited use in volatile wind conditions that may lead to large ramps in wind generation. Research is ongoing on special techniques for forecasting these conditions and better predicting large changes in wind generation. For purposes of this study, though, persistence is used due to its simplicity and the lack of hard data with respect to current or future ramp forecasting accuracy.

For 1-hour persistence, the forecast is the current hour’s value, and any changes from the current hour are directly equal to the forecast error. Previous views of the hourly changes are also characterizations of the 1-hour persistence forecast error. The chart in Figure 3–49 (which is identical to the chart in Figure 3–28) shows the distribution of all hourly errors for the 20% scenarios.

A more useful representation of persistence forecast errors is shown in Figure 3–50. In this chart, the errors are grouped by hourly production level, as with the ten-minute data earlier in this section. The expected error changes with production level and the empirical data can be simply approximated with a quadratic expression.

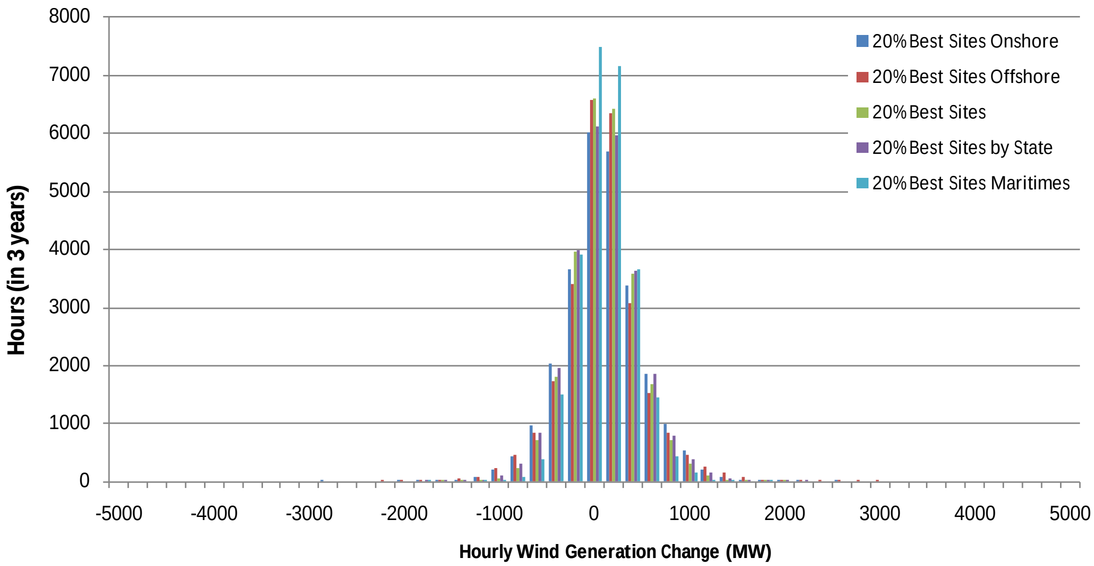


Figure 3–49 Distribution of 1-hour persistence forecast errors for 20% wind generation scenarios

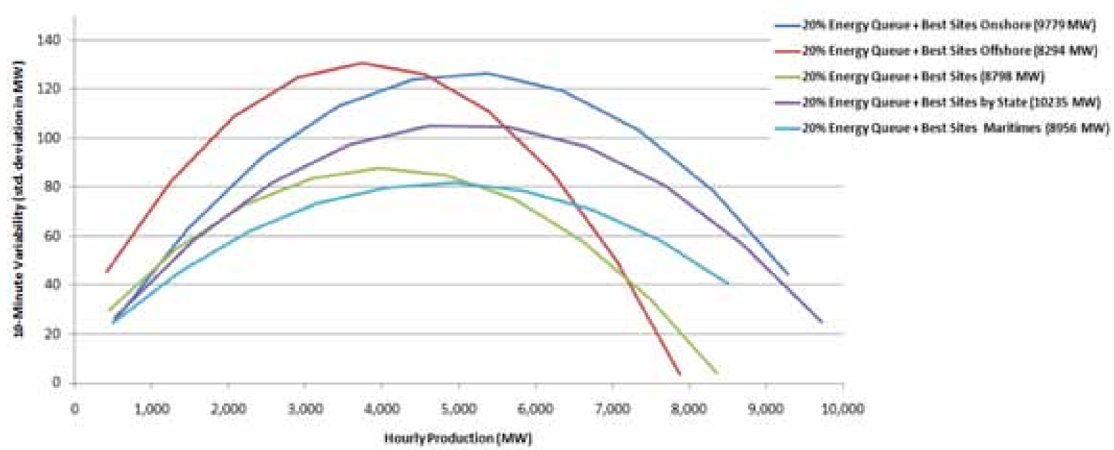


Figure 3–50 Expected 1-hour persistence forecast error as function of current production level for 20% scenarios

3.2.4 Very Short Term

Persistence forecasts over very-short term intervals are statistically more accurate than those over an hour. The charts characterizing wind generation changes over ten-minute intervals, appearing earlier as Figure 3–43, Figure 3–44, and Figure 3–45 in the discussion of variability, also characterizes expected forecast error over a ten-minute interval as a function of production level. These will be used later in the examination of incremental regulation and within-hour flexibility requirements.

3.3 Statistical Characterization Observations and Conclusions

The observations and conclusions here are made on the basis of three years of synthesized meteorological and wind production data corresponding to calendar years 2004, 2005, and 2006. In some senses, the sample size is very adequate, as the behavior of wind generation under many types of weather regimes is embedded in the dataset. In other respects, though, there may be some inadequacies. For example, inter-annual variability is known to be an important question for wind generation. With a limited sample size in terms of the number of years represented, there is no way to tell from the dataset alone whether annual energy production, for instance, is lower, higher, or about equal to what might be expected annually over the life of a wind project. Other resources, such as long-term meteorological records, would need to be consulted to provide insight into these types of questions.

The wind generation scenarios defined for this study show that the winter season in New England is when the highest wind energy production can be expected. As is the case in many other parts of the U.S., summertime is the “off-season” for wind generation.

The capacity factors for all scenarios follow the same general trend. Seasonal capacity factors above 45% in winter are observed for several of the scenarios. In summer, capacity factors drop to less than 30%, except for those scenarios that contain a significant share of offshore wind resources.

Based on averages over the entire dataset, seasonal daily patterns in both winter and summer exhibit some diurnal behavior. Winter wind production shows two daily maxima, one in the early morning after sunrise, and the other in late afternoon to early evening. Summer patterns contain a drop during the nighttime hours prior to sunrise, then an increase in production through the morning hours. It is enticing to think that such patterns could assist operationally with morning load pickup and peak energy demand, but the patterns described here are averages of many days. The likelihood of any specific day ascribing to the long term average pattern is small.

The net load average patterns by season reveal only subtle changes from the average load shape. No significant operational issues can be detected from these average patterns. At the extremes, the minimum hourly net load over the data set is influenced substantially. In one of the 20% by energy scenarios, the minimum net load drops from just about 10 GW for load alone to just over 3 GW. The very substantial additional turn-down on that particular day would be very noticeable operationally (and is evaluated directly in the hourly production simulations).

The day-ahead forecasts developed for each scenario from information in the NEWRAM dataset show an overall forecast accuracy of 15% to 20% Mean Absolute Error (MAE). This is consistent with what is considered the state of the commercial art. Day-ahead forecasts for all scenarios are important since they will be used directly in the hourly production simulations, and represent the major source of uncertainty attributable to wind generation.

Shorter-term forecasts also factor into operations. For reserves, the most important of these are the short-term hour ahead and ten-minute ahead forecasts. The process for generating these normally uses persistence, which assumes that there will be no change in wind generation over the forecast horizon. Persistence has been shown to be as statistically accurate as forecasts based on skill and sophistication (though skill-based forecasts may be much better during periods of predictable changes). The various statistical characterizations developed to portray the variability and short-term uncertainty of the aggregate wind generation in each scenario are also critical inputs to the analysis of operating reserve impacts in the next chapter.

4 Impact on ISO-NE Operating Reserves

4.1 General

The objective of this portion of the analysis is to evaluate how various levels of wind generation might impact ISO-NE policies and practices for operating reserves. Currently, ISO-NE defines three categories of operating reserve:

- 10-minute spinning reserve – TMSR
- 10-minute non-spinning reserve – TMNSR
- 30-minute operating reserve – TMOR

The ten-minute reserve requirement is based on the largest credible single contingency[68], which varies with system conditions; usually 50% (but sometimes as low as 25%) of the contingency amount is carried as spinning reserve (TMSR), and 50% as 10-minute non-spinning reserve (TMNSR). The 30-minute operating reserve (TMOR) requirement is 50% of the second largest credible contingency.

The dynamic nature of the ISO-NE reserve requirements was difficult to model directly in the production simulations, so an approximation was derived with the guidance of ISO-NE staff. For the calculations here, and in the production simulations described later, procurement of reserves was assumed to be a function of day type and time of day, as follows:

- 0700-2300 Weekdays
  - Total 10 minute reserve = 1500 MW, 750 of which will be 10-minute spin (750 MW TMSR, 750 MW TMNSR)
  - 30-minute reserve (TMOR): 750 MW
  - The total 10-minute and 30-minute reserve would be 2250 MW
- 2300-0700 Weekdays and all hours Weekends.
  - Total 10 minute reserve: 1300 MW; 650 of which will be 10-minute spin (650 MW TMSR, 650 MW TMNSR)

[68] "Credible" is based on a set of stress tests defined by NPCC and augmented by ISO-NE for the purposes of determining operating reserve contingencies to be planned for. More severe "extreme" contingencies may require additional operator and/or automatic intervention including shedding of firm load.

- 30-minute reserve (TMOR): 650 MW
- The total 10-minute and 30-minute would be 1950 MW

ISO-NE procures regulation capacity separately in the ancillary services market, but the amount of regulation carried is counted toward TMSR. The amount needed is based on careful analysis of load behavior, and varies by season, day type, and hour. The regulation schedule for weekdays in 2008 is provided in Table 4–1 as an illustration.

Table 4–1 ISO-NE 2008 Regulation Schedule for Weekdays

day	hour	jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec
week	1	90	90	90	50	50	90	90	90	50	50	90	90
week	2	30	30	30	50	50	30	30	30	30	30	30	30
week	3	30	30	30	50	50	30	30	30	30	30	30	30
week	4	30	30	30	50	50	30	30	30	30	30	30	30
week	5	30	30	30	50	50	30	30	30	30	30	30	30
week	6	140	140	140	100	100	150	150	150	100	100	140	140
week	7	170	170	170	200	200	180	180	180	180	180	170	170
week	8	170	170	170	170	170	180	180	180	150	150	170	170
week	9	100	100	100	100	100	110	110	110	80	80	100	100
week	10	50	50	50	90	90	50	50	50	50	50	50	50
week	11	50	50	50	90	90	50	50	50	50	50	50	50
week	12	50	50	50	90	90	50	50	50	50	50	50	50
week	13	50	50	50	90	90	50	50	50	50	50	50	50
week	14	50	50	50	90	90	50	50	50	50	50	50	50
week	15	50	50	50	90	90	50	50	50	50	50	50	50
week	16	50	50	50	90	90	50	50	50	50	50	50	50
week	17	80	80	80	90	90	80	80	80	70	70	80	80
week	18	80	80	80	110	110	80	80	80	80	80	80	80
week	19	80	80	80	110	110	80	80	80	80	80	80	80
week	20	80	80	80	110	110	80	80	80	80	80	80	80
week	21	80	80	80	110	110	80	80	80	80	80	80	80
week	22	110	110	110	150	150	120	120	120	110	110	110	110
week	23	160	160	160	170	170	160	160	160	160	160	160	160
week	24	160	160	160	170	170	160	160	160	160	160	160	160

Hourly regulation varies from a low of 30 MW (overnight on weekends) to a high of 200 MW (spring morning load pickup). Over all hours of 2008, the weighted average hourly regulation is about 80 MW.

Wind generation will increase the real-time variability and short-term uncertainty of the net load against which other resources are scheduled and dispatched.

4.2 Methodology

Chronological production simulations at hourly resolution have become the standard approach for assessing wind integration impacts. Effects of wind inside of the hour on regulation, balancing, and reserves in general cannot be directly evaluated at that granularity. Consequently, statistical techniques have been developed for application to hourly and higher resolution wind and load data to estimate the impacts within the hour.

4.3 High-resolution analysis

Statistical analysis of wind and load data is employed to determine how much additional regulation capacity would be required to maintain CPS1 and CPS2 metrics in each of the wind scenarios. The data available for this analysis consists of high-resolution (10-minute interval) load and wind generation data, compiled for the study from actual load data for 2004, 2005, and 2006, and synthetic wind generation data from the ISO-NE mesoscale data. Additionally, one-minute resolution data for ISO-NE load provided for an earlier study was used.

Additionally, wind production data at 1-minute resolution was synthesized for a portion of the analysis. The procedure used is based on previous high resolution measurements of large wind plants and groups thereof that reveal a normally-distributed random behavior of faster variations about a trend.[69]

ISO-NE operating structure forms the primary backdrop for the analysis. The movement of generation in real-time operations is assumed to be in response to:

- The sub-hourly market, where clearing points are determined in advance based on short-term (10 to 20 minute) forecasts of demand and participating generation is economically dispatched, or
- Automatic Generation Control (AGC) signals to units participating in the regulation market to correct for Area Control Error (ACE) between sub-hourly market intervals

The first objective of the statistical analysis is to analyze the fast fluctuations of wind generation relative to similar variations in the load. Using the one-minute resolution load data as a reference, the fast variations are computed as the difference between the data and a twenty minute rolling average window to the 1-minute data (10 samples before and 10 samples following). Results are shown in Figure 4–1.

[69] Wan, Yih-Huei and Bucaneg, Demy “Short Term Fluctuations of Large Wind Power Plants” NREL/CP-500-30747, January 2002

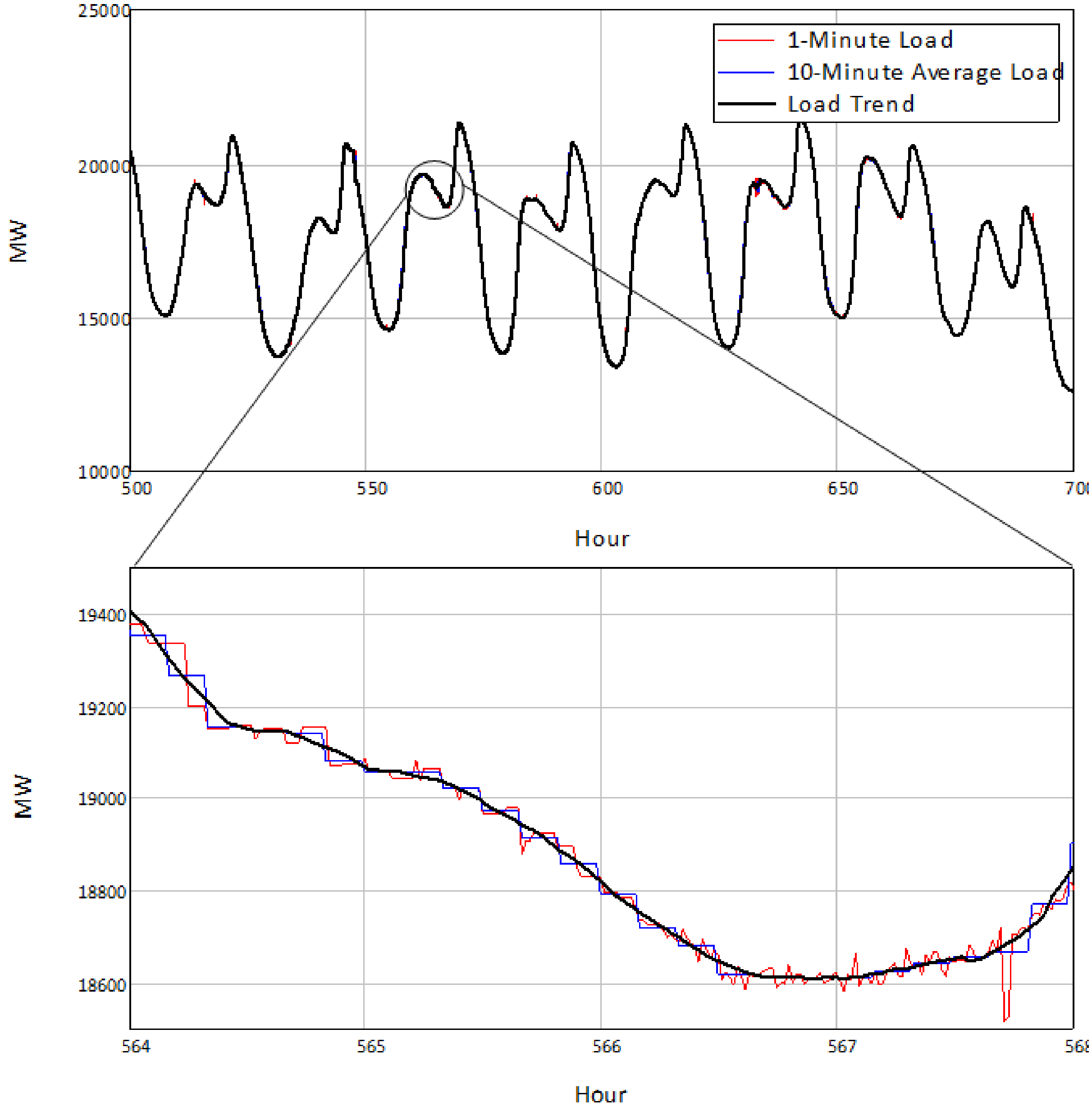


Figure 4–1 Six-day sample of 1-minute load data with trend and ten-minute averages for variability analysis

Of interest here is the deviation of the one-minute load data from the two curves, for if the constructed curves are assumed to be proxies for the variability that is compensated for by movements of generation in the sub-hourly market, the difference is what drives the need for regulation. The distributions of the differences over the 100,000 samples of one-minute data analyzed are shown in Figure 4–2. Both distributions are normal with a mean of zero, so the standard deviation is an appropriate characterization.

The requirement for regulation capacity has been approximated as a multiple of the standard deviation of the variability in this time scale. A factor of three would encompass (magnitude-wise) 99.8% of all deviations in the sample. Using this factor, the regulation capacity inferred from the statistics is 76 to 141 MW. Note that this accounts for the variability of the load only. Not included are additional deviations due to uninstructed generation movements, and ramping behavior of generation participating in the sub-hourly energy market. The regulation schedule described in Section 4.1 above accounts these factors as well as the changing variability of load with season, day type, and hour.

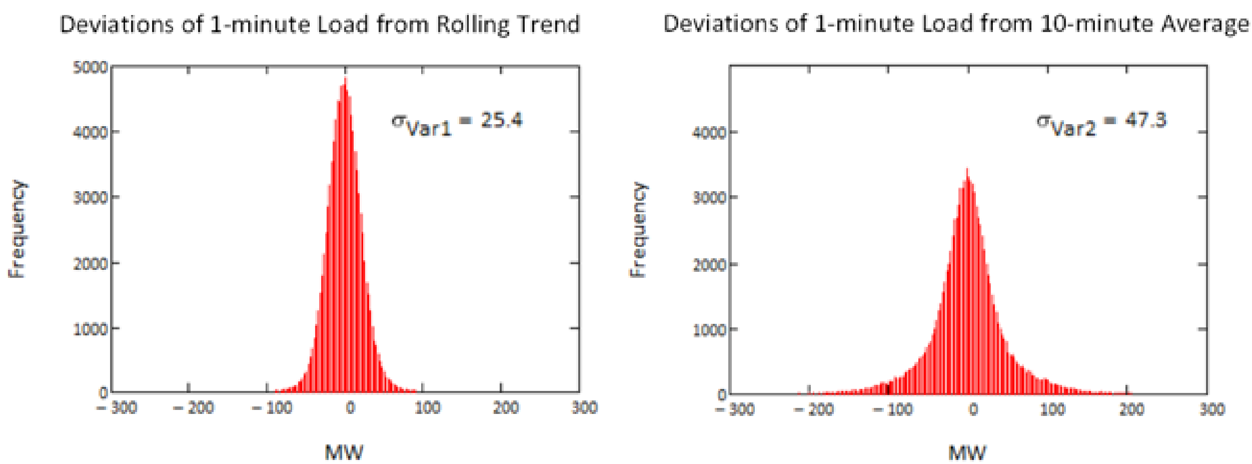


Figure 4–2 Deviations of ISO-NE 1-minute load from (l) trend and (r) ten-minute average

The ISO-NE simulated wind generation data used for this study is of 10-minute resolution, so it cannot be used directly to assess impacts of faster variations. However, extensive measurement data with time resolution down to seconds has been collected by NREL over the past decade, and other high-resolution data for wind generation has been obtained from energy management system (EMS) archives. Two observations are extracted from this measurement data for use here:

- Using the 20-minute rolling average window (used above), the standard deviation of the wind generation variations around this trend are around 1 to 2 MW for a 100 MW wind plant.
- The fast variations from a wind plant are statistically uncorrelated with similar variations from other wind plants and with those from aggregate load, and therefore can be considered in this time frame as random independent variables

The effect of the fast variations of wind generation can then be easily estimated. With 8800 MW of wind generation, approximately the amount of the 20% scenarios, the aggregate variability (i.e. deviation from the 20-minute trend) of the total wind generation can be calculated using the 2 MW assumption above:

$$\sigma_{wind} := \left(\sqrt{\frac{8800}{100} \cdot 2^2}\right) = 18.8 \quad \text{MW} \qquad \text{Eq. 1}$$

And, because these variations are uncorrelated with those in load, using the standard deviation of load variations shown above in Figure 4–2, the standard deviation of the variability for net load (i.e. load net of wind generation) is calculated as:

$$\sqrt{\sigma_{Var1}^2 + \sigma_{wind}^2} = 31.6 \quad \text{MW} \qquad \sqrt{\sigma_{Var2}^2 + \sigma_{wind}^2} = 50.9 \quad \text{MW} \qquad \text{Eq. 2}$$

where the first equation uses the rolling trend approximation for sub-hourly market response to load and the second uses ten-minute averages. In either case, the effect of the fast fluctuations in wind generation is quite small; the standard deviation of variability is increased from 25.4 to 31.6 MW or from 47.3 to 50.9 MW.

Over longer time scales – tens of minutes up to hours – wind generation exhibits variations that are of a markedly different character than that of load. In general, load changes over these time periods are relatively predictable, owing to both aggregation effects and a high level of familiarity based on history and heuristics. In this part of the analysis, it will be assumed that short-term forecasts of load are nearly perfect, and that sub-hourly energy markets will dispatch the necessary capacity to balance load over these intervals.

The same notion is extended to wind generation, except with recognition that short-term forecasts may exhibit appreciable error. Stated another way, sub-hourly markets will provide the necessary maneuverable capacity to balance forecast load and forecast wind generation; errors in these forecasts (for wind only, given the assumptions) will increase the regulation burden.

Figure 4–3 provides an illustration. The forecast for interval H2+20 is based on the observed wind generation during a previous interval or series of intervals, in this case the observed wind from H2+10. In the analysis here, it is assumed that the forecast for interval H2+20 is assimilated into the sub-hourly energy market clearing. The difference between the actual wind generation that appears in the interval and the forecast value will combine with the other deviations in load and generation. The aggregate of these deviations drives the requirement for regulation.

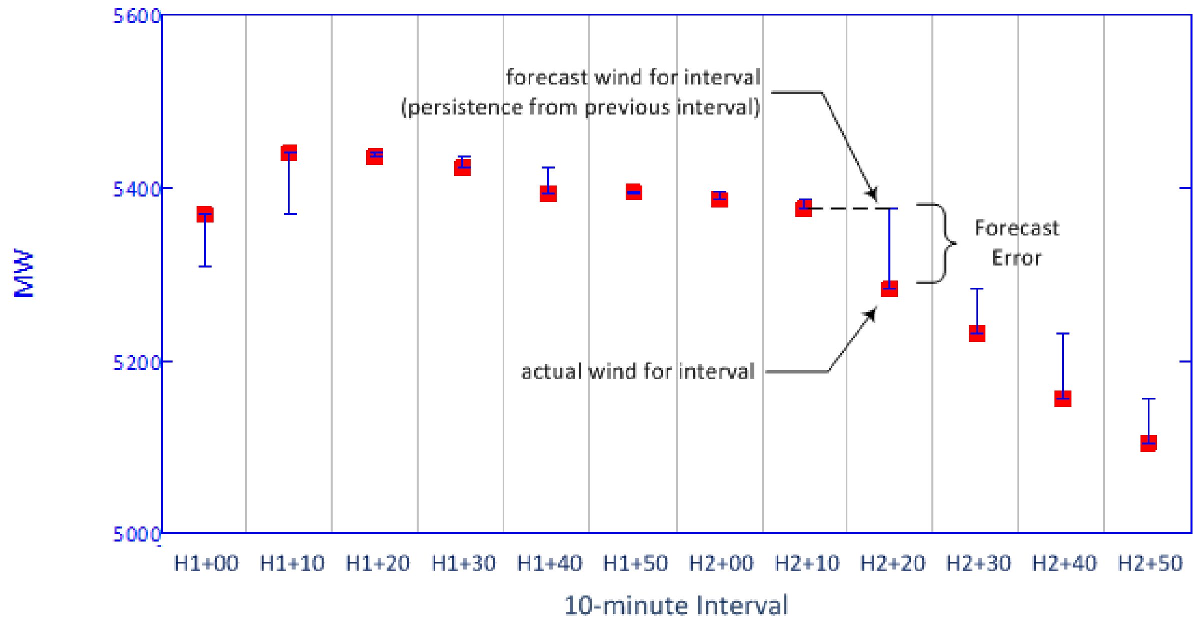


Figure 4–3 Short-term persistence forecasting for 10-minute wind generation.

Two short-term “forecast” methods were evaluated for the synthetic wind generation for three wind scenarios. The first method uses a simple persistence assumption: “Average wind generation for the next ten-minute interval will be identical to the current interval.” The second method uses a sophisticated regression/curve-fitting/prediction method built into the analysis tool used here to mimic a more “intelligent” approach that presumably would outperform the persistence assumption during periods with sustained change in wind production.

After applying both methods to the data, it was found that over the sample data year (2005), the persistence method was more accurate, with a mean absolute error of 3.4% versus 4.7% for the regression/extrapolation method. Consequently, the persistence method was used for the remainder of the analysis.

Owing to the large sample of synthetic wind generation data, the expected “errors” in the persistence forecast can be mathematically characterized. Figure 4–4 shows the change in production between 10-minute intervals (i.e. the persistence forecast error) for the aggregate wind generation in the three scenarios corresponding to 8800 MW 4000 MW, and 1100 MW of wind generation (all plotted on the same scales for easier comparison). The charts are creating by plotting x-y pairs of points where x is wind generation in the current interval “i”, and the y value is equal to wind generation in the next interval minus wind generation in the current interval.

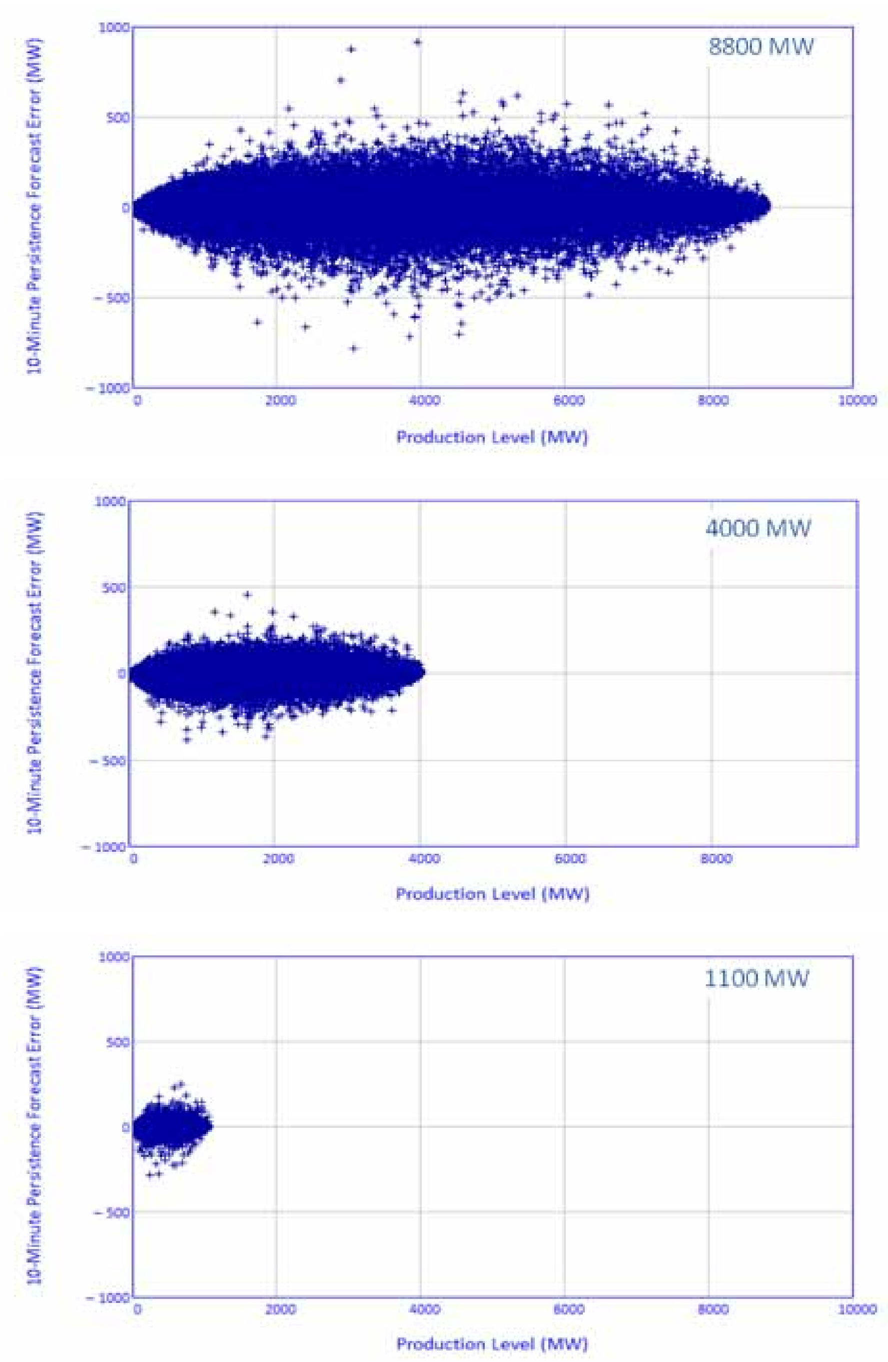


Figure 4–4 10-minute variability of three illustrative wind scenarios used for high –resolution analysis

Another view of this same variability is presented in Figure 4–5. Here, each of the changes (or forecast errors) is grouped in ten "bins" or deciles of production from 0 to 1.0 per unit of name plate rating. Then, the standard deviation of the (normal) distributions in each of the deciles is computed and plotted.

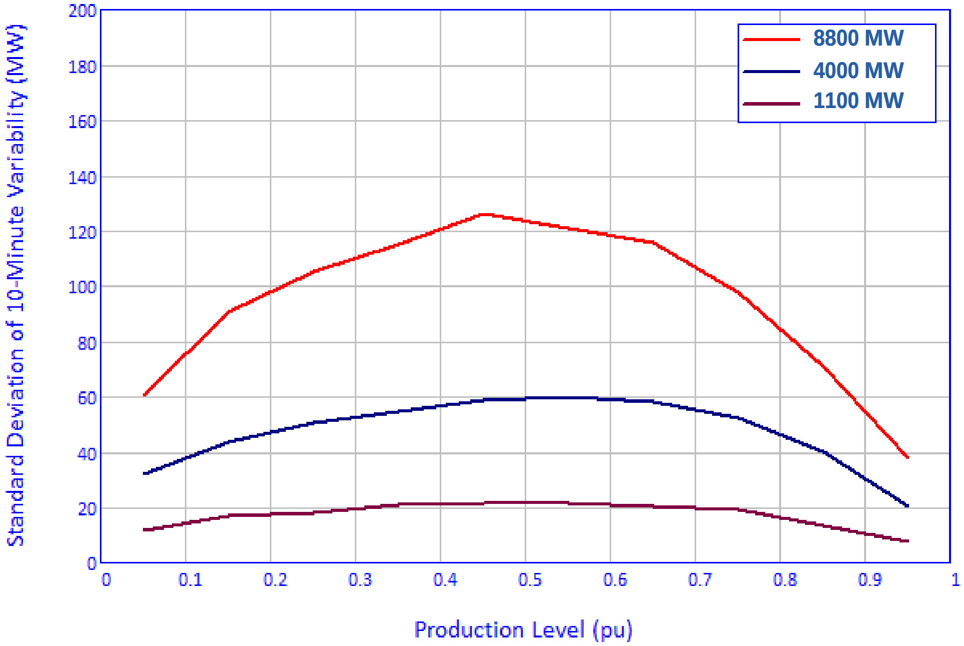


Figure 4–5 10-minute variability of illustrative wind scenarios with hourly average production level; empirical data, in MW

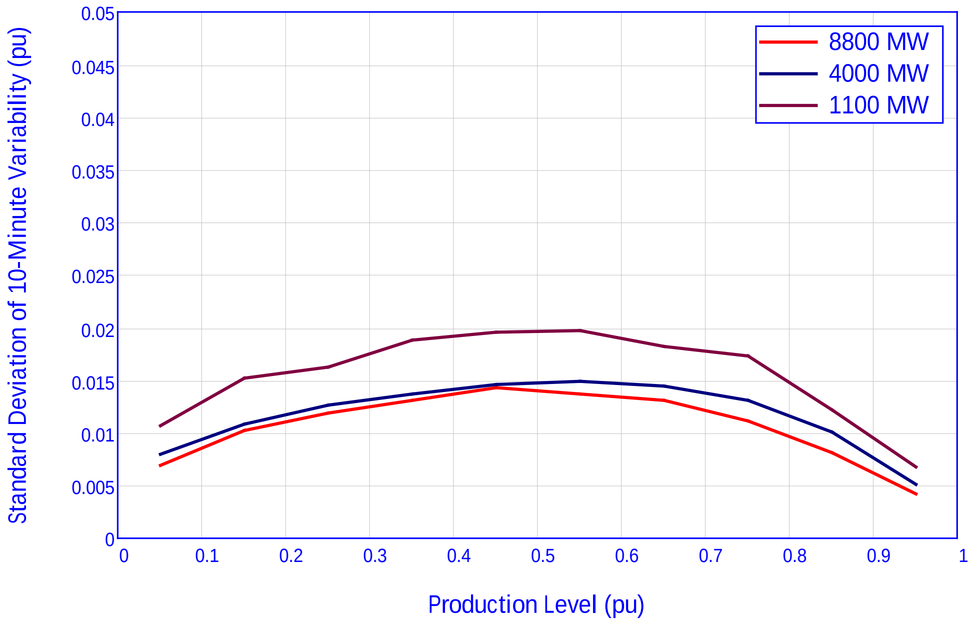


Figure 4–6 10-minute variability of illustrative wind scenarios with hourly average production level; empirical data, per-unit of aggregate nameplate capacity for each scenario

The scenarios analyzed above are for illustration, and are representative of the penetration levels examined in this study. In the analysis to come, the specific variability characteristics of each scenario are computed and then used in estimations of incremental regulation requirements. Characterization of the variability in this manner captures the uniqueness of each defined scenario; those with large concentrated wind generation facilities will show more variability than scenarios with much more dispersed plants. Effects of geographic diversity, as another example, can be seen in Figure 4–6, where the variability at 10 minute intervals, expressed as a percentage of total capacity, declines as the number of individual turbines in the scenario (and the total installed capacity) increases.

The curves can be approximated well with a simple quadratic expression. The utility of this approximation is that the variability can be defined by the current or forecast production level. This provides a method to procure the appropriate amount of additional regulating reserves as wind generation varies over hours or days.

4.4 Results with hourly data

The estimated operating reserve requirements for each wind generation scenario are described here. The previous discussion feeds into the regulation analysis. Beyond regulation, other calculation techniques using 10-minute wind and load data along with production simulations results from MAPS are used to assess how the ISO-NE operating reserve categories would be impacted by wind generation.

4.4.1 Regulation – Hourly Approximations

Incremental regulation requirements for each scenario are estimated as a function of the variability of ISO-NE load as implied from the scheduled regulation (see Table 4–1) and the variability of the wind generation as defined by the 10-minute “persistence forecast error” characterizations, as shown in Figure 4–7 for each of the study wind generation scenarios.

Equations which approximate the 10-minute variability as functions of hourly production level for each wind generation scenario in the study are shown in Table 4–2. These equations are graphically depicted in Figure 4–7.

Table 4–2 Approximate Equations for 10-minute variability

Scenario	Variability Approximation
20% Queue + Best Sites Onshore	$\sigma = [-4.67 \cdot 10^{-6}(HourlyWind^2) + 4.78 \cdot 10^{-2}(HourlyWind) + 1.91\,]\,MW$
20% Queue + Best Sites Offshore	$\sigma = [-7.44 \cdot 10^{-6}(HourlyWind^2) + 6.22 \cdot 10^{-2}(HourlyWind) + 1.20]\,MW$
20% Queue + Balanced Case	$\sigma = [-4.39 \cdot 10^{-6}(HourlyWind^2) + 3.54 \cdot 10^{-2}(HourlyWind) + 14.9\,]\,MW$
20% Queue + Best Sites by State	$\sigma = [-3.73 \cdot 10^{-6}(HourlyWind^2) + 3.80 \cdot 10^{-2}(HourlyWind) + 8.28\,]\,MW$
20% Queue + Best Sites Maritimes	$\sigma = [-3.05 \cdot 10^{-6}(HourlyWind^2) + 2.94 \cdot 10^{-2}(HourlyWind) + 10.3]\,MW$
14% Queue + Best Sites Onshore	$\sigma = [-6.61 \cdot 10^{-6}(HourlyWind^2) + 4.79 \cdot 10^{-2}(HourlyWind) + 3.85\,]\,MW$
14% Queue + Best Sites Offshore	$\sigma = [-7.33 \cdot 10^{-6}(HourlyWind^2) + 4.66 \cdot 10^{-2}(HourlyWind) + 7.54\,]\,MW$
14% Queue + Balanced Case	$\sigma = [-7.01 \cdot 10^{-6}(HourlyWind^2) + 4.34 \cdot 10^{-2}(HourlyWind) + 5.87\,]\,MW$
14% Queue + Best Sites by State	$\sigma = [-5.47 \cdot 10^{-6}(HourlyWind^2) + 3.99 \cdot 10^{-2}(HourlyWind) + 5.93\,]\,MW$
14% Queue + Best Sites Maritimes	$\sigma = [-5.27 \cdot 10^{-6}(HourlyWind^2) + 3.61 \cdot 10^{-2}(HourlyWind) + 4.41\,]\,MW$
9% Full Queue	$\sigma = [-1.14 \cdot 10^{-5}(HourlyWind^2) + 5.04 \cdot 10^{-2}(HourlyWind) + 1.80\,]\,MW$
2.5% Partial Queue	$\sigma = [-5.51 \cdot 10^{-5}(HourlyWind^2) + 6.60 \cdot 10^{-2}(HourlyWind) + 2.37\,]\,MW$

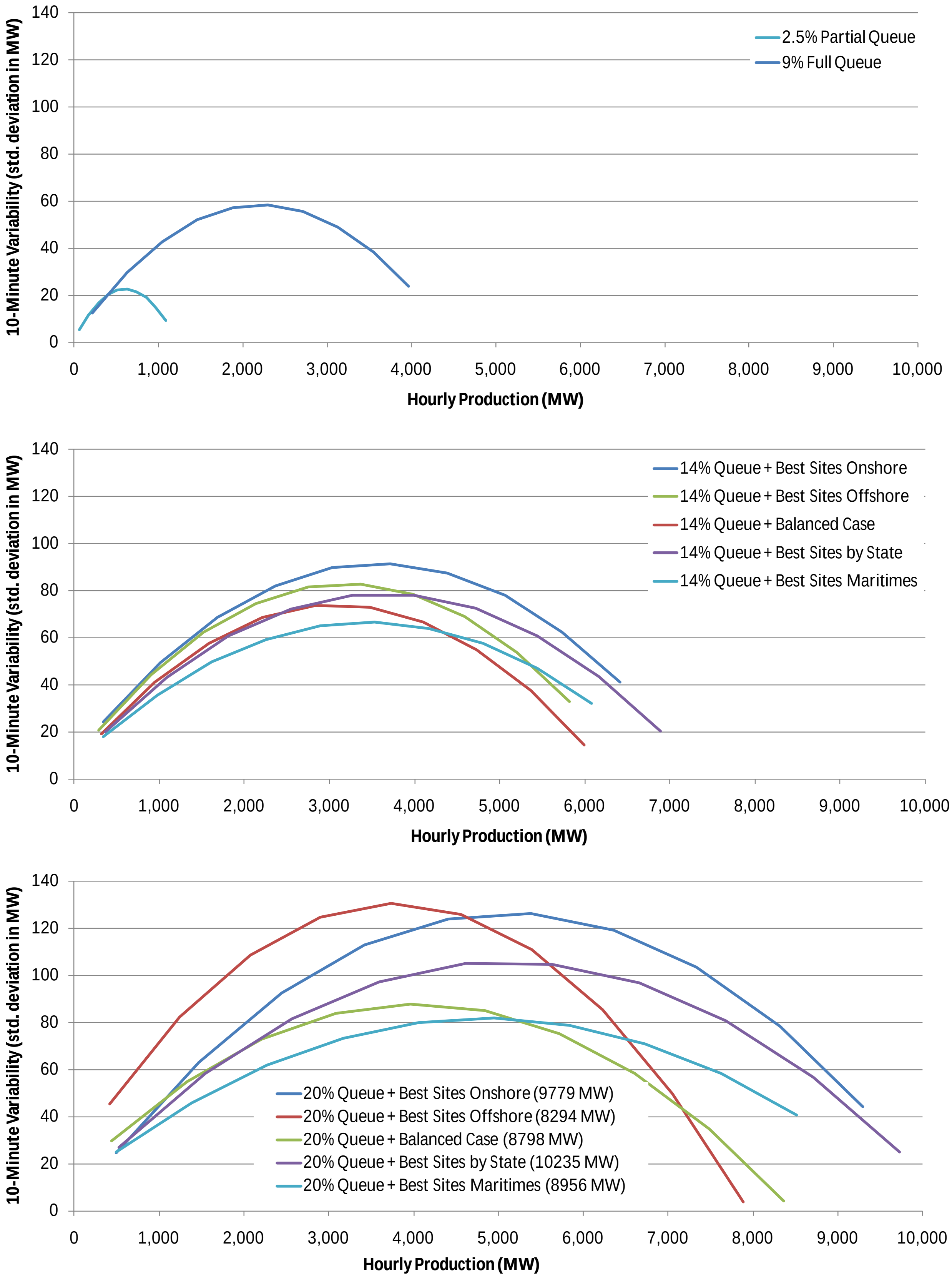


Figure 4–7 Quadratic approximations to empirical variability curves for study wind energy scenarios.

As mentioned previously, the variability of wind generation at this time scale is assumed to be uncorrelated with that of load, so a statistical combination of independent variables is appropriate. The calculation assumes that the total variability is the root mean square sum (RMS) of:

- The standard deviation of the load variability, assumed to be 1/3 of the regulation scheduled for the hour (encompasses 99.7% of all variations in the normal sample)
- The fast wind variability, taken as 2 MW per 100 MW of installed capacity. For each scenario, the total fast variability is the root-mean-square sum of the installed capacity divided by 100 times 2 MW squared. This component is included for completeness, but a very small contributor to the incremental regulation (per Equation 1).
- The longer-term wind variability or the difference between the short-term persistence forecast and the actual wind 10 minutes into the future. This error is taken as the variability from one 10-minute interval to the next and is a function of the expected hourly production level, i.e. the expected error is largest in the middle range of the aggregate production level per curves in Figure 4–7 above and the equations in Table 4–2.

Results of the calculations for all scenarios are shown in Table 4–3 through Table 4–5. The amount of additional regulation calculated for each hour depends on

- The amount of regulation carried for load alone. It should be noted that when more regulation is available, the incremental impact of wind generation is reduced due to the statistical independence of the variations in wind and load.
- The aggregate wind generation production level, since the statistics show that wind production varies more when production from 40 to 60% of maximum (Figure 4–7)

As can be seen in Tables 4-3 through 4-5, at 20% wind energy penetration, the average regulation requirement is estimated to increase from approximately 80 MW without wind, to a high of approximately 315 MW with 20% wind depending on the differences within the scenario. At lower penetration levels, the incremental regulation requirement is smaller. The hourly analysis indicates average regulation requirements would increase to a high of approximately 230 MW with 14% wind energy penetration. At 9% wind energy penetration, the average regulation would increase to approximately 160 MW. At the lowest wind penetration studied (2.5%); average required regulation capability would increase to approximately 100 MW.

The “Regulation – High Estimate” values apply a factor of 1.0 to the longer-term wind variability in the RMS calculation. A parallel analysis (described in 4.4.2) indicated that the results using this factor were likely conservative. Consequently, a “Regulation – Low Estimate” was computed by reducing the factor to 0.66. Because the regulation amounts vary based on the ISO-NE regulation schedule and the amount of hourly wind generation, the values reported are averages, maximums, and minimums. Distributions of hourly amounts for a full calendar year for a 20%, 14%, and 9% and 2.5% energy scenario are shown in Figure 4–8. Cumulative distributions for these scenarios are shown in Figure 4–9.

Table 4–3 Estimated Regulation Requirements for 20% Wind Scenarios

	Load	20% Queue + Best Sites Onshore	20% Queue + Best Sites Offshore	20% Queue + Balanced Case	20% Queue + Best Sites by State	20% Queue + Best Sites Maritimes
Regulation - High Estimate						
Maximum	200	433	442	335	380	321
Minimum	30	78	101	90	71	88
Average	82	290	313	234	249	221
Regulation - Low Estimate						
Maximum	200	328	333	272	297	264
Minimum	30	73	82	77	69	79
Average	82	211	224	175	186	167

Table 4–4 Estimated Regulation Requirements for 14% Wind Scenarios

	Load	14% Queue + Best Sites Onshore	14% Queue + Best Sites Offshore	14% Queue + Balanced Case	14% Queue + Best Sites by State	14% Queue + Best Sites Maritimes
Regulation - High Estimate						
Maximum	200	343	323	302	314	286
Minimum	30	76	62	64	62	75
Average	82	228	217	199	204	186
Regulation - Low Estimate						
Maximum	200	276	264	253	260	245
Minimum	30	68	59	60	60	68
Average	82	171	163	153	157	145

Table 4–5 Estimated Regulation Requirements for 9% and 2.5% Wind Scenarios

	Load	9% Full Queue	2.5% Partial Queue
Regulation - High Estimate			
Maximum	200	269	212
Minimum	30	50	37
Average	82	161	102
Regulation - Low Estimate			
Maximum	200	235	206
Minimum	30	50	37
Average	82	129	93

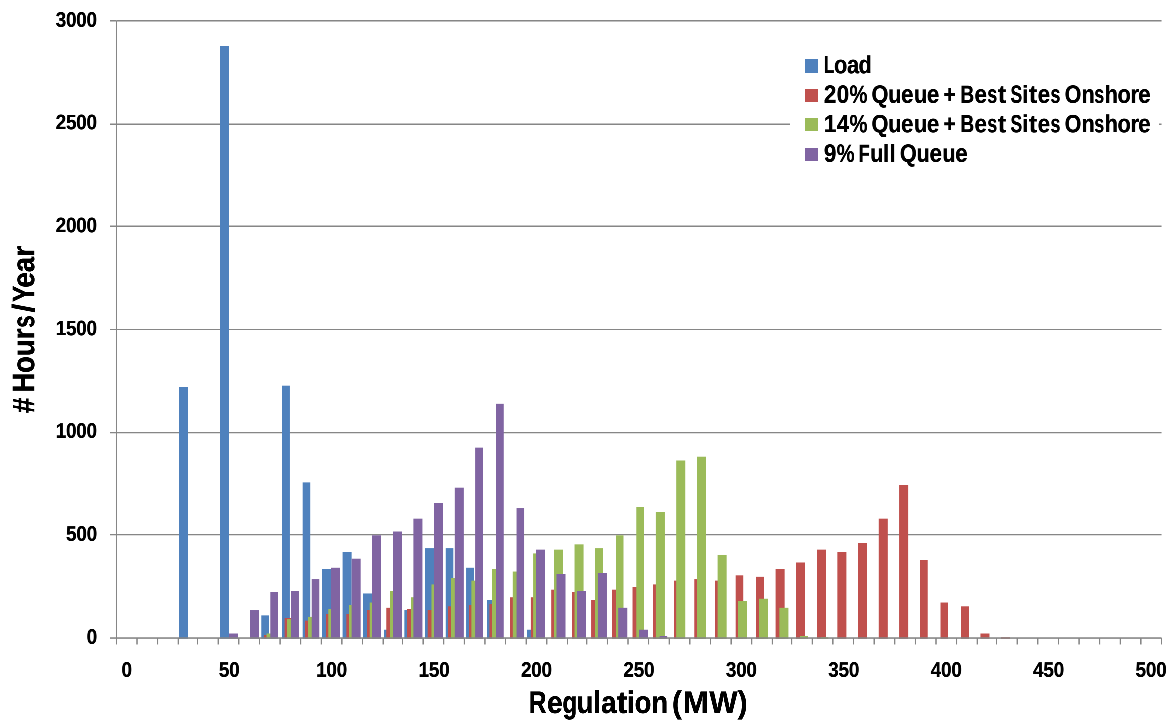


Figure 4–8 Distribution of hourly regulating requirements for ISO-NE load and selected wind generation scenarios

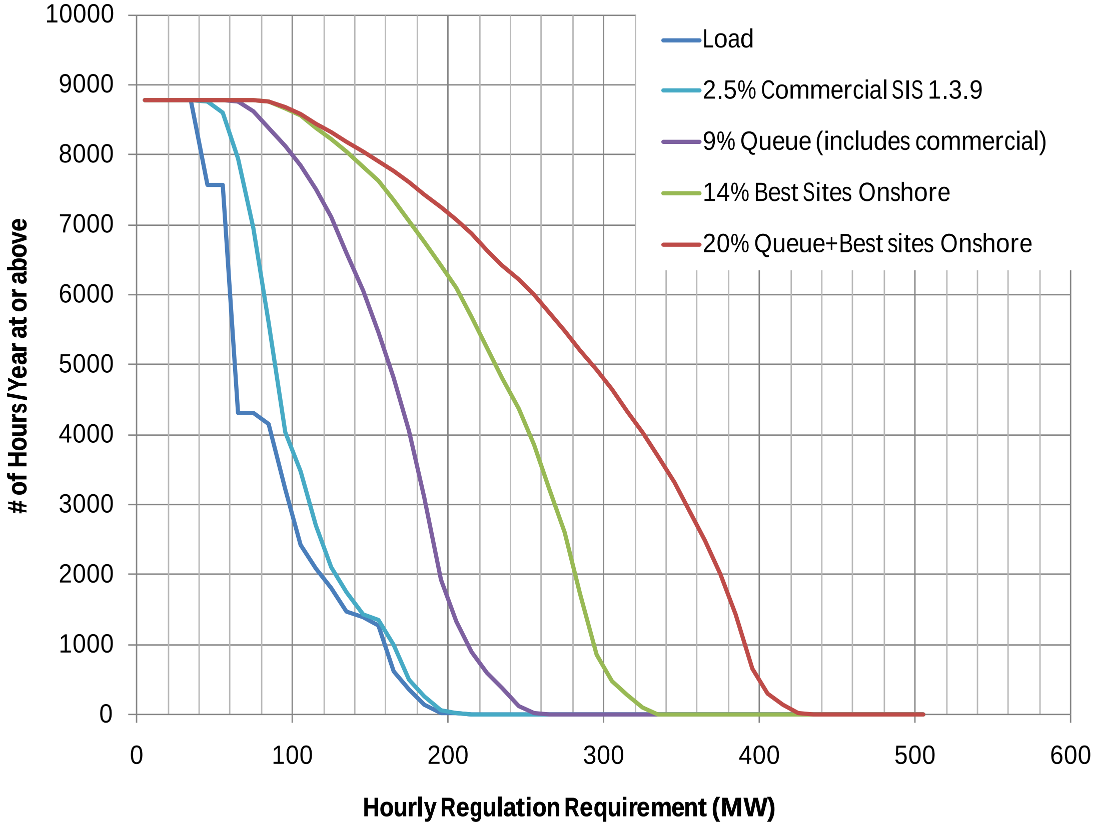


Figure 4–9 Duration curve of estimated hourly regulation requirements ("Regulation: High Estimate") for load and selected wind scenarios

Figure 4-9 shows regulation-duration curves for increasing levels of wind penetration. It shows the number of hours per year where regulation needs to be equal to or greater than a given value. For example, the dark blue curve (the left-most curve) shows that between 30 MW and 190 MW of regulation is required for load alone. The 2.5% Partial Queue scenario (the light blue line to the right of the load alone curve) increases the regulation requirement to between approximately 40 MW and 210 MW; the overall shape tracks that of the load alone regulation requirement curve. In the higher wind penetration scenarios, this minimum amount of required regulation capacity increases and the average amount of regulation required increases such that the shapes of the curves no longer track that of the load alone curve—this is indicative that the increased regulation capacity will likely be required to be utilized more frequently. The purple curve (the middle curve) shows that between approximately 50 MW and 270 MW of regulation is required with 9% wind energy penetration. The yellow and red curves (to the right of the 9% wind penetration curve just discussed) show that the required regulation increases to between approximately 75 MW and 345 MW and to between approximately 80 MW and 430 MW, respectively.

Based on the assumptions used in this analysis, the key factor in the additional regulation required for each scenario is the variability from one 10-minute interval to the next. The variability of each scenario on this time scale is a complicated function of the scenario definition and meteorology; predicting the variability of a given deployment of hundreds of wind turbines on this time scale is not possible. However, the high-resolution wind production data developed for this study allows the variability of a defined scenario to be characterized after the fact, facilitating this analysis.

The approach is likely not that different from that which will be used by ISO-NE as wind generation becomes more visible in power system operation. Archived measurements from the EMS could serve a role similar to that of the NEWRAM data.

4.4.2 Regulation Analysis Using Historical ACE Records

With guidance and assistance from ISO-NE operating personnel, additional analysis of regulation requirements was conducted with high-resolution (1-minute) load and synthesized wind data. The approach utilized ACE (area control error) values from the EMS archive for a calendar year. To this, the hourly scheduled regulation and the short-term wind generation persistence forecast were added as vectors.

For each 1-minute interval, a new ACE value was computed by adding the 10-minute wind generation forecast error to the ACE for load alone from the historical record. This augmented ACE value assumes that no regulation capacity is deployed to compensate for the difference between the actual wind generation and the amount that is scheduled into the sub-hourly energy market.

The average ACE for load and ACE net load are then calculated for each hour based on the sixty 1-minute samples. Each hour is then grouped according to some defined criteria – e.g. all weekday hours ending 0100, or all hours in the year where the scheduled regulation for load is X MW. In each grouping the ratio of regulation scheduled for load to the ACE for load is calculated. ACE for net load is then multiplied by that ratio to calculate the new regulation amount for net load in a particular grouping of hours.

The process used here first groups all hours by the amount of regulation being carried for load. Then, within each group, the data is sorted by the wind generation production level. Regulation-to-ACE ratios are calculated for each of these sub-groups. Results for the “20% Best Sites Onshore” scenario are shown in Figure 4–10. Values for the chart are found in Table 4–6 along with the average new regulation amounts for each level of scheduled regulation.

Table 4–6 Computed increases in Hourly Regulation Requirements from analysis of ACE

	Scheduled Regulation															
Wind Production Level	**30**	**50**	**70**	**80**	**90**	**100**	**110**	**120**	**130**	**140**	**150**	**160**	**170**	**180**	**200**	**Average**
0-999	1.21	1.31	1.10	1.19	1.23	1.11	1.11	1.10	1.16	1.04	1.08	1.04	1.04	1.10		**113%**
1000-1999	1.43	1.57	1.26	1.47	1.46	1.19	1.31	1.22	1.17	1.17	1.23	1.27	1.27	1.22	1.10	**129%**
2000-2999	1.78	1.79	1.33	1.55	1.67	1.38	1.32	1.33	1.47	1.30	1.40	1.47	1.31	1.31	1.40	**145%**
3000-3999	1.81	1.93	1.43	1.84	1.75	1.54	1.63	1.56	1.44	1.34	1.52	1.50	1.43	1.39	1.21	**155%**
4000-4999	2.29	2.03	1.31	1.82	2.21	1.41	1.52	1.49	1.56	1.20	1.48	1.65	1.33	1.48	1.25	**160%**
5000-5999	2.01	2.02	1.31	1.91	1.88	1.64	1.57	1.72	1.28	1.51	1.48	1.45	1.43	0.93	1.41	**157%**
6000-6999	1.73	2.04	1.50	2.02	1.73	1.53	1.70	1.52	1.29	1.31	1.28	1.37	1.44	1.50	1.12	**154%**
7000-7999	1.70	1.70	1.24	1.61	1.46	1.66	1.40	1.35	1.10	1.18	1.29	1.60	1.35	1.55		**144%**
8000-8999	1.30	1.37	1.16	1.25	1.38	1.23	1.10	1.01	1.16	1.70	1.11	1.13	1.14	1.07		**122%**
Average - % of Load Only	**170%**	**175%**	**129%**	**163%**	**164%**	**141%**	**141%**	**137%**	**129%**	**130%**	**132%**	**139%**	**130%**	**128%**	**125%**	
Average - MW	**51**	**88**	**90**	**130**	**148**	**141**	**155**	**164**	**168**	**183**	**198**	**222**	**222**	**231**	**250**	

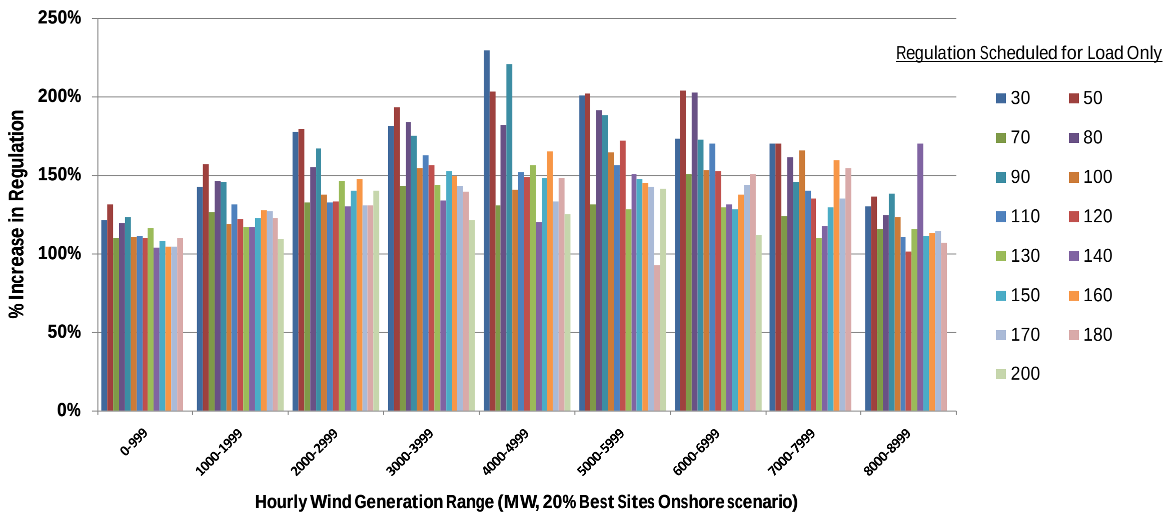


Figure 4–10 Hourly regulation requirements from ACE analysis methodology for "20% Queue + Best Sites Onshore" scenario; shown by hourly wind production level for each quantity of scheduled load regulation

Some points and observations regarding the analysis using ACE data:

- While an entire year of 1-minute data was used in the analysis, the sorting resulted in a few groupings with little or no data. For example, there were no hours with 200 MW of scheduled regulation and wind generation either 0-999 or 8000-8999 MW, so the empirical basis for these groupings could be questioned.
- The load hours were sorted by scheduled regulation only, so hours from different day-types and seasons were intermingled. This was done to increase the sample of hours in each of the defined groupings, but has the disadvantage of grouping hours with potentially different load compositions and characteristics.
- As can be seen from the column and row averages in Table 4–6, for the "20% Queue + Best Sites Onshore" scenario, the regulation amounts increase, on average, roughly 50% over the amounts currently scheduled for load. As expected the impact is higher when

wind generation is in the mid-range of aggregate nameplate production, with smaller impacts at both lower and higher levels.

The purpose of this analysis was to provide a check on the methodology using hourly data described in Section 4.4.1. A comparison of Table 4–6 with Table 4–3 through Table 4–5 suggests that the hourly methodology described earlier may be conservative. It should be recognized that both of the methods used here are approximate.

The fundamental assumption used in both approaches is that a portion of the wind generation variations within the hour will be addressed through dispatch in the sub-hourly energy market, and errors in the short-term wind generation forecast that go into the dispatch decisions will increase regulation requirements. A simple short-term persistence forecast was used here; in practice, more sophisticated algorithms will likely be embedded in ISO-NE automatic generation control. As the characteristics of the wind generation in actual operation are better learned through experience, the forecasting routines and other algorithms used to determine regulation needs will also improve. This will lead to an optimization over time of the amount of additional regulation scheduled and procured to deal with the increased net load variability due to wind generation.

For the remainder of this discussion, the most conservative of the previous calculations – namely the “Regulation – High Estimates” will be used.

4.4.3 Summary – Impacts of Wind Generation on ISO-NE Regulation Requirements

Based on the preceding analysis, summarized in Figure 4–9, the following conclusions regarding the impacts of wind generation on ISO-NE regulating requirements are made:

- For any of the wind generation scenarios examined, the amount of additional regulation needed to maintain control performance will vary with the current wind production level.
- The unique variability of each scenario is considered through the statistical characterization of the aggregate 10-minute data from the NEWRAM. A large number of factors influence this variability, and are beyond the scope of this analysis. However, sufficient empirical data provides a way to bypass such a complicated analysis, and instead utilize the observed or learned behavior of the aggregate wind generation for operational analysis.
- Fast fluctuations in wind generation – over tens of seconds to a minute – are relatively small due to smoothing effects and have very little impact on ISO-NE regulation requirements.

- The difference in variability between scenarios with the same energy penetration is reflected in these results. The differences in regulation impacts discernable amongst layouts at the same energy penetration levels can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenario layouts of wind generation exhibit higher variability from one ten-minute interval to the next than others. A number of factors could contribute, including the relative size of the individual plants in the scenario layout (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines comprising the scenario, as more turbines would imply more spatial diversity.
- Regulation requirement is only slightly increased at 2.5% penetration. The calculated change is likely within the "noise" of the assumptions and analytical methodology.
- At 9% penetration, the maximum hourly regulation requirement is changed by about 25%, and the average requirement over the year is about double (82 to 161 MW). With current practice for load alone, there are about 4000 hours in the years where the scheduled regulation is either 30 MW or 50 MW; at 9% wind penetration, the data shows less only 25 hours over the course of the year analyzed where the hourly regulation is 50 MW or less.
- At 14% penetration, average regulation requirements are more than doubled depending on scenario. With 20% energy penetration, average regulation could be nearly 4 times the amount currently carried by ISO-NE.
- The current practice for scheduling regulation may be impacted. Regulation quantities for specific hours and day types are determined months in advance in some cases, although the amount actually procured is determined nearer to real time. With wind generation, the amount scheduled in advance would have to be on the basis of the maximum possible wind generation variability. This would correspond most closely to the "Maximum" values shown in Table 4–3 through Table 4–5; the amount actually procured would depend on the actual wind generation level, and could be as low as the "Minimum" amounts in the same tables.
- Analysis by ISO-NE operations personnel and the analysis of historical ACE data provide evidence that even the "Low Estimate" regulation numbers shown in the tables may be conservative.

Regulation requirements at ISO-NE are continually evaluated and adjusted based on operating experience and a desire to maintain adequate control performance with economic efficiency. Consequently, regulation procured for any level of wind penetration will likely be highest initially, and then reduced over time as experience is gained. The analysis in this project was not intended to arrive at the "final numbers" that will be reached through the ISO-NE process, but rather to ascertain whether the probable increase in regulation requirements would be within the capability of the ISO-NE generating fleet.

After a review of the three estimates of increased regulation requirements, ISO-NE Staff concludes that there may be adequate supply and its business process is sufficiently robust to meet the challenges ahead.

4.5 Impacts on Other Operating Reserves

Regulation is just one piece of the ancillary services procured by ISO-NE to maintain system reliability. The impacts of wind generation as defined by the study scenarios on the other elements – 10-minute spinning reserve (TMSR), 10-minute Non-spinning Reserve (TMNSR), and 30-minute Operating Reserve (TMOR) – are examined here.

4.5.1 10-Minute Spinning Reserve (TMSR)

ISO-NE counts regulation resources toward their TMSR requirement. Conceivably, regulation could be near the top of the aggregate range when a contingency occurs, thereby actually reducing the amount of spinning reserve available for replacing lost generation. This current policy is based on years of experience. With additional regulation required by wind generation, the amount of TMSR available to respond to a contingency could be lower than the current minimum amounts.

Figure 4–11 shows the hourly profile of regulation for load, regulation for the “20% Queue + Best Sites Onshore” scenario (using the Regulation – High Estimate), and TMSR. It is apparent that the amount of TMSR available to deploy for contingencies is substantially reduced. In other words, the regulation for net load (in blue) can be as much as twice as large for load alone (in red) which decreases the capacity available for TMSR (the distance between black line and the blue or red lines, respectively). Figure 4–12 provides a closer view of four separate weeks from Figure 4–11.

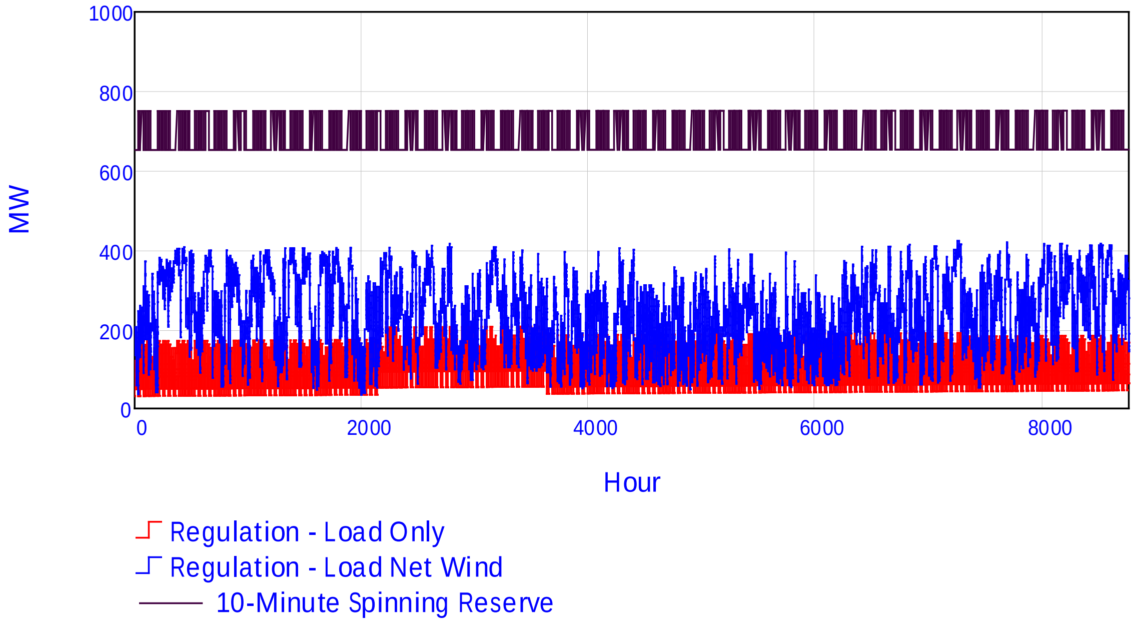


Figure 4–11 View of annual hourly regulation for load and net load for “20% Queue + Best Sites Onshore” scenario, shown with hourly TMSR

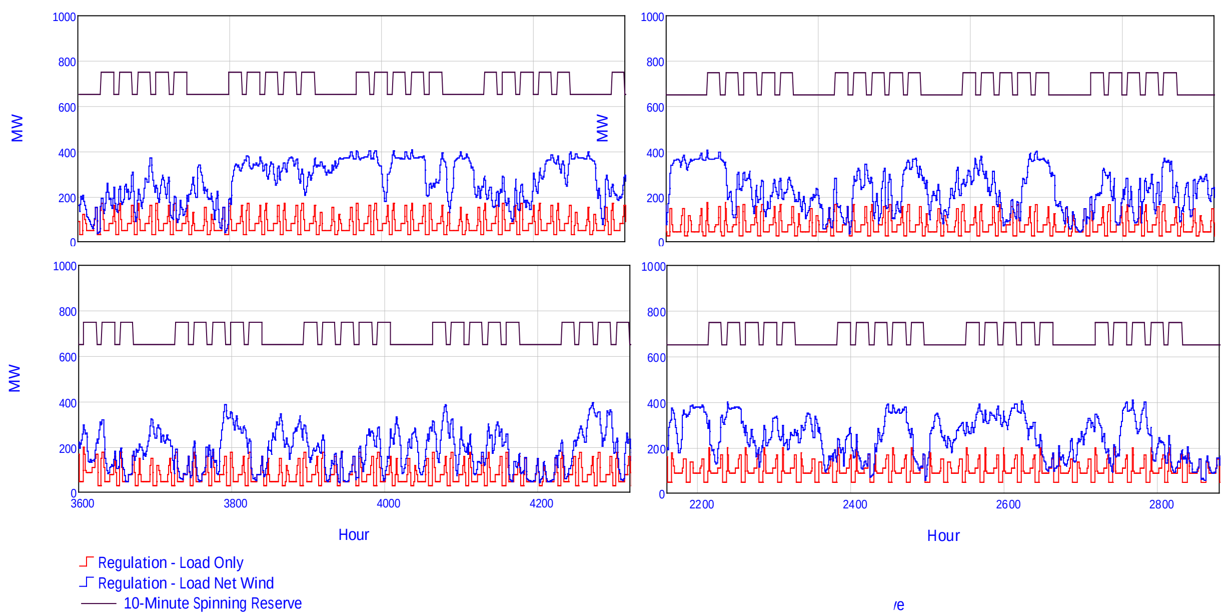


Figure 4–12 Expanded views of Figure 4–11

Figure 4–11 and Figure 4–12 show that the amount of available TMSR with load alone is never lower than 450 MW (650 TMSR – 200 MW Regulation). For this wind generation scenario, there are hours where the available TMSR is reduced to less than 250 MW. The minimum levels assume that the regulation is deployed in the upward direction to the maximum value, which would be a momentary condition until regulation is re-balanced, so this discussion focuses on a worst-case condition. Nonetheless, it could represent a vulnerability to a contingency event and would certainly merit close monitoring.

The current ISO-NE practice of counting regulation toward TMSR is based on experience. From this, it can be inferred that preserving the existing levels of available TMSR with wind generation would be consistent with current practice. To achieve this, TMSR would need to be supplemented by the incremental amount of average regulation required for wind generation. The amount of the supplement would be equal to the difference between the average regulation required for load and that required for wind generation.

Table 4–7 shows the additional TMSR required for each scenario should the policy described above be adopted. At penetrations exceeding 2.5%, TMSR would need to be increased to maintain current levels of contingency coverage with spinning reserve. These amounts range from 140 to 230 MW for the 20% scenarios, 100 to 150 MW for the 14% scenarios, and 80 MW for the 9% penetration level. Also, the table is based on the simplified modeling of operating reserves used in this study, so the actual procedure could be somewhat more complicated.

Table 4–7 Augmentation of TMSR for Incremental Wind Regulation

Scenario	Supplemental TMSR (MW)
20% Queue + Best Sites Onshore	208
20% Queue + Best Sites Offshore	231
20% Queue + Balanced Case	152
20% Queue + Best Sites by State	167
20% Queue + Best Sites Maritimes	139
14% Queue + Best Sites Onshore	146
14% Queue + Best Sites Offshore	135
14% Queue + Balanced Case	117
14% Queue + Best Sites by State	123
14% Queue + Best Sites Maritimes	104
9% Full Queue	79
2.5% Partial Queue	20

4.5.2 Thirty Minute Operating Reserve (TMOR)

The portions of ISO-NE operating reserves not performing regulation duty are held to cover major loss-of-supply contingencies, errors in forecasted load, loss of transmission elements, and to restore reserves upon the aforementioned events. Available spinning reserves respond immediately through inertial and governor action. To restore frequency, spinning reserves are dispatched upward and non-spinning reserves are started to both assist and replace spinning reserves. Over time, 30-minute reserves replace both types of 10-minute reserves that are now serving load along with the lost generation that created the contingency.

The regulation analysis above (Section 4.4) considers the real-time variability of wind generation and represents additional capacity needed to compensate for this variability, and shows how regulation capacity would need to increase for the wind generation scenarios considered in the study. The remaining questions are concerned with the impacts on other reserve categories.

Large changes in wind generation are of a markedly different nature than contingency events because:

- They do not occur instantaneously, but rather over longer periods of several tens of minutes to an hour or more;
- They are potentially predictable through advanced forecasting, which would provide operators with forewarning and time to adjust the operating plan in a somewhat economic manner.

The forecasting aspect is difficult to consider analytically since short-term forecasting, especially for significant wind events is relatively new and the performance that may be achievable is just speculative at this point in time. It therefore is not factored into the following analysis.

Using the “20% Best Sites Onshore” scenario as an example, changes in load and net load over periods ranging from one to four hours were analyzed. The distribution of hourly changes for over 26,000 hours in the three-year record is shown in Figure 4–13. Figure 4–14 provides and expanded view of the right-hand portion of the distribution, where the net change is in the positive (increasing net load) direction.

The working assumption is that the ISO-NE system is capable of responding to the largest hourly increases in load, but beyond that, operating reserves would be needed to meet the net load increase. The significance of the figures is that there are only 28 events where the hourly increase in load net of wind generation exceeds 3300 MW, which is the highest load-only change over the 26,000 hours of data. Since the 20% Best Sites Onshore is one of the most variable (Figure 4–7, highest standard deviation of 10-minute changes), it appears that the 30-minute operating reserve for load alone would be adequate to cover any changes in net load, assuming that it could be deployed on average about 10 times per year. In discussions during project meetings, it was recognized that maintaining enough additional reserve such that current levels of TMOR would never be deployed for large changes in wind was likely uneconomic. At the same time, TMOR is intended for contingency events, which at this time do not include large declines in wind generation over periods of 30 minutes to an hour or more. Based on current operating practice, it was thought that invoking TMOR once per month or less for wind generation reductions was a reasonable middle ground for purposes of this study.

TMOR would only be used if there were no other resources available to compensate for the reduction in wind generation.

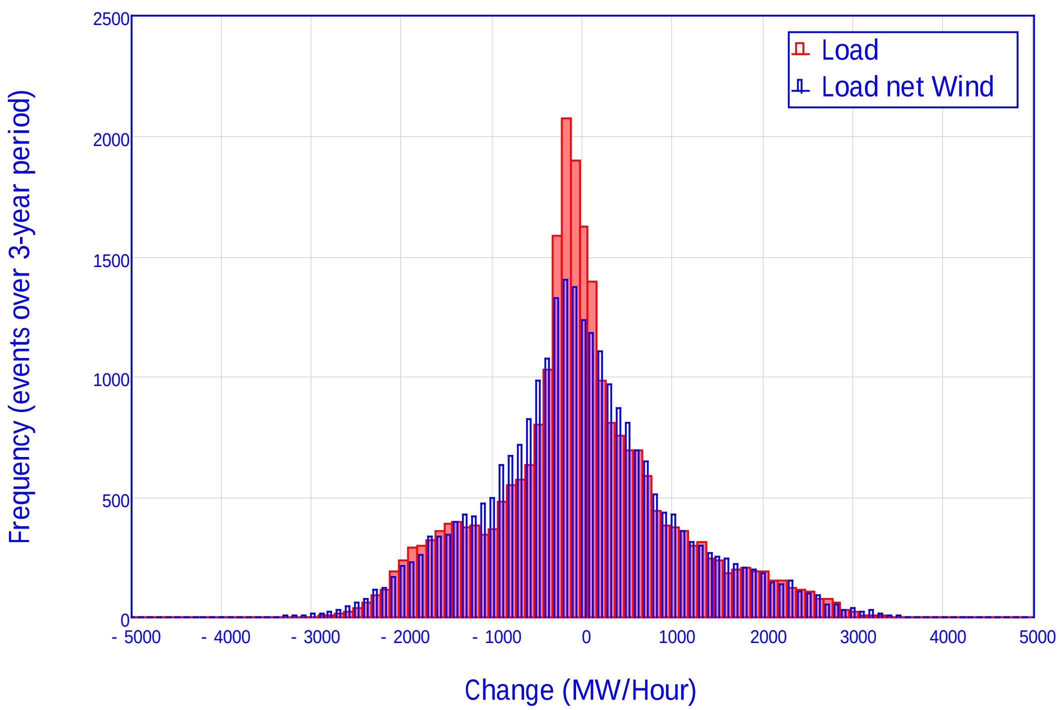


Figure 4–13 Hour changes in load and net load for 20% Best Sites Onshore scenario

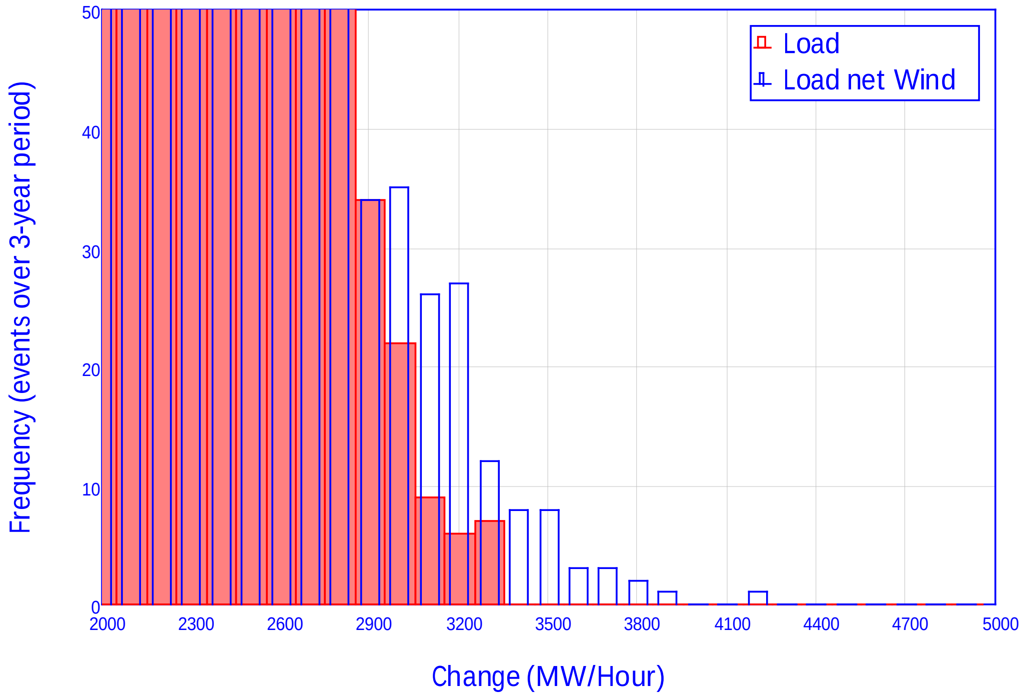


Figure 4–14 Expanded view of Figure 4–13

4.5.3 Ten-Minute Non-Spinning Reserve (TMNSR)

Changes in wind generation over an hour are used as an initial metric for assessing impacts on TMNSR. Figure 4–15 shows the standard deviation of the hourly changes as a function of production level for the wind scenario used in this example. The data can also be interpreted as the expected error in a 1-hour persistence forecast.

Short-term forecast errors, in this case the projection of wind energy delivered in the next hour, must be addressed with some type of conventional capacity. The types of capacity available in the hour include:

- Regulation
- Capacity participating in the sub-hourly energy market
- TMSR
- TMNSR
- Some TMOR

As described above, TMSR resources (as augmented for wind generation in consideration of the additional regulation capacity needed for real-time variability) would not be used to make up for under-delivery of wind energy. Regulation capacity could be used initially, but must be replaced by other resources to maintain headroom. Resources in the sub-hourly energy market would have some capability to be dispatched up to make up for a portion of the lower-than-forecast wind generation, but may be inadequate to replace it all.

For very large hourly changes (hourly persistence forecast errors) resulting in under-delivery of wind energy, non-spinning reserves may need to be deployed to either off-load regulating resources or supplement capacity in the sub-hourly market. Closer inspection of the data behind Figure 4–16 reveals that wind generation in the 20% Best Sites Onshore scenario could be expected to drop more than 1500 MW over an hour about 0.3% of the hours, or about 25 times per year. For very large hourly changes (hourly persistence forecast errors) resulting in under-delivery of wind energy, non-spinning reserves may need to be deployed to either rebalance regulating resources or supplement capacity in the sub-hourly market. Expected 1-hour persistence forecast errors for the 20% Best Sites Onshore scenario are shown in Figure 4–16.

The standard deviations of the expected hourly changes for this scenario are shown in Figure 4–15. Figure 4–16 shows the range of hourly changes for the 20% Best Sites Onshore scenario as a function of current hourly production. The diamond symbols are the standard deviation of the expected hourly change, and the ends of the vertical lines represent the largest single hourly changes observed in the three years of data. The maximum drop is 2100 MW (occurring when hourly production is between 60% and 70% of aggregate nameplate capacity) in the three years of data available for analysis. As assumed for this study, TMNSR is either 650 or 750 MW depending on the hour. Inspection of the hourly load changes shows that, for all hours, the standard deviation of the expected change is about 1000 MW, with a maximum load increase of 3300 MW occurring on 7 occasions over the three-year hourly load sample. However, if wind generation were to decrease by a large amount during a period where load was anticipated to be flat and there was a minimum amount of flexible, dispatchable capacity available, the ability of the sub-hourly market resources to make up for the deficit could be limited. In such a period, TMNSR would need to be deployed but could compensate for only part of the deficit by current practice.

The varying volatility of wind generation with production level and the low correlation to load cycles makes direct augmentation of TMNSR difficult. A different mechanism for securing additional 10-minute non-spinning reserves which recognizes the probability of a large reduction in wind generation and the ability of market resources to compensate may be a better solution (e.g. new ERCOT 15-minute market product). Since the reductions in wind generation under consideration here happen over an hour or substantial fraction thereof and may be predictable, it is also not clear that the 10-minute capability would be necessary; some combination of 10-minute and 30-minute reserves could provide the range required over time to meet the decline in wind energy delivery.

In addition, there would almost always be some flexibility to be drawn from sub-hourly energy market resources. The large changes in wind generation under consideration here happen over an hour, or several consecutive sub-hourly market clearing intervals. Even a simple persistence forecast would capture a portion of this large wind ramp, albeit with some time lag, and feed it into the calculation of the sub-hourly market clearing, thereby extracting upward movement from energy market resources.

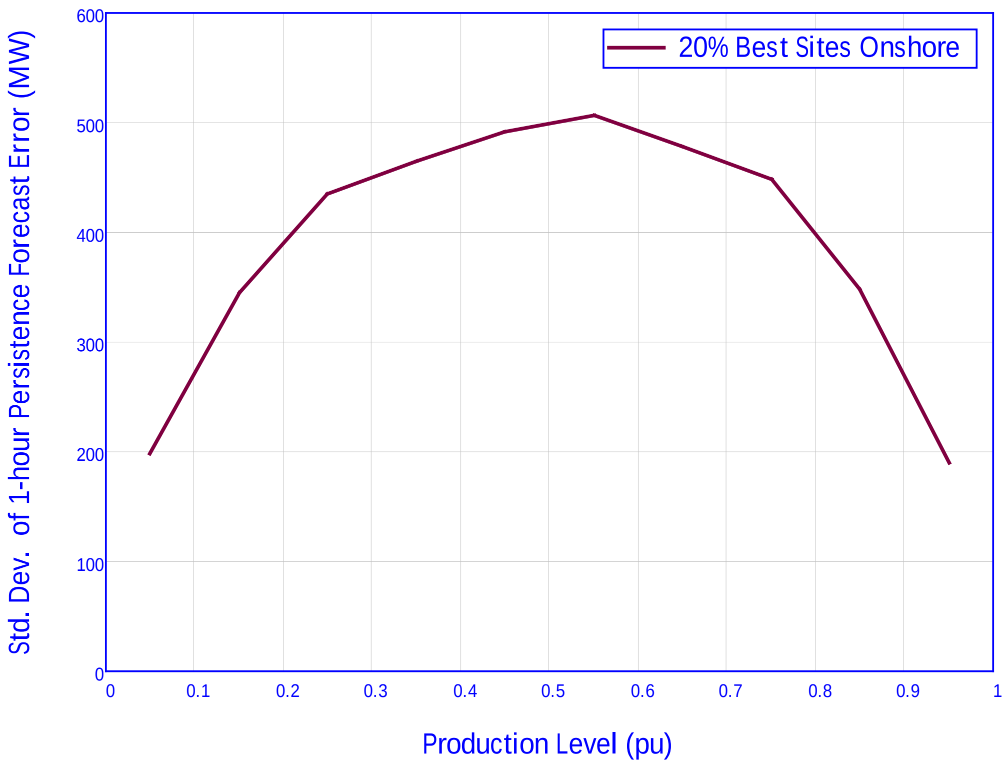


Figure 4–15 1-hour persistence forecast error for 20% Best Sites Onshore scenario

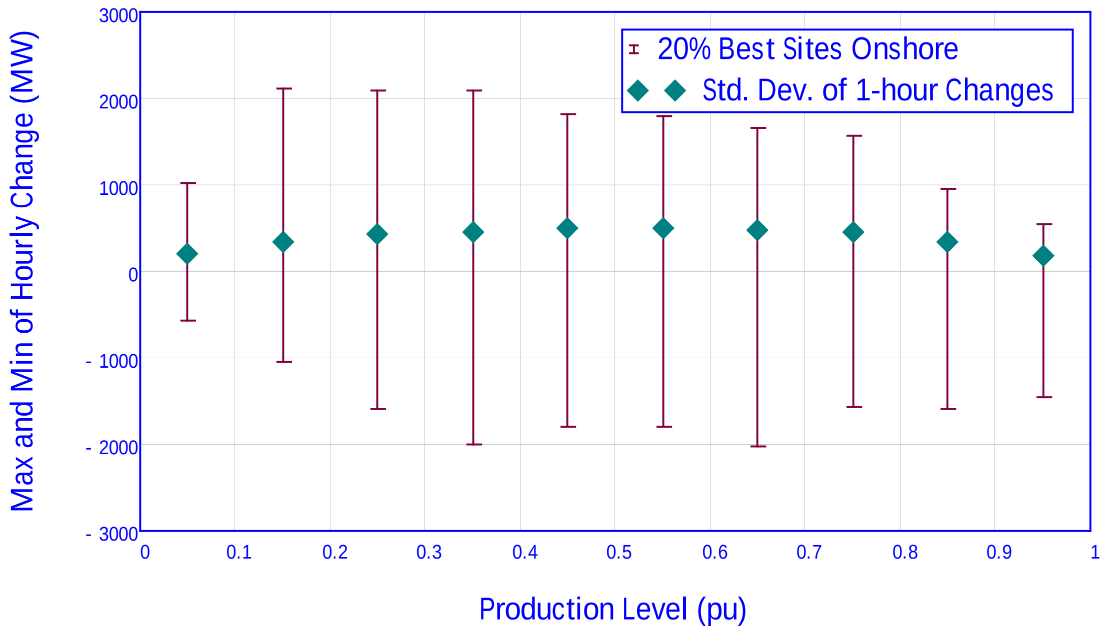


Figure 4–16 Maximum and minimum hourly wind generation changes from three-years of “20% Queue + Best Sites Onshore” scenario data

The GE MAPS production simulations provide guidance regarding the within-hour flexibility, as it tracks a range of information about generation in each hour of simulation. In addition, the production simulations have directly “seen” the hour-to-hour changes in net load, and deployed generation to meet those changes within the range and ramp limits of each individual unit.

A thorough examination of MAPS results for the 20% Best Sites Onshore case for 2006 load and wind patterns was conducted. State-of-the-art day-ahead wind generation forecasting was utilized in the unit commitment for this case. The objectives were to use the simulations to confirm some of the statistical analysis presented here, as well as to shed additional light on the in-hour flexibility that resulted from commitment and dispatch of the ISO-NE fleet.

The summarized hourly production simulation results in MAPS quantified the commitment status and dispatch of all units by technology and fuel type, and also reported the status of the aggregate constraints. Included here for each generator type were:

- Maximum and minimum generation – defines the highest and lowest possible dispatch levels for the generation online each hour. Maximum generation is taken as the total committed generation for the hour; minimum aggregate generation level is reported directly by MAPS from operating data on individual committed units.

- Range-up - the difference between the hourly dispatch point and the maximum possible dispatch, for each hour
- Range-down, as above, for each hour
- Ramp rates, both down and up, reported in MW/min, at the start of each hour

Chronological ISO-NE load and scenario wind data at 10-minute resolution was examined to determine the maximum range up and down from the average hourly value for net load. The maximum ramp rates, up and down, were also computed as the largest change net load from one ten-minute interval to the next within each hour.

The highest range and ramp values for each hour computed from the 10-minute data were then compared to the production simulation results. The hourly flexibility in terms of range was first adjusted by subtracting out the specified TMSR for the hour (either 650 MW or 750 MW per the assumptions used in the study), as this generation is necessary to provide regulation and cover contingency events. The number of hours where the maximum range of net load, up or down, exceeded the hourly range flexibility was counted. A similar process was used for ramp rate, although the ramp rates reported by MAPS were used without adjustment for units that would be on regulation duty. Results for the 20% Best Sites Onshore case are shown in Table 4–8.

Table 4–8 Results from analysis of MAPS data for 20% Best Sites Onshore scenario

	# of Hours where requirement exceeded capability			
Case	Range UP	Range Down	Ramp UP	Ramp DN
20% Best Sites Onshore	191	55	3	205

The table shows that in 191 out of 8784 hours in the production simulation, the available range up (adjusted to remove the TMSR) was not adequate to cover the highest deviation of 10-minute load-net-wind generation from the hourly average. There are two implications of this deficiency:

- Spinning reserves held for regulation and contingency would be dispatched, thereby reducing the available TMSR; demand response with sufficient response capability could count toward this requirement
- Quick-start units would be deployed to provide additional flexibility and replace TMSR that was being dispatched, possibly reducing TMNSR below criteria.

The Range Down violations could be addressed by wind generation curtailment, as discussed in the Task 2 report for this study. Ramp Down violations result from either a large decrease in load or sudden increase in wind generation. For wind, ramp-rate control would be a possible solution (Task 2 report). There were only 3 violations of the Ramp UP capability, which is likely within the “noise” of the assumptions and process used here.

To better calibrate the analysis, the same procedure was applied to a “No Wind” case. It was found that the flexibility limitations were exceeded in some hours here as well. The effect of wind generation is then taken to be the difference between the cases with and without wind generation. These results are shown in Table 4–9.

The existence of apparent violations in the “No Wind” case is a reflection of “extending” the resolution of the hourly chronological production simulations to view intra-hour phenomena. The production simulations enforce unit constraints on an hourly basis; in effect, it is assumed that the load or net load is moving smoothly from one hourly value to the next. The preceding analysis fills in detail by comparing hourly values – Range Up, Range Down, etc. – to higher resolution data at ten-minute time steps. Consequently, the analysis is far from exact; the results of this analysis, however, are still considered useful and revealing, in that the flexibility of the system each hour is compared to requirements ascertained from closer examination of changes within each hour.

Table 4–9 Comparison of MAPS analysis results for 20% Best Sites Onshore and No Wind cases

	# of Hours where requirement exceeded capability			
Case	Range UP	Range Down	Ramp UP	Ramp DN
20% Best Sites Onshore	191	55	3	205
No Wind	100	39	3	193
Difference	91	16	0	13

The differences between the cases show very little impact of wind generation on flexibility except for the Range UP criteria. Additional generation would need to be quickly deployed about 7 or 8 times per month (91/12) to replenish TMSR and rebalance the reserves. This assumes that the quick-start capacity to cover wind declines or load increases would be drawn from the TMNSR.

The question of whether TMNSR should be augmented comes down to the criteria for using it. Figure 4–17 provides a view of the frequency and magnitude of the “Range Up” deficiencies for the 20% Best Sites Onshore and No Wind cases. Using the No Wind case as a baseline, it is first assumed – somewhat arbitrarily, but drawn from discussions during Technical Review

Committee meetings with ISO-NE staff - that for purposes of this evaluation assume that TMNSR can be called on up to 10 times in a year to compensate for large load increases or wind generation decreases. So, to limit TMNSR deployment to this number for the case with wind, the chart indicates that an additional 300 MW of non-spinning reserve, beyond that defined as TMNSR, would need to be available (300 MW is the approximate difference along the horizontal axis between the No Wind case and the With Wind case at 10 events/year).

This is only a rough approximation, since the results of this analysis show that for load alone, there are 100 hours in the annual simulation where the available range up flexibility was insufficient. The “allowable events/year” actually comes from current ISO-NE practice, where TMNSR is occasionally deployed for large increases in load. However, there is some disconnect between the production simulations here and reality, as 100 times per year is far higher than experience shows. That is why the difference between the cases is used as the metric.

It should also be noted that this additional quick-start generation would be needed only when indicated by wind generation conditions – if wind generation production were very low or predicted to be very low, there would obviously be no concern. And, the production simulations show no hours where the available quick-start generation (beyond the amount designated as TMNSR) would be less than the capacity required to supplement the aggregate range up sufficiently to cover the load-net-wind generation change.

Because sufficient quick-start generation appears to be available at all hours, there would always be adequate capacity to meet the TMNSR requirement as well as supplementing flexibility to meet large short-term changes in wind generation. The question actually appears to be one of semantics, but in reality it likely comes down to the market mechanisms required to ensure both adequate TMNSR as presently defined and additional non-spinning reserve to cover very large wind reductions when conditions warrant (i.e. there would be no need to designate additional TMNSR if wind production levels are low or within the capability of the sub-hourly market resources).

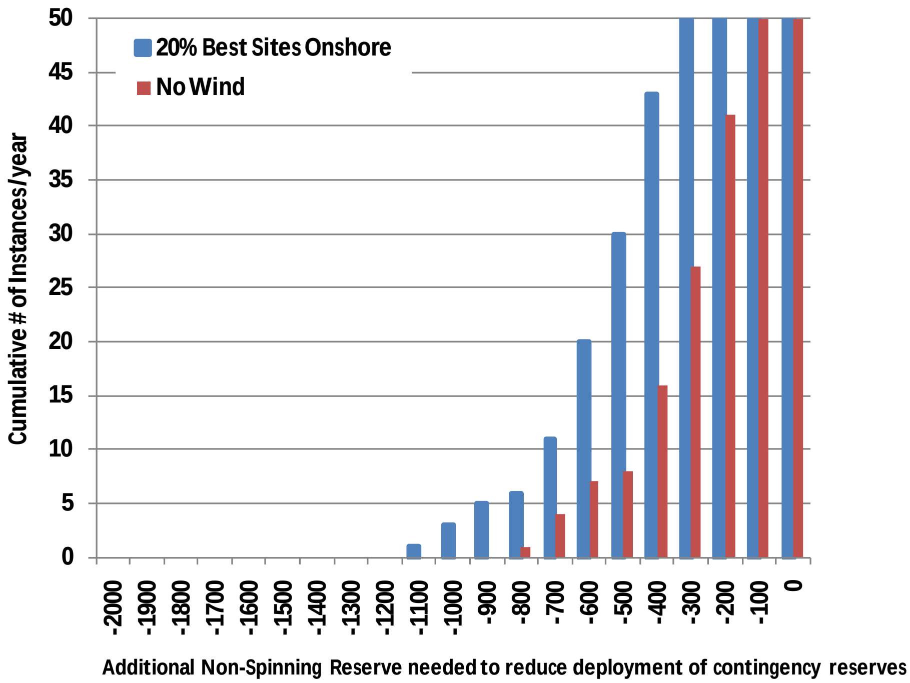


Figure 4–17 Additional non-spinning reserved needed for large wind changes to maintain TMSR at criteria for contingencies – 20% Best Sites Onshore case

A similar analysis was conducted for the 9% penetration case. Results are shown in Table 4–10. The number of times that Range Up capability within the hour was insufficient is lower than observed in the 20% case.

The “Range Up” violations are of primary interest for comparison to the 20% case analyzed previously. The reduction in the number of “Ramp Dn” violations is curious, however. Time limitations prevented a detailed examination; however, as explained earlier, these would be associated with large increases in wind generation. If real, rather than an artifact of the approximate nature of this analysis combined with coincidence, the issue would not be one of ISO-NE fleet limitations and is addressable by the ramp rate (up) limits as described in the Task 2 report.

Table 4–10 Comparison of MAPS analysis results for 9% Energy Queue and No Wind cases

	# of Hours where requirement exceeded capability			
Case	Range UP	Range Down	Ramp UP	Ramp DN
9% Energy Queue	136	0	3	8
No Wind	100	39	3	193
Difference	36	-	0	-

As expected, the additional non-spinning reserve needed to reduce the events/year (beyond the No Wind case) to 10 is smaller than for the 20% case. From Figure 4–18, the difference between the wind and no wind cases at 10 events per year is about 100 to 150 MW.

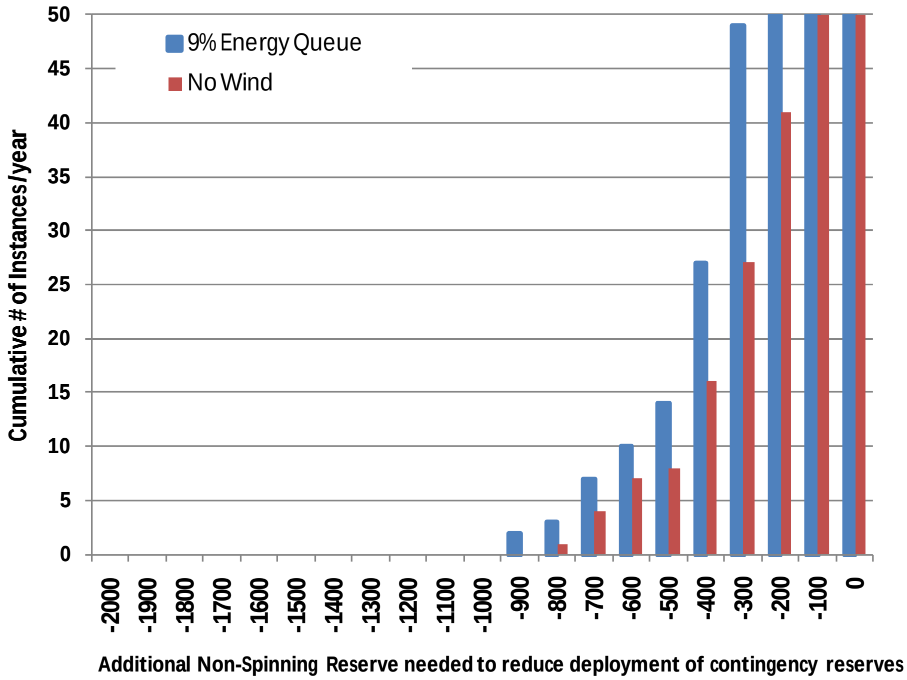


Figure 4–18 Additional non-spinning reserved needed for large wind changes to maintain TMSR at criteria for contingencies – 9% Energy Queue case

Two data points for operating reserve impacts of wind generation have been developed through approximate, but detailed, examination of the MAPS production simulation results. Taking into account the intra-hour flexibility of the ISO-NE fleet reported from the chronological hourly production simulation results, some additional operating reserve, primarily in the form of 10-minute non-spinning reserve is indicated for the 20% scenario analyzed. A smaller amount is needed at the 9% penetration level.

It should also be noted that the available quick-start capacity in the cases above far exceeded in every hour what would have necessary to remedy the reported violations. Availability in the production simulations indicates only that the fleet possesses the required capacity resources; some mechanism would need to be established to ensure access.

Due to the approximate nature of this analysis, results for other penetration levels and variants of the penetration levels analyzed here are drawn from an extrapolation of these results. Detailed analysis of alternate scenarios at 20%, for example, may produce slightly different numbers than the case described here. However, it would be difficult to discern whether the differences are actually a result of the scenario characteristics or fall within the “noise” of the approximate calculation.

Table 4–11 shows the results of this analysis as applied to all scenarios. The additional TMNSR, which as described above might be implemented as a new market product, would only be procured when indicated by wind generation conditions. Given the likely lead times, they would be based on forecast of wind generation, either a day or some hours ahead. In addition, the need for additional TMNSR would also be a function of system conditions, namely the amount of intra-hour maneuverability in the sub-hourly market.

And, as mentioned above but worth mentioning again, the production results show this additional quick start capability to be available all hours of the year.

Table 4–11 Additional TMNSR from Detailed Analysis of Production Simulations and 10-minute Data

Energy Penetration Level	*Additional TMNSR
20% - All scenarios	300 MW
14% - All scenarios	**225 MW
9%	150 MW
2.5%	**0 MW

* carried only during hours of high wind production

**extrapolated

4.6 Observations and Conclusions

Conclusions regarding wind generation impacts on ISO-NE operating reserves along with other observations and recommendations are described here.

4.6.1 Regulation

Significant penetration of wind generation will increase the regulation capacity requirement and will increase the frequency of utilization of these resources. The study identified a need for an increase in the regulation requirement even in the lowest wind penetration scenario (2.5% wind energy), and the requirement would have noticeable increases for higher penetration levels. For example, the average regulation requirement for the load only (i.e., no wind) case was 82 MW. This requirement increases to 161 MW in the 9% wind energy scenario—and to as high as 313 MW in the 20% scenario.

The primary driver for increased regulation requirements due to wind power is the error in short-term wind power forecasting. The economic dispatch process is not equipped to adjust fast enough for the errors inherent in short-term wind forecasting and this error must be balanced by regulating resources. (This error must be accounted for in addition to the load forecasting error.)

There are some differences in regulation impacts discernable amongst scenarios at the same energy penetration levels. This can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenarios of wind generation exhibit higher variability from one ten-minute interval to the next than others. A number of factors could contribute, including the relative size of the individual plants in the scenario (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines and wind plants comprising the scenario, as more turbines and more wind plants would imply more spatial diversity.

At the same time, however, the differences may be within the margin of uncertainty inherent in the analytical methodologies for calculating regulation impacts. Given these uncertainties, it is difficult to draw concrete conclusions regarding the relative merits of one scenario over the others from the regulation viewpoint. For example, future developments in short-term wind generation forecasting could result in a more variable, but easier to forecast, deployment of wind generation a smaller burden on regulation, since a large proportion of the changes would be scheduled into the sub-hourly energy market.

ISO-NE routinely analyzes regulation requirements and makes adjustments. As wind generation is developed in the market footprint, similar analysis will take control performance objectives and the characteristics of the operating wind generation through empirical data into account. At a minimum, high-resolution data for all wind generation facilities should be collected and archived. When regulation needs are analyzed, approaches like those illustrated in this report or others developed by ISO-NE staff can be used to augment the current methods for evaluation regulation requirements.

Analysis of these results indicates, assuming no attrition of resources capable of providing regulation capacity, that there may be adequate supply to match the increased regulation requirements under the wind integration scenarios considered. ISO-NE’s business process is robust and is designed to assure regulation adequacy as the required amount of regulation develops over time and the needs of the system change.

4.6.2 Other Operating Reserves

Additional operating reserves will likely be required as wind penetration grows. The analysis indicates that TMSR would need to be supplemented as penetration grows to maintain current levels of contingency response. Increasing TMSR by the average amount of additional regulation required for wind generation would insure that the spinning reserve are available for contingencies would be consistent with current practice.

Using this approach, TMSR would be increased by 300 MW or so for the 20% scenarios, up to 150 MW for 14% energy penetration, and about 80 MW for 9% penetration.

The amount of additional non-spinning reserve that would be needed under conditions of limited market flexibility and volatile wind generation conditions is about 300 MW for the 20% Best Sites Onshore case, and 150 MW for the 9% Energy Queue case. This incremental amount would maintain the TMNSR designated for contingency events per existing practice, where it is occasionally deployed for load changes or large forecast errors. "Volatile wind generation conditions" would ultimately be based on ongoing monitoring and characterization of the operating wind generation. Over time, curves like those in Figure 4–7 would be developed from monitoring data and provide operators with an increasingly confident estimate of the expected amount of wind generation that could be lost over a defined interval.

In additional to the penetration level, the amount is also dependent on the following factors:

- The amount of upward movement that can be extracted from the sub-hourly energy market – the analysis indicates that additional TMNSR, or a separate market product for wind generation, would be needed on average only about 7 or 8 times per month at 20% penetration.
- The current production level of wind generation relative to the aggregate nameplate capacity.
- The number of times per period (e.g. year) that TMSR and TMOR can be deployed – for the examples here, 10 was assumed.

The additional TMNSR would be used to cover anticipated extreme changes (reductions) in wind generation. As such, it purpose and frequency of deployment are different that the current TMNSR. A separate market product that recognizes these differences may be advisable.

At 20% energy penetration, extreme changes in load net wind generation over several tens of minutes to an hour or more are only slightly larger than those seen for load alone. The data shows only 28 events over three years of hourly data where the increase in load net wind generation is greater than the maximum increase in load alone. The magnitude of these events is within the capability of the total operating reserves carried by ISO-NE according to current practice. The large hourly changes have also been evaluated directly in the production simulations, and therefore have been considered in the detailed analysis described in 4.5.3.

Due to the increases in TMSR and TMNSR, overall Total Operating Reserve (TOR) increases in all wind energy scenarios. For the 2.5% wind energy scenario, the average required TOR increases from 2,250 MW to 2,270 MW as compared to the no wind energy scenario baseline. The average required TOR increases to approximately 2,600 MW with 14% wind penetration and about 2,750 MW with 20% penetration.

The need for additional reserves varies as a function of wind generation. Therefore, it would be advantageous to have a process for scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind generation. It may be inefficient to schedule additional reserves using the existing “schedule” approach, by hour of day and season of year, since that may result in carrying excessive reserves for most hours of the year. The process for developing and implementing a day-ahead reserves scheduling process may involve considerable effort and investigation of this process was outside the scope of the NEWIS.

A summary of the estimated operating reserve impacts by scenario is found in Table 4–12.

Table 4–12 Summary of Operating Reserve Impacts for Study Wind Generation Scenarios

Scenario	Regulation (MW)	TMSR (MW)	TMNSR (MW)	TMOR (MW)	Ave. TOR (MW)
Load Only	82	750	750	750	2250
20% Queue + Best Sites Onshore	290	958	1050	750	2758
20% Queue + Best Sites Offshore	313	981	1050	750	2781
20% Queue + Balanced Case	234	902	1050	750	2702
20% Queue + Best Sites by State	249	917	1050	750	2717
20% Queue + Best Sites Maritimes	221	889	1050	750	2689
14% Queue + Best Sites Onshore	228	896	975	750	2621
14% Queue + Best Sites Offshore	217	885	975	750	2610
14% Queue + Balanced Case	199	867	975	750	2592
14% Queue + Best Sites by State	204	873	975	750	2598
14% Queue + Best Sites Maritimes	186	854	975	750	2579
9% Full Queue	161	829	900	750	2479
2.5% Partial Queue	102	770	750	750	2270

5 Operational Analysis

The purpose of the operational analysis is to evaluate the operational feasibility of integrating large amounts of variable renewable generation into the study area footprint. A range of renewable penetrations was considered as well as various system sensitivities such as fuel prices, Carbon price impacts, and transmission expansion. The analysis was performed using the GE Multi Area Production Simulation program, MAPS, which performs a day-ahead unit commitment and an hourly dispatch recognizing transmission constraints within the system and individual unit operating characteristics. Details of the model are included in Appendix C. Except where noted, day-ahead wind power forecasts were used in the commitment process. As a by-product of the analysis, the production cost and emission impact of wind power was also determined. While that information is useful and of interest to many, it is important to recognize that it is not the intent of this study to economically justify wind generation. This study seeks to determine the overall feasibility of incorporating large amounts of wind generation into the operation of ISO-NE, what operational challenges might arise, and what changes might be required to facilitate this integration.

5.1 Assumptions

The operational analysis for NEWIS was simulated for a year to approximate the year 2020. The underlying NEWIS base database, which includes ISO New England, New York ISO, PJM Mid-Atlantic and the Maritimes were modeled in detail based on sources from 2009 CELT report for ISO New England and Velocity Suite of Ventyx Vintage 2009 for the rest. Figure 5–1 below outlines the system modeled.

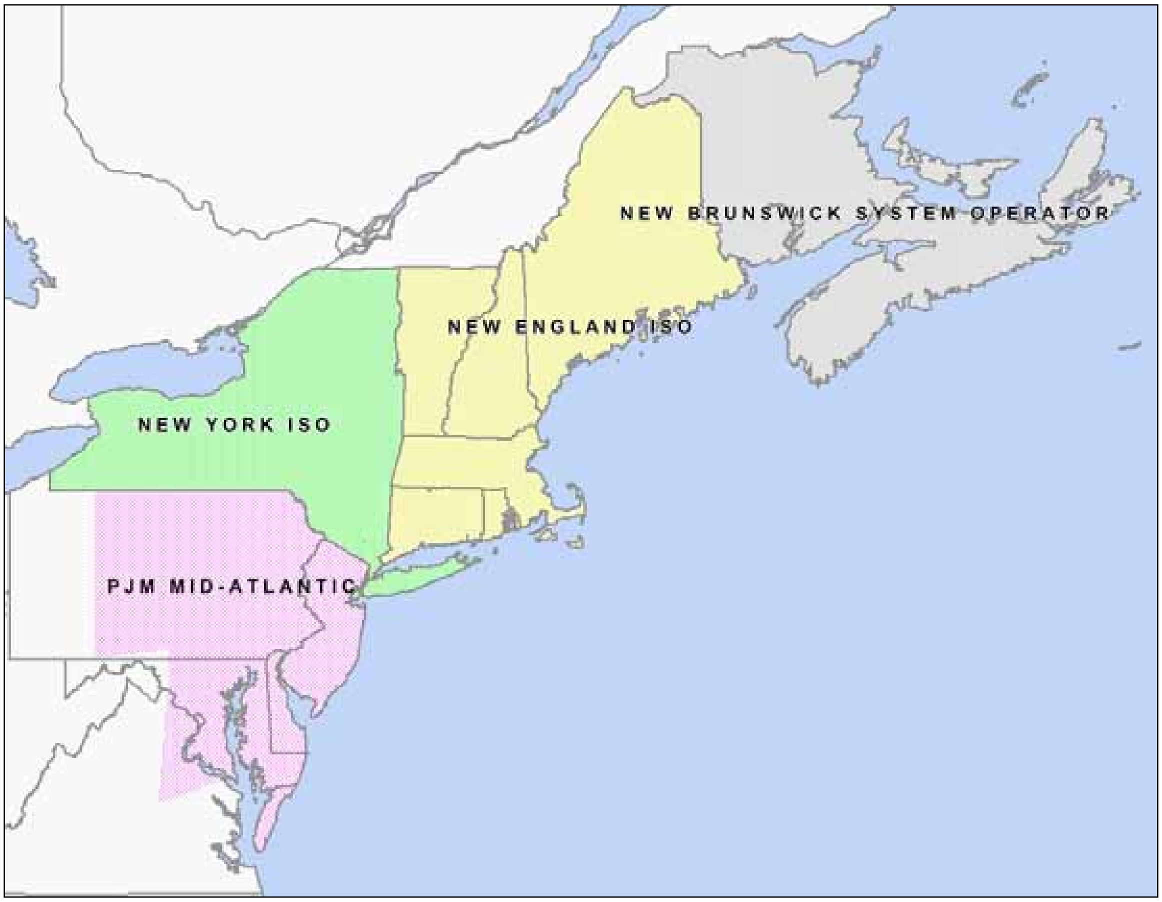


Figure 5–1 NEWIS System map

Transfers between HQ, Ontario, and NEWIS systems were represented as proxy generators as follows:

- HQ Phase 2 was modeled as a 1,600 MW generator with increasing heat rates
- HQ model duplicated for NYISO
- Ontario to NY is modeled as a 2000 MW generator with increasing cost block generator (Calibrated based on 2006 actual imports)

Areas modeled within the NEWIS system are entities that represent load and are based on the regions used in Ventyx's models. These load areas are derived through extensive analysis of FERC 715 data and Multiregional Modeling Working Groups (MMWGs) in the Eastern interconnect.

Load was extrapolated out to approximately 2020 by increasing the peak and keeping the same load factor of the yearly shape (2004, 2005, and 2006). Peak Forecasts for different regions are based on sources listed in Table 5–1.

Table 5–1 Peak Load Forecast and Source

Region	Peak (MW)	Source
ISO-NE	31,500	2009 CELT report
NYISO	36,137	2009 Load & Capacity Data (Gold Book)
PJM Mid-Atlantic	70,342	PJM Load Forecast Report January 2009
Maritimes	6,237	2008 NERC ES&D

The generator data includes full and part load heat rates, emission rates, minimum operating points and other operating characteristics appropriate to its technology, year built and size. Steady state incremental heat rates and emission rates were modeled. Ten-year historical monthly energies were used for the hydro generation. Additional thermal capacity was added to the existing generation to cover the load growth through 2020; expansion units for ISO-NE were based on the Forward Capacity Market results. Other regions included units under construction with status as of Jan-2010 to be installed in the near future. Additional combined cycle and peaking generation was added to maintain regional reserve margins requirements. The total additions are as follows:

- Maritimes - 1,000 MW
- NYISO – 150 MW
- PJM – 11,300 MW

The same expansion plan was used for all scenarios. As wind generation was added, no thermal capacity was removed.

The key fuel assumptions are listed in Table 5–2. They are based on EIA Annual Energy Outlook, April 2009.

Table 5–2 Regional Fuel price

Region	Coal ($/mmBtu)	Natural Gas ($/mmBtu)	Residual Oil ($/mmBtu)	Distillate Oil ($/mmBtu)
ISO-NE	2.86	7.63	15.77	21.36
NYISO	2.25	7.28	15.58	21.13
PJM Mid-Atlantic	2.10	7.40	15.82	21.07
Maritimes	2.86	7.63	15.77	21.36

Another key assumption is that no carbon cost has been assumed. Hurdle rates between ISO-NE, NYISO, PJM Mid-Atlantic and Maritimes were modeled at $10/MWh for commitment and $6/MWh for dispatch; separate hurdle rates were modeled for AC and DC systems. Hurdle rates represent transmission tariffs and market inefficiencies between control areas. Spinning reserve modeled for ISO-NE is synchronized 10 min spin, 750 MW during weekdays between 0700hrs to 2300hrs and 650 MW during weekdays between 2300hrs to 0700hrs and all hours during weekends. 10-minute spinning reserve was modeled in the analysis. It was verified that a sufficient amount of 10-minute non-spinning reserve was available in the simulation. 30-minute non-spinning reserve was not modeled. Wind units were modeled with a dispatch cost of $10/MWh so that nothing below this value would be displaced. In the production simulation results no variable cost was assumed for the wind generation. Capital costs were not included and dispatchable demand (i.e. Demand Response) units were modeled to meet load when price reaches $500/MWh or above. The outage schedule, for thermal generators, was held constant for all simulations.

5.2 Annual Operational Impacts

A variety of metrics are presented to address the question, “What happens to the operation of the system with high levels of intermittent wind generation?” Some of these metrics include annual generation displacement by type, system operating costs, utilization of pumped storage hydro, and locational marginal price impacts.

Running out of ramp down capability and curtailment are also important metrics to analyze the operational impacts of wind. Both signify minimum generation issues. Addressing minimum generation issues presumably means recommitting the system with more expensive units. For example, a coal unit may need to be turned off and gas turbines turned on to achieve the flexibility necessary.

5.2.1 Best Sites Onshore

The following section looks at the impacts of increasing wind penetration on the ISO-NE system. All results presented are for the Best Sites Onshore scenario with full transmission. “State of the art” (S-o-A) wind forecast was used. A subset of results for the other scenarios will be presented in Appendix C of the report.

Parameters that are normalized based on a MWh of ISO-NE wind generation, use the net wind generation. The net wind generation is calculated by subtracting the additional exports for each scenario, as compared to the No Wind Scenario, from the total ISO-NE wind energy. This is done to eliminate any benefit to ISO-NE from wind energy that is exported to the surrounding regions.

Figure 5–2 shows the normalized average seasonal daily output of a randomly selected onshore wind plant. Not surprisingly, the summer has the lowest nameplate output. The winter has some hours where the typical output nears 45%.

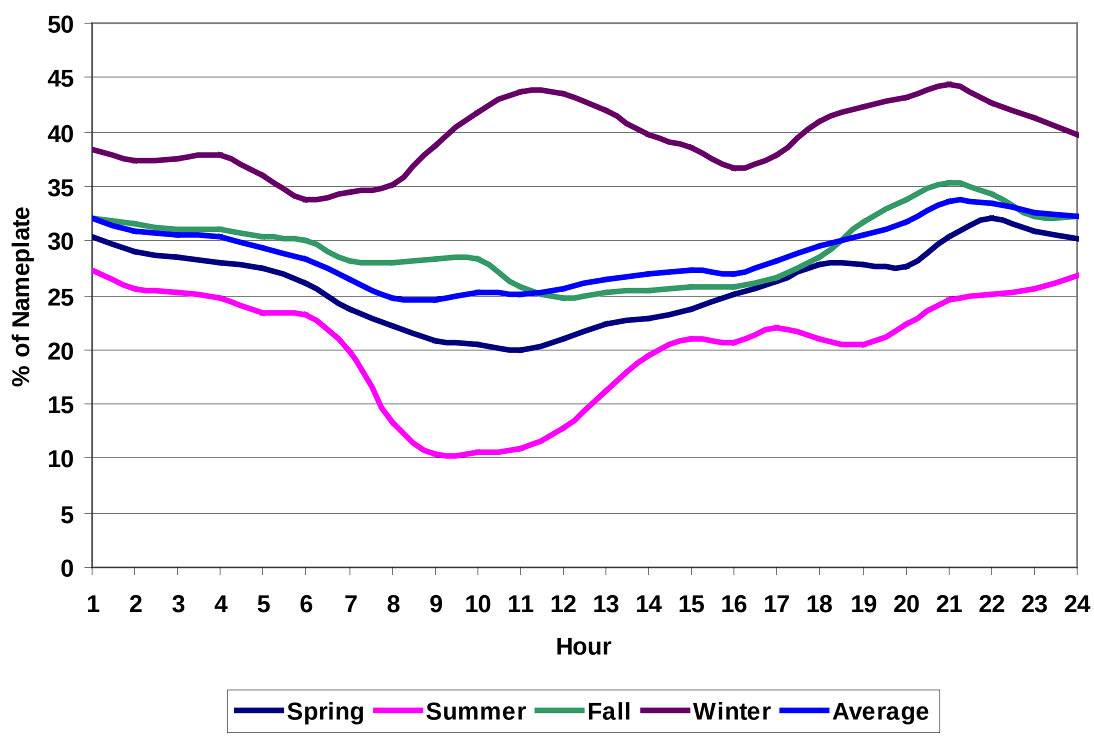


Figure 5–2 Typical seasonal average onshore plant daily pattern

Figure 5–3 shows the total generation by type for ISO-NE with increasing wind penetration. The bulk of the energy that is displaced by the wind generation as compared to the No Wind Scenario is coming from the Combined Cycle (CC) units. As the penetration increased, the steam coal (St-Coal) generation displacement increased. There are also slight variations in imports from Hydro Quebec (HQ imports) and imports/exports (Imp_Exp) from the other neighboring regions. There is an increase in imports into ISO-NE at 14% penetration. At the lower penetrations (2.5%, 9%) the surrounding regions were not built to the same penetration as ISO-NE: only existing wind was modeled. At 14% penetration, PJM and NY were built out to that penetration. With the addition of the wind they were able to export more generation to ISO-NE. This is also seen in the 20% penetration case. The Imp_Exp decreases at 24% penetration as compared to 20% penetration. The neighboring systems were kept at 20% penetration and the imports are being displaced by wind generation.

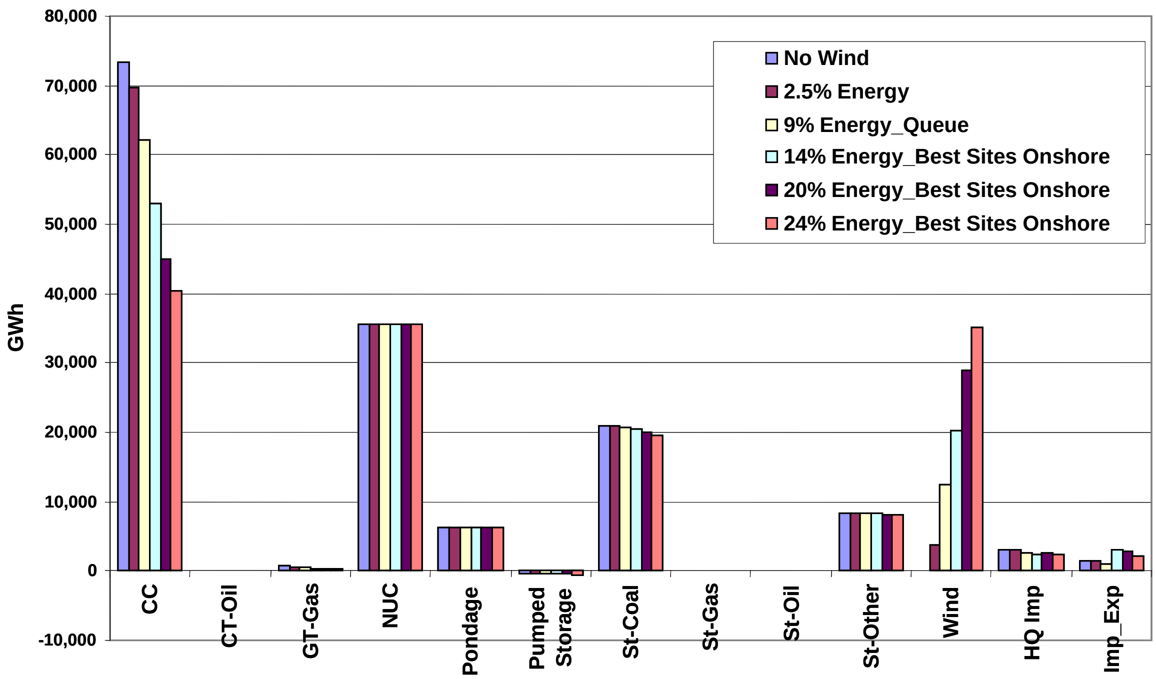


Figure 5–3 ISO-NE generation by type, S-o-A forecast, Best Sites Onshore

Figure 5–4 zooms in on the annual coal generation in Figure 5–3. At the lower penetrations, the amount of coal displacement is less than 1%. From the 14% to 24% penetration, the coal generation is reduced about 460 GWh to 1,350 GWh relative to the No Wind Scenario: a 2.2% to 6.5% reduction. Figure 5–5 shows the total ISO-NE St-Coal generation on a monthly basis. Most of the coal displacement occurs in the spring and fall months. The 24% penetration scenario has slightly more coal energy in April than the 20% case. Although this may seem counterintuitive, it is the result of the fact that the 24% penetration scenario uses the 8 GW transmission overlay, while the 20% penetration scenario uses the 4 GW transmission overlay. Although transmission is not a major issue overall, the expanded transmission in the 8 GW overlay allows more flow and hence more generation by St-Coal in April.

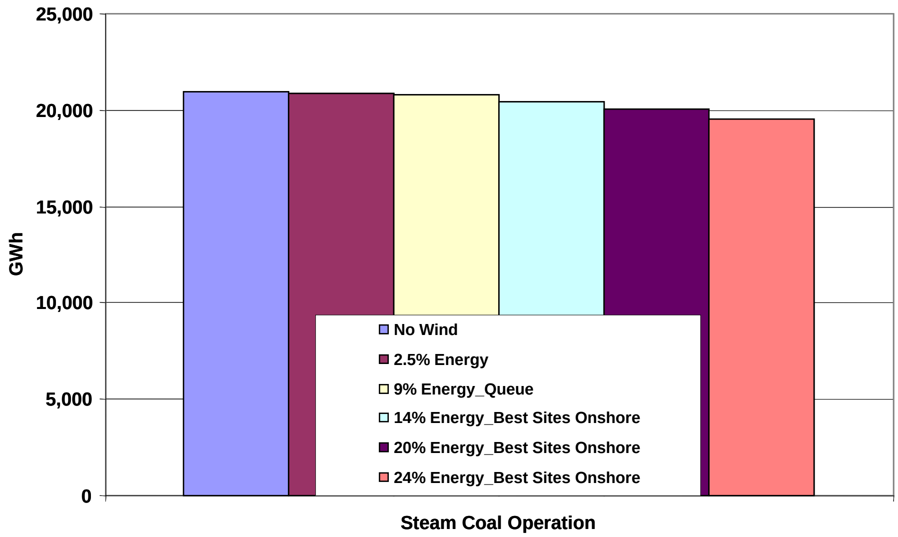


Figure 5–4 ISO-NE annual coal production S-o-A forecast, Best Sites Onshore

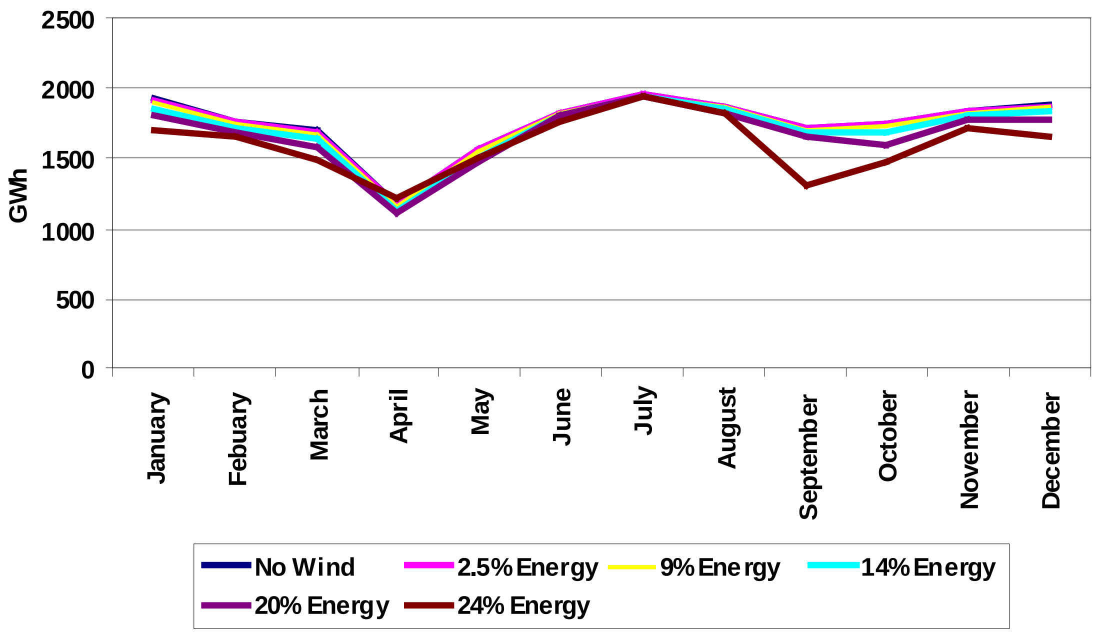


Figure 5–5 ISO-NE monthly coal production S-o-A forecast, Best Sites Onshore

As penetration of wind increases, the number of starts and energy produced by quick-start units decreases. The decline in starts is likely due to the fact that the conventional generation portfolio for this study was designed to meet ISO-NE requirements in year 2020 without wind generation. None of this conventional generation was eliminated as wind power was added to the system and therefore the quick start energy is being displaced by the wind. For example, Figure 5–6 show total number of starts the quick start units had for the increasing penetrations of the Best Sites Onshore case. The results compare using a perfect and S-o-A wind forecast. The number of starts decreases with increasing penetration using a perfect forecast. At the same time, although overall decreasing, using a S-o-A forecast, more starts occur as compared to the result with perfect forecast, due to forecast error. The delta starts between the perfect and S-o-A forecast increases with higher wind penetration. This is consistent with the analysis in section 4 where increased wind penetrations using state-of-the-art wind power forecasts cause increases in the amount of TMNSR that must be carried.

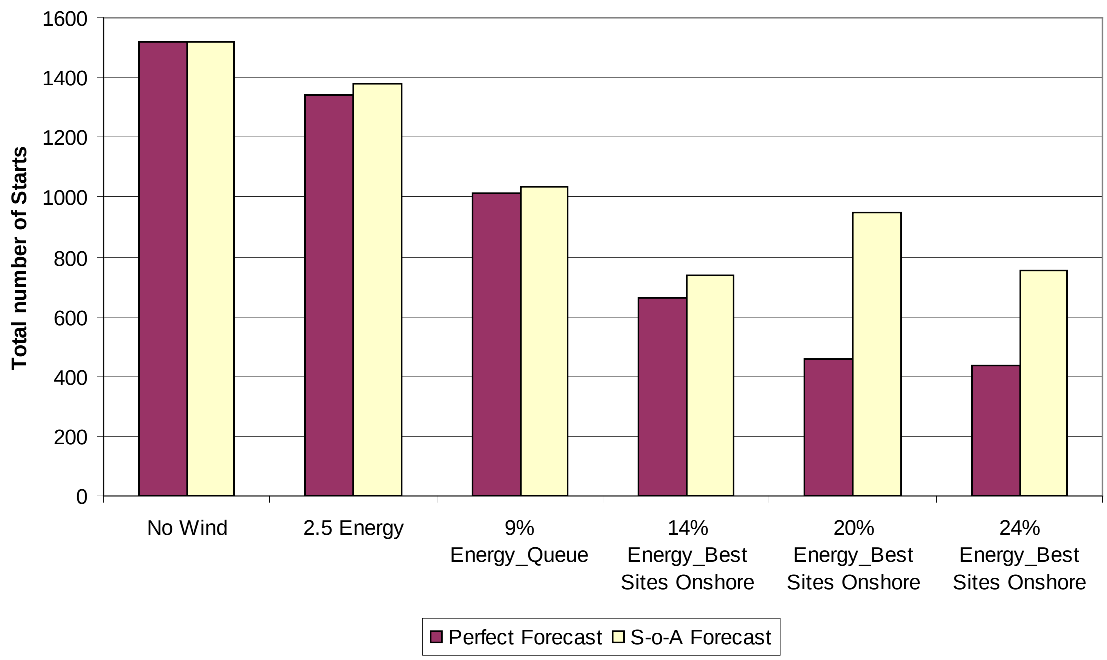


Figure 5–6 Total Annual Starts for Quick-Start Units, Best Sites Onshore, Perfect vs. S-o-A forecast

Figure 5–7 shows the hourly duration curve for the pumped storage hydro operation in ISO-NE for the No Wind and various penetration levels of wind. The operation is less for the 2.5% Energy, 9% Energy_Queue, and 14% Energy_Best Sites Onshore scenarios and increases in the 20% Energy_Best Sites Onshore and 24% Energy_Best Sites Onshore compared to the No Wind scenario. All the scenarios contain some offshore wind. Offshore typically has higher capacity factors than onshore wind and provides more energy during the peak hours. This creates less of on-peak/off-peak price differential. As the penetration increases, the overall percentage of offshore wind decreases creating more of an on-peak/off-peak price differential, therefore increasing pumped storage operation.

This is a similar result seen in the recent Western Wind and Solar Integration Study[70], the NY[71] wind integration study and the Irish All-Island report[72]. It is often believed that additional storage is necessary for large-scale wind integration. Minute-to-Minute type storage is useful to address regulation concerns, but additional large-scale economic arbitrage type storage, like Pumped storage Hydro (PSH) has been shown to not be required. As shown in these studies, as the wind power penetration increases, spot prices tend to decrease, particularly during high priced peak hours. The off-peak hours remain relatively the same. Therefore, the peak and off-peak price spread shrinks and no longer has sufficient range for economic storage operation. The price spread decreases substantially, which reduces the economic driver for energy storage due to price arbitrage. As wind penetration increases, a higher on-peak/off-peak price differential is created, therefore increasing PSH operation. Similar results will be seen later in the chapter for the 20% Energy scenario comparison.

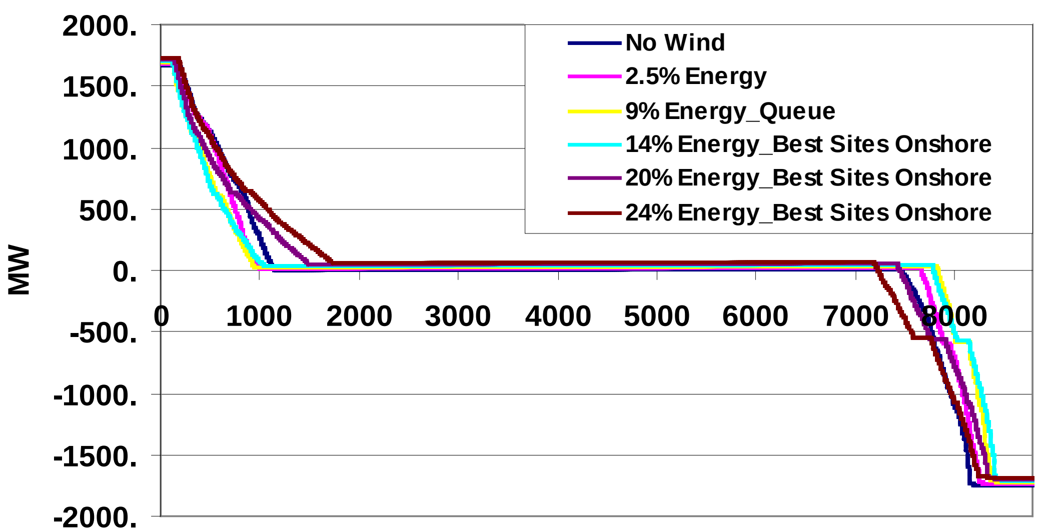


Figure 5–7 ISO-NE pumped storage operation S-o-A forecast, Best Sites Onshore

Figure 5–8 shows the reduction in total emissions as the wind penetration increases. As expected: as the wind penetration increases and conventional generation is displaced, the overall emissions go down. With 24% wind penetration, NOx is reduced by approximately

[70] http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf

[71] http://www.nyserda.org/publications/wind_integration_report.pdf

[72] http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Electricity+Grid+Study.htm

7,000 tons or 30%, SOx is reduced by approximately 8,500 tons or 8%, and CO2 is reduced by 15 million tons or 30%. As stated in the initial assumptions steady state emission rates were modeled at multiple operating levels on the generators. When transitioning from one level to another the emissions may be higher until the systems can be properly balanced. While this may cause slight temporary increases at some plants the effect should be minimal at a system level.

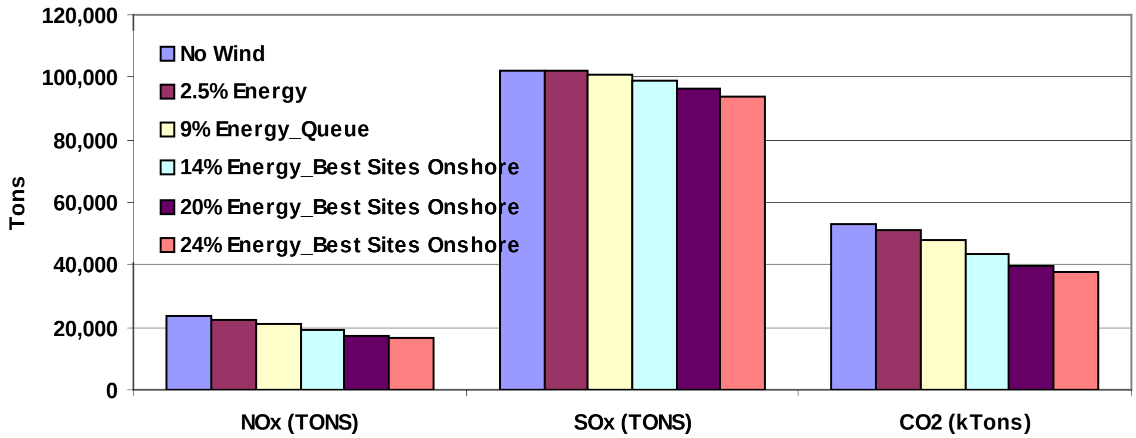


Figure 5–8 ISO-NE total emissions S-o-A forecast, Best Sites Onshore

Figure 5–9 shows the ISO-NE emission reduction per MWh of wind generation. This is calculated for each scenario by dividing total emission reduction relative to the No Wind Scenario by the total ISO-NE wind generation produced in that scenario. The net wind was used to calculate the emission reduction.

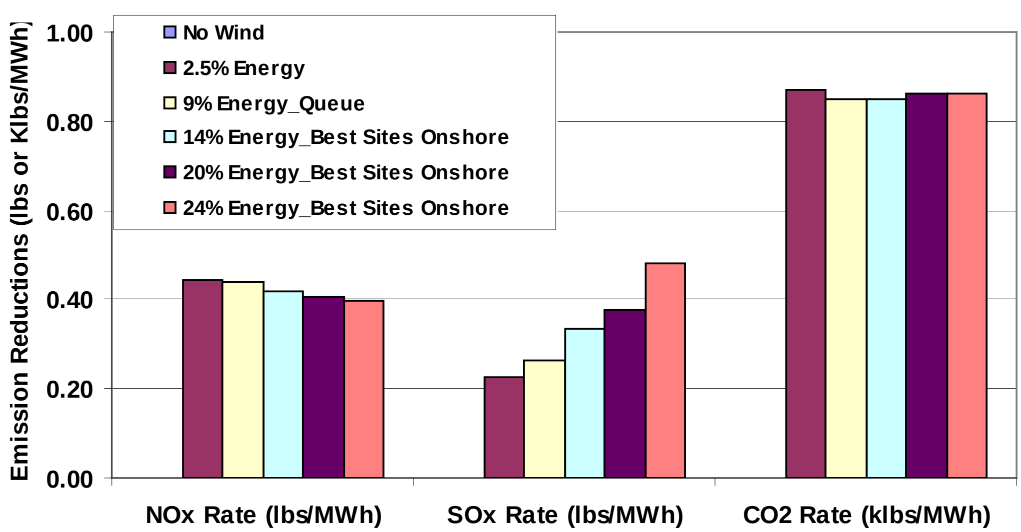


Figure 5–9 ISO-NE total emission reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

An important measure is the hourly marginal cost of energy, or spot price. In a deregulated market, like ISO-NE, this is the price paid for energy each hour. When transmission constraints are present, these values will vary across the system for any given hour, but they can be weighted by the hourly load in the constrained areas to produce an "effective" locational marginal price (LMP) for each area.

Figure 5–10 shows the annual average load weighted ISO-NE locational marginal price (LMP) for the increasing wind penetration scenarios. The average LMP for the No Wind Scenario was approximately $61/MWh. The overall reduction of LMP by introducing increasing wind penetration into ISO-NE ranged from $1/MWh at 2.5% penetration to $9/MWh at 24% penetration.

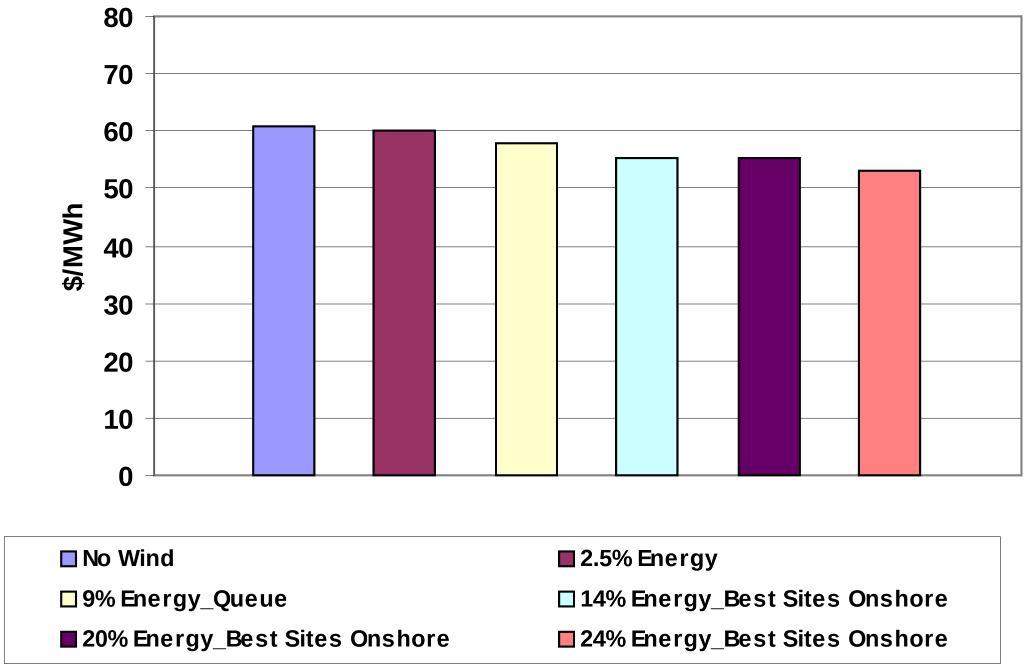


Figure 5–10 Annual load weighted average ISO-NE locational marginal price, S-O-A Forecast, Best Sites Onshore

With no renewable generation on the system, the Locational Marginal Price, or LMP, ranges from a high of approximately $350/MWh to a low of about $38/MWh, as shown in Figure 5–11. (Note: the top figure shows the LMP for the entire year. The middle figure expands the top 1000 hours and the bottom figure expands the lowest 1000 hours.) With increasing penetration of wind to the system, the highest cost is reduced to about $344/MWh with the 9%, $329/MWh with 14%, $301/MWh with 20%, and $271/MWh with 24% penetration. As can be seen on the expanded charts there is very little impact at both the high and low ends for the 2.5% and 9% penetrations. The results are more significant at the 14% penetration and beyond but that may be due to the fact that the wind generation in the neighboring systems of NYISO and PJM were also expanded at these higher levels. The lowest cost hours for the 20% and 24% scenarios drops to $10/MWh. As noted in section 5.1, the $10/MWh price is based on the wind dispatch cost. During hours when the LMP is $10/MWh, the wind was curtailed to not allow it to displace nuclear generation. This would be classified as minimum generation events. Note that although not modeled in this study, changes in market rules to allow negative energy market offers, as is currently done in NYISO and PJM, would likely result in LMPs less than zero, as wind resources would compete to stay online to earn Renewable Energy Credits (REC) or other incentives.

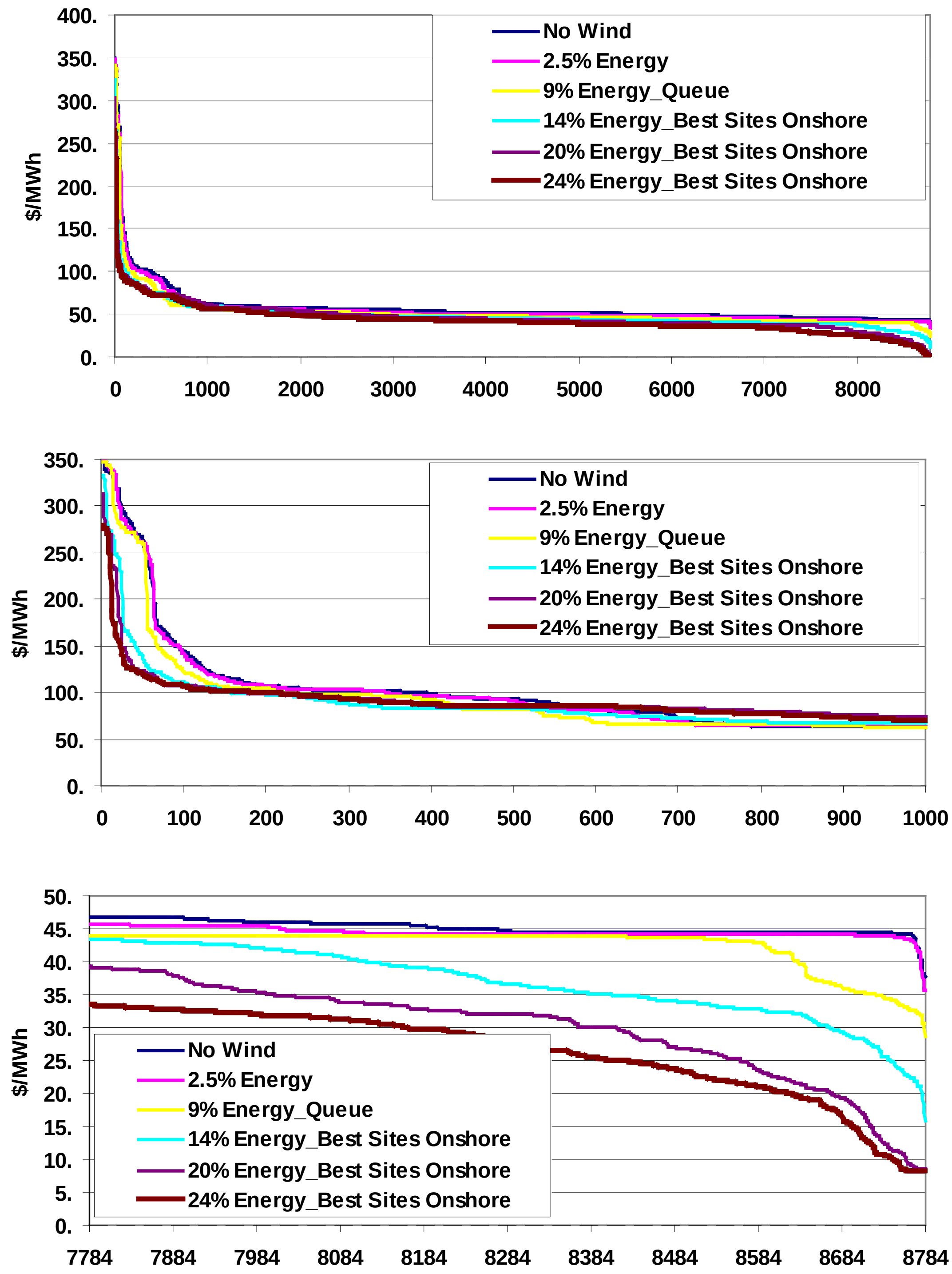


Figure 5–11 Annual LMP duration curve, S-O-A Forecast, Best Sites Onshore

Figure 5–12 shows the total revenue received by each generation type with increasing penetration of wind. As expected the CC generation sees the largest reduction in revenue.

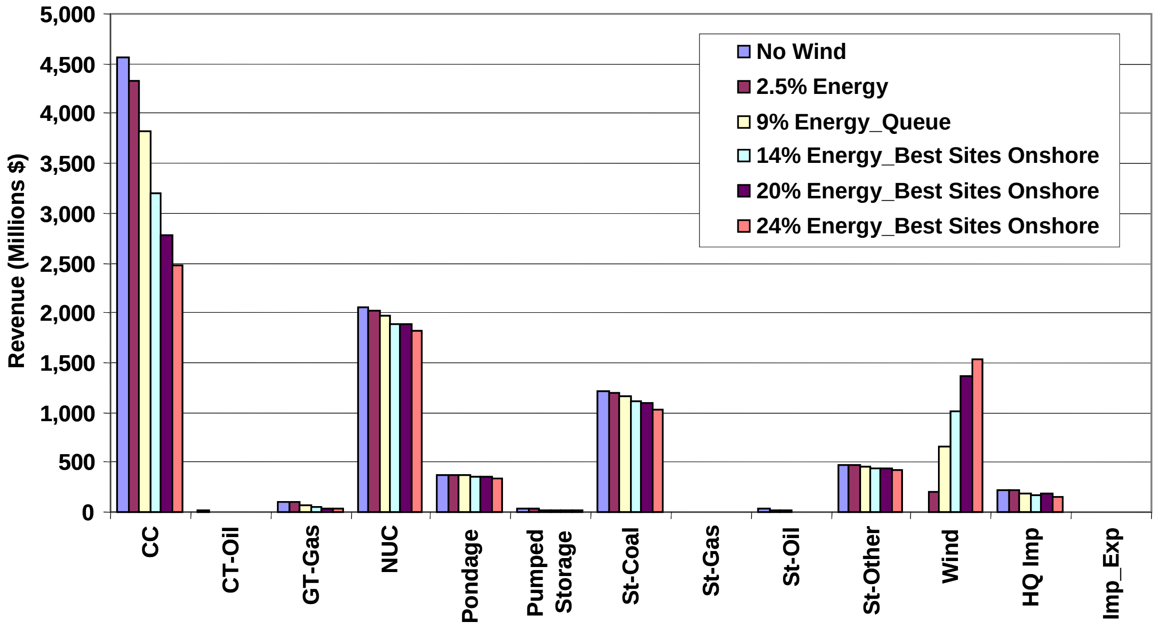


Figure 5–12 ISO-NE revenue by type S-o-A forecast, Best Sites Onshore

Figure 5–13 looks at the revenue and operating cost reduction per the net MWh of wind relative to the No Wind Scenario for CC and St-Coal generation. The operating cost reduction for the CC is relatively flat across the different penetration levels. At higher penetrations, the value of a MWh of wind decreases. The first MWh of wind has higher value than the nth MWh. The net profit reduction ranged from $11/MWh to $7/MWh for CC's per MWh of wind. St-Coal net profit reduction was roughly $3 to $4/MWh per MWh of wind. Figure 5–14 shows the same data as Figure 5–13 except it is in % relative to the No Wind Scenario.

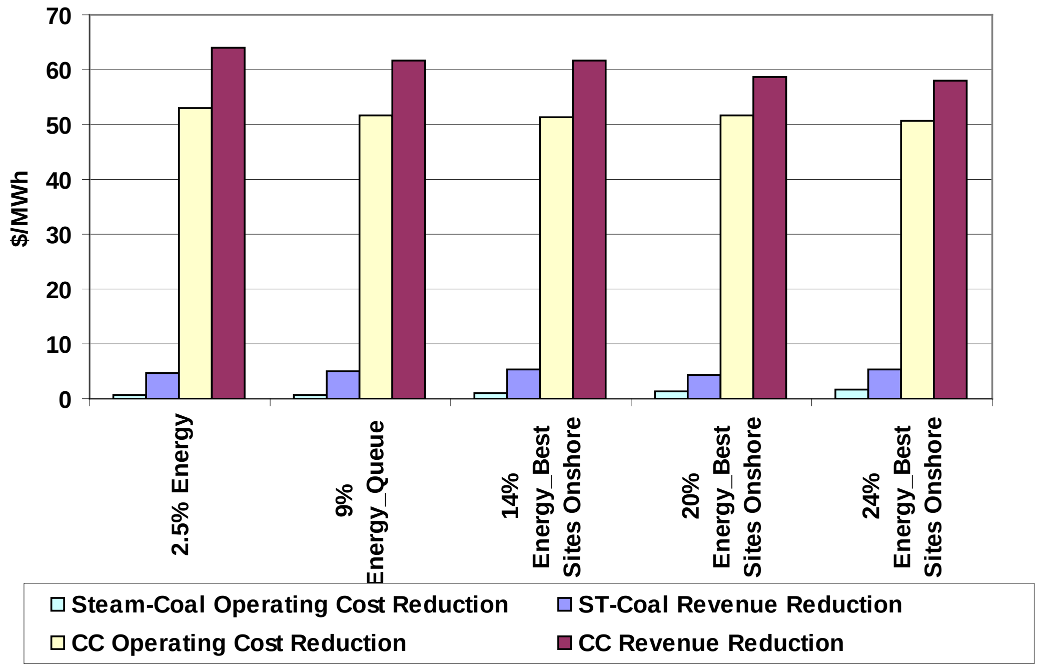


Figure 5–13 ISO-NE CC and St-Coal revenue and operating cost reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

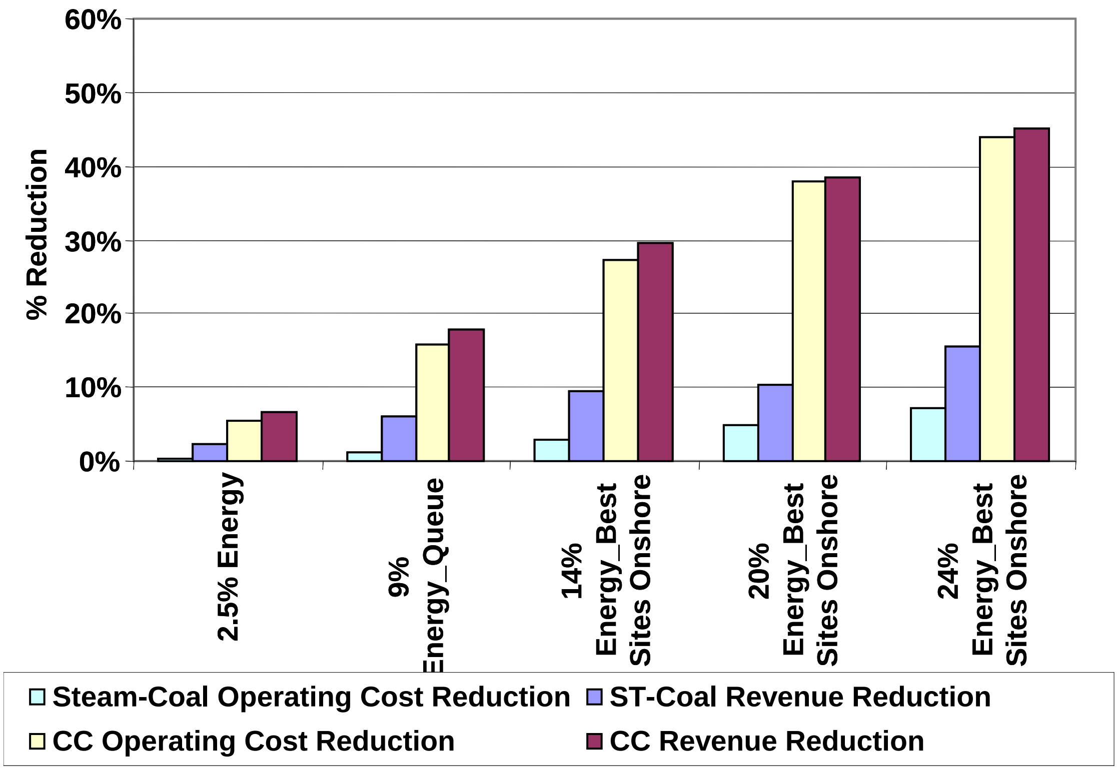


Figure 5–14 ISO-NE CC and St-Coal revenue and operating cost percent reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

Figure 5–15 shows the ISO-NE operational cost savings, that is, the reduction in fuel, variable O&M and startup costs relative to the No Wind Scenario for the increasing penetration of wind. As expected, the total reduction increases as the wind penetration increases.

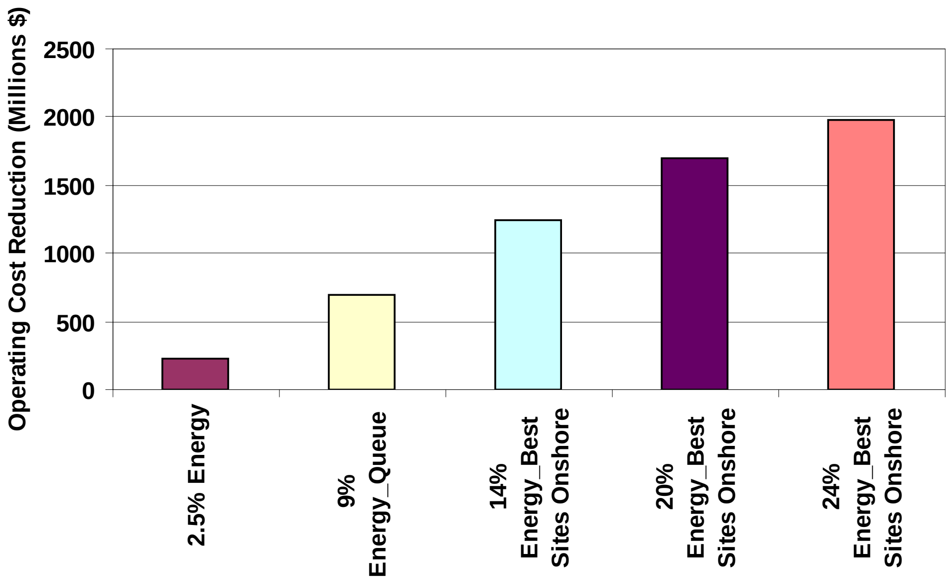


Figure 5–15 ISO-NE operating Cost reduction S-o-A forecast, Best Sites Onshore

Figure 5–16 shows the operating cost reduction per MWh of wind or "Wind Value". This is the average value of the wind energy in each case which varies from $59 to $55/MWh. In essence, this is the cost to replace one MWh of energy from wind generation with one MWh of energy from the next available resource from the assumed fleet of conventional resources. As with the revenue reduction for CC and St-Coal per MWh of wind, the wind value decreases as the penetration increases.

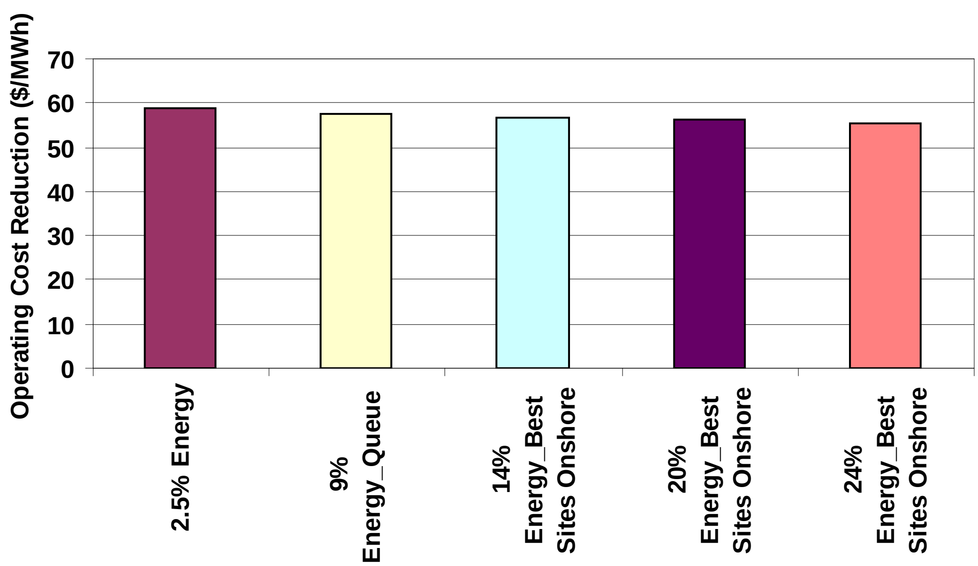


Figure 5–16 ISO-NE operating cost reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

Figure 5–17 shows the total load payments for energy for the increasing penetration of wind. The reduction for the 24% scenario is roughly $1.6 Billion. This is an 18% reduction as compared to the No Wind Scenario.

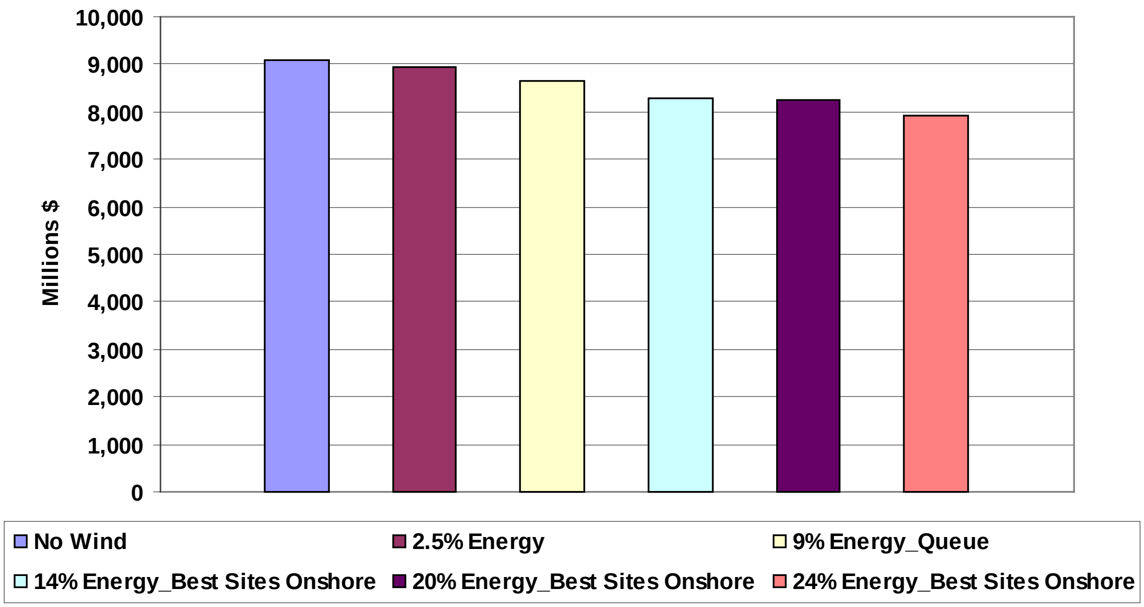


Figure 5–17 ISO-NE wholesale load payments for energy, S-o-A forecast, Best Sites Onshore

5.2.1.1 Transmission Constraints

Table 5–3 shows the limits for the interfaces modeled and Table 5–4 shows the maximum and minimum flow on each interface constraint in ISO-NE for the copper sheet case for increasing wind penetration. The red highlighted cells show where the flow would have been above the limit for the constrained case for the various scenarios.

Table 5–3 ISO-NE transmission interface limits, S-o-A forecast, Best Sites Onshore

Interface	NPCC 2019 Min Rating (MW)	NPCC 2019 Max Rating (MW)	2 GW Min Rating (MW)	2 GW Max Rating(MW)	4GW Min Rating (MW)	4GW Max Rating (MW)	8GW Min Rating (MW)	8GW Max Rating (MW)
North-South	-2700	2700	-3800	3800	-6800	6800	-7400	7400
Boston Import	-4900	4900	-4900	4900	-4900	4900	-4900	4900
New England East-West	-3500	3500	-4300	4300	-7900	7900	-8600	8600
Connecticut Export	-3900	3900	-4200	4200	-4500	4500	-5000	5000
Connecticut Import	-3600	3600	-5300	5300	-6600	6600	-7000	7000
Southwestern Connecticut Import	-3650	3650	-3650	3650	-3650	3650	-3650	3650
Norwalk-Stamford Import	-1650	1650	-1650	1650	-1650	1650	-1650	1650
New York-New England	-1600	1600	-1600	1600	-1600	1600	-1600	1600
Orrington South	-1200	1200	-2500	2500	-5500	5500	-6100	6100
Surowiec South	-1150	1150	-2100	2100	-5200	5200	-5800	5800
Maine-New Hampshire	-1450	1450	-2700	2700	-5700	5700	-6400	6400
SEMA Export	-9999	9999	-9999	9999	-9999	9999	-9999	9999
West - East	-4400	4400	-4400	4400	-5100	5100	-5800	5800
NB - NE	-500	1000	-500	1000	-500	1000	-500	1000
SEMA/RI Export	-3300	3300	-4200	4200	-6500	6500	-6500	6500

Table 5–4 ISO-NE Copper Sheer transmission interface summary S-o-A forecast, Best Sites Onshore

Interface	No Wind Min Flow (MW)	No Wind Max Flow (MW)	2.5% Min Flow (MW)	2.5% Max Flow (MW)	9% Min Flow (MW)	9% Max Flow (MW)	14% Min Flow (MW)	14% Max Flow (MW)	20% Min Flow (MW)	20% Max Flow (MW)	24% Min Flow (MW)	24% Max Flow (MW)
North-South	196	4904	-46	3987	20	5605	332	7126	320	8356	360	9639
Boston Import	526	4615	549	4464	633	5328	660	5755	678	5260	-1159	3363
New England East-West	-1451	2720	-1213	3760	-784	4214	-1766	4395	-1795	5254	-1751	5631
Connecticut Export	-2652	1464	-2723	1379	-3031	1175	-3697	1249	-3923	1259	-2924	1342
Connecticut Import	-867	2986	-669	3001	-608	3331	-668	3692	-663	3918	-890	2919
Southwestern Connecticut Import	176	2151	184	2157	252	2363	196	2430	68	2612	70	2706
Norwalk-Stamford Import	470	1255	438	1255	430	1279	386	1355	479	1466	343	1465
New York-New England	-1525	1600	-1525	1582	-1525	1525	-1600	1600	-1600	1600	-1600	1600
Orrington South	-304	1804	-211	1897	-518	2390	-393	3321	-206	4669	-391	5074
Surowiec South	-672	1761	-587	1988	-1435	3104	-1254	3747	-305	5957	-407	7414
Maine-New Hampshire	-952	2583	-897	2559	-1589	4687	-1049	5778	-438	5945	-415	7116
SEMA Export	-1622	785	-1422	1131	-1035	2750	-1408	975	-1215	1319	-1599	901
West - East	-2227	2192	-3267	1501	-3074	1129	-3405	1854	-4954	1791	-5185	1851
NB - NE	-500	1000	-500	1000	-1000	1000	-1000	1000	-500	1000	-500	1000
SEMA/RI Export	-591	3369	-406	3502	-691	4476	-1312	2811	-1908	2634	-2142	2381

Table 5–5 details what transmission overlay each scenario uses. Transmission congestion can cause cheaper generation to be displaced inside and/or outside the system. In extreme conditions wind generation may be curtailed, if the LMP drops below $10/MWh.

Table 5–5 Transmission overlay summary

Scenario	Transmission Overlay
No wind	NPCC 2019
2.5% Energy	NPCC 2019
9% Energy	2GW
14% Energy	2GW
20% Energy	4GW
24% Energy	8GW

Figure 5–19 through Figure 5–26 show flow duration curves for the interfaces that were highlighted in red in Table 5–4. Note that negative flows represent flow in the opposite direction. For example in Figure 5–26, positive flow represents exports from ISO-NE to the Maritimes and negative flow represents imports into ISO-NE from the Maritimes. The flows use the constrained case.

Note that the North – South interface is constrained for roughly 3000 hours in the 14% scenario. This has a minor impact on overall operations, for example this congestion had minor impacts on LMP. Figure 5–18 shows the duration flow on the North/South interface for the 14% energy Scenario. It also shows duration of the congestion cost associated with the interface. The interface is not closed therefore other paths are available for power to flow. This is shown in the figure. Although there are roughly 3000 hours where the interface is at its limit there are only 200 hours where the congestion cost is greater than $1/MWh. Basically, for 2800 hours there is an alternate path to deliver the power to Southern NE. This result may seem counterintuitive to historical operation. Note that the transmission system has been expanded based on the Governors’ 2 GW overlay.

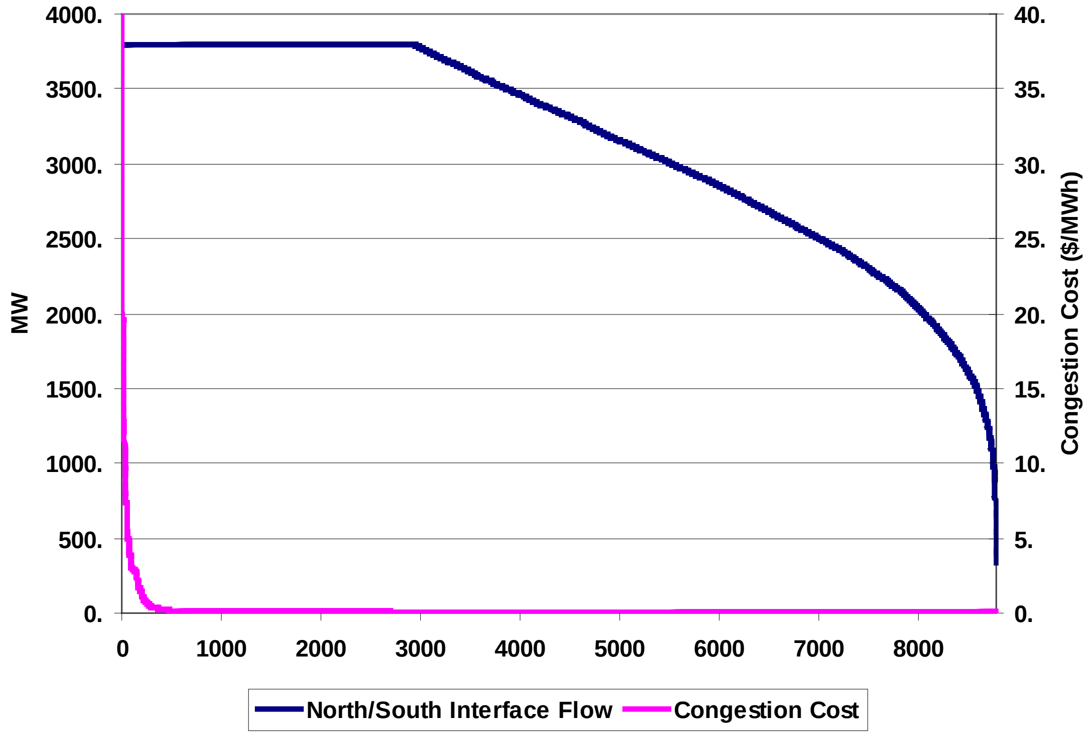


Figure 5–18 North/South Interface Flow vs. Congestion Cost 14% Energy_Best Sites Onshore

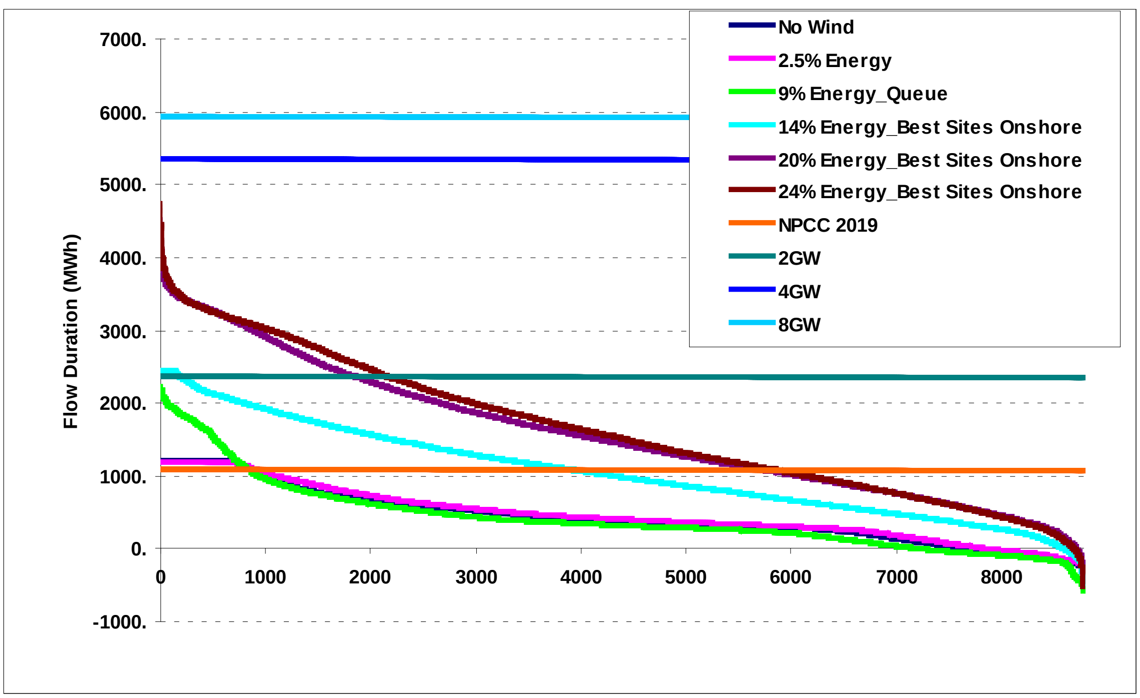


Figure 5–19 Orrington South interface flow, S-o-A forecast, Best Sites Onshore

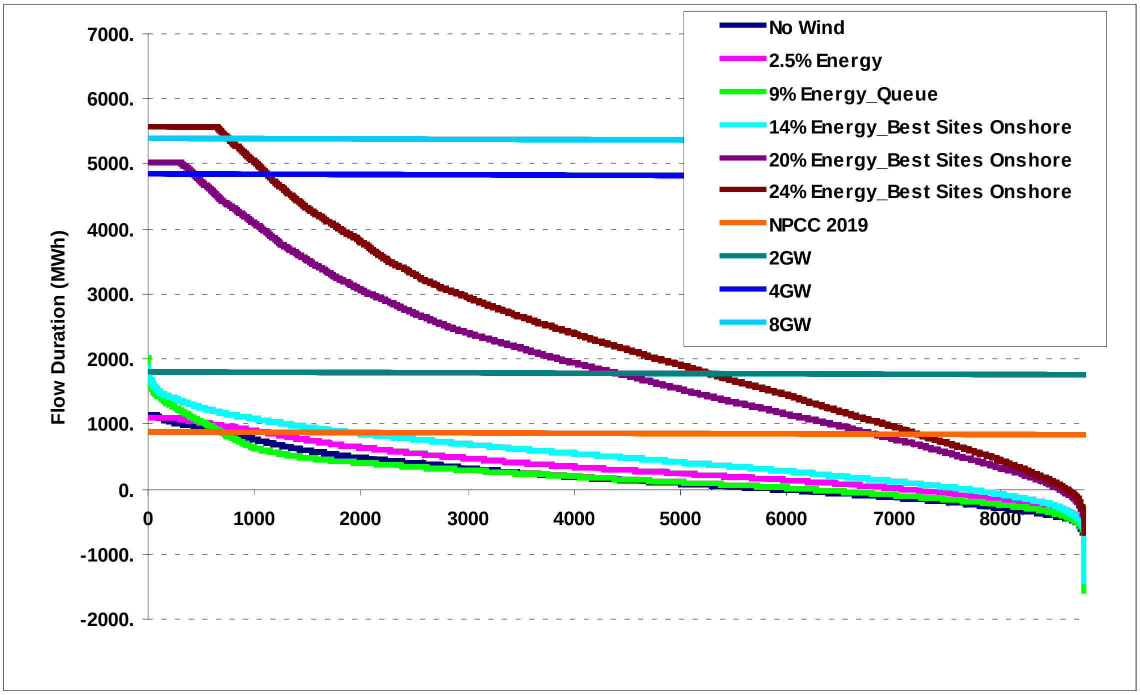


Figure 5–20 Surowiec South interface flow, S-o-A forecast, Best Sites Onshore

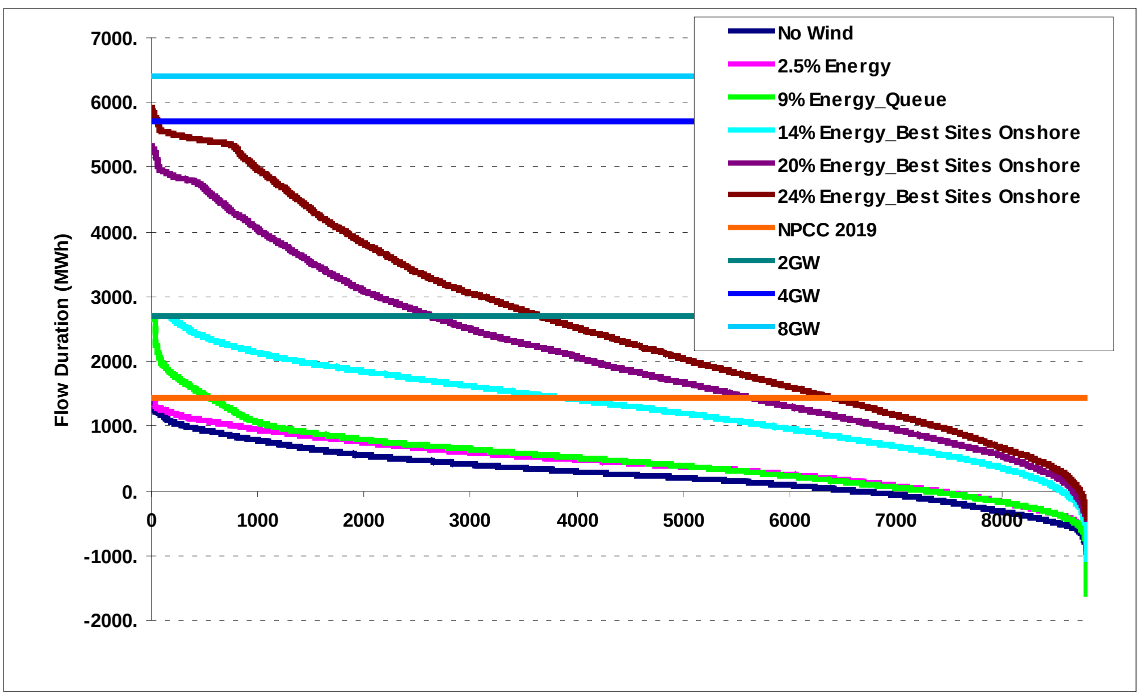


Figure 5–21 Maine/New Hampshire interface flow, S-o-A forecast, Best Sites Onshore

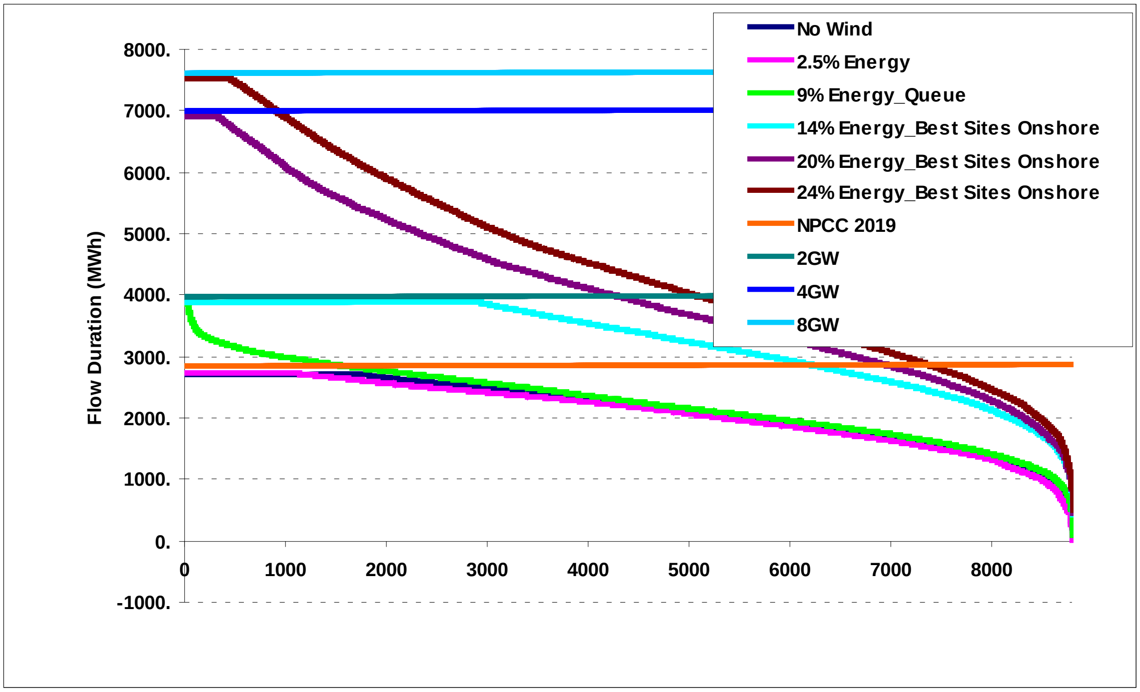


Figure 5–22 North/South interface flow, S-o-A forecast, Best Sites Onshore

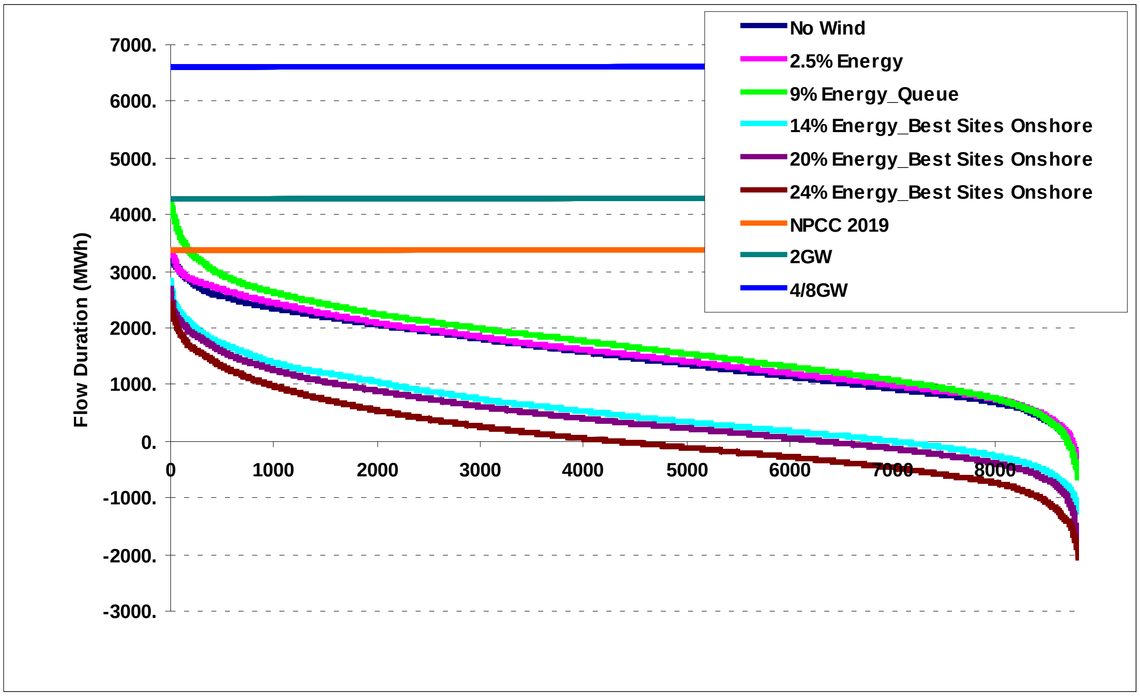


Figure 5–23 SEMA/RI Export interface flow, S-o-A forecast, Best Sites Onshore

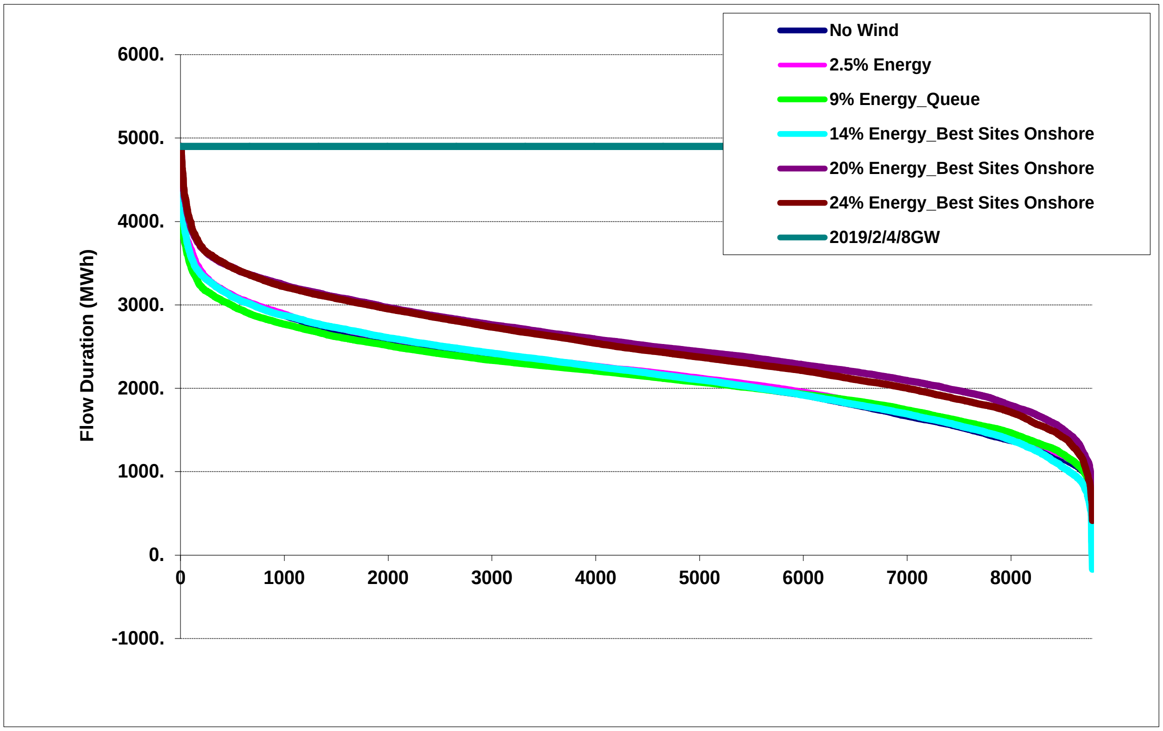


Figure 5–24 Boston Import interface flow, S-o-A forecast, Best Sites Onshore

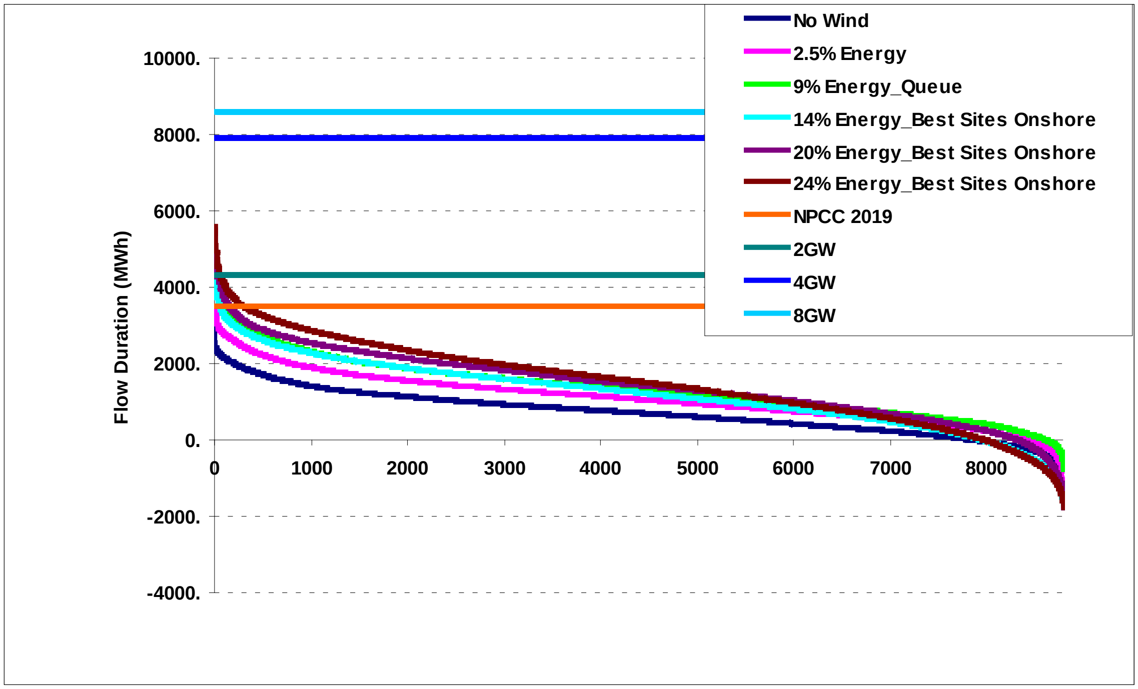


Figure 5–25 East-West interface flow, S-o-A forecast, Best Sites Onshore

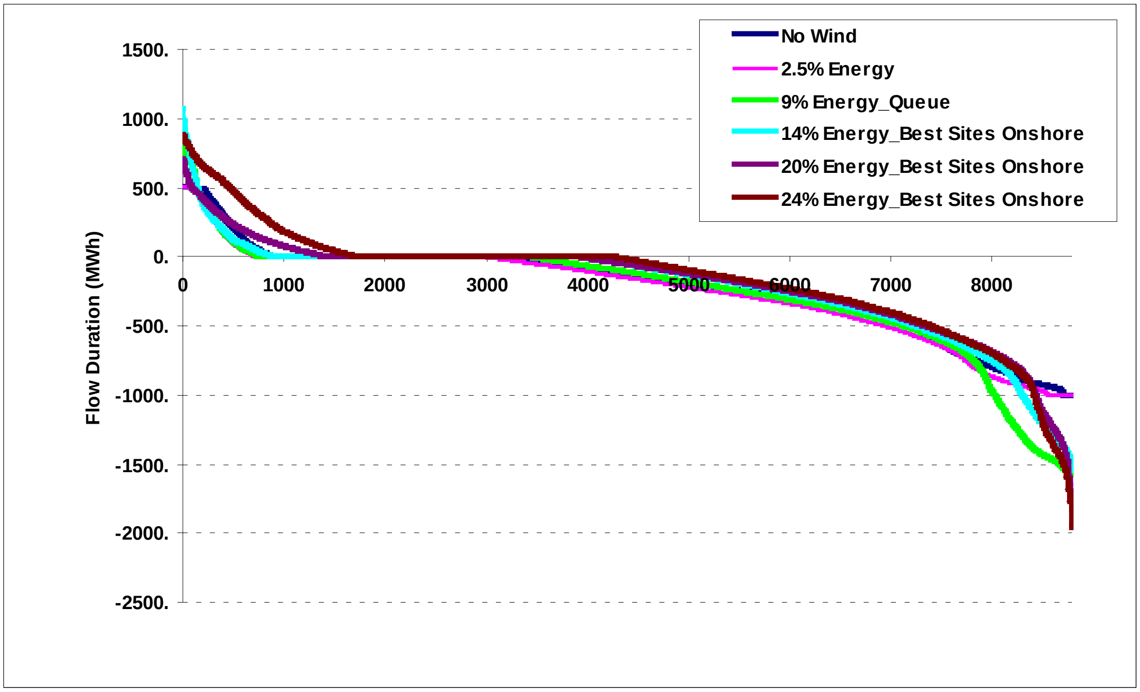


Figure 5–26 ISO-NE to NB interface flow, S-o-A forecast, Best Sites Onshore

5.2.1.2 Ramp and Range Capability

The impact on the range and ramp availability was analyzed for the various penetration scenarios. The range is calculated based on what the unit was dispatched at and the room it had left up or down respectively. The units that contribute to the range are steam other, steam coal, combined cycle, pumped storage hydro and conventional hydro. Wind is not considered. The ramp is a unit's capability to move up or down over a one minute period. Table 5–6 summarizes the capacity type and ramp rates assumed.

Table 5–6 Ramping capability by generation type

Type	Ramp Rate (%/min)
CC	4%
CT gas/oil	14%
Hydro	22%
ST-gas/coal/oil/other	3%
Pumped Storage Hydro	19%

Figure 5–27 and Figure 5–28 show duration curves of the hourly range up and range down capacity available for the various scenarios. The graphs are based on what is committed and online for operation. The maximum range up available varies from roughly 8,100 MW in the No Wind Scenario to 9,964 MW in the 24% scenario. The minimum range up available varies from roughly 905 MW in the No Wind Scenario to 768 MW in the 24% scenario. The maximum range down available varies from roughly 18,600 MW in the No Wind Scenario to 15,298 MW in the 24% scenario. The minimum range down available varies from roughly 1,475 MW in the No Wind Scenario to 0 MW in the 24% scenario. The 24% case has about 16 hours when the range down is 0 MW. This is less than 0.2% of the year. In this situation the wind would potentially be curtailed to free up range down capacity, since as conventional generation units are backed down to lower operating levels there is less maneuverability down.

The results are as expected, with increased penetration of wind, other types of generation are backed down to lower operating levels creating increased range up capacity. The opposite is true for the range down capacity.

The MAPS analysis shows no spinning reserve violations up to 24% penetration of wind. The minimum range up capacity was greater than the spinning reserve requirement built into the model.

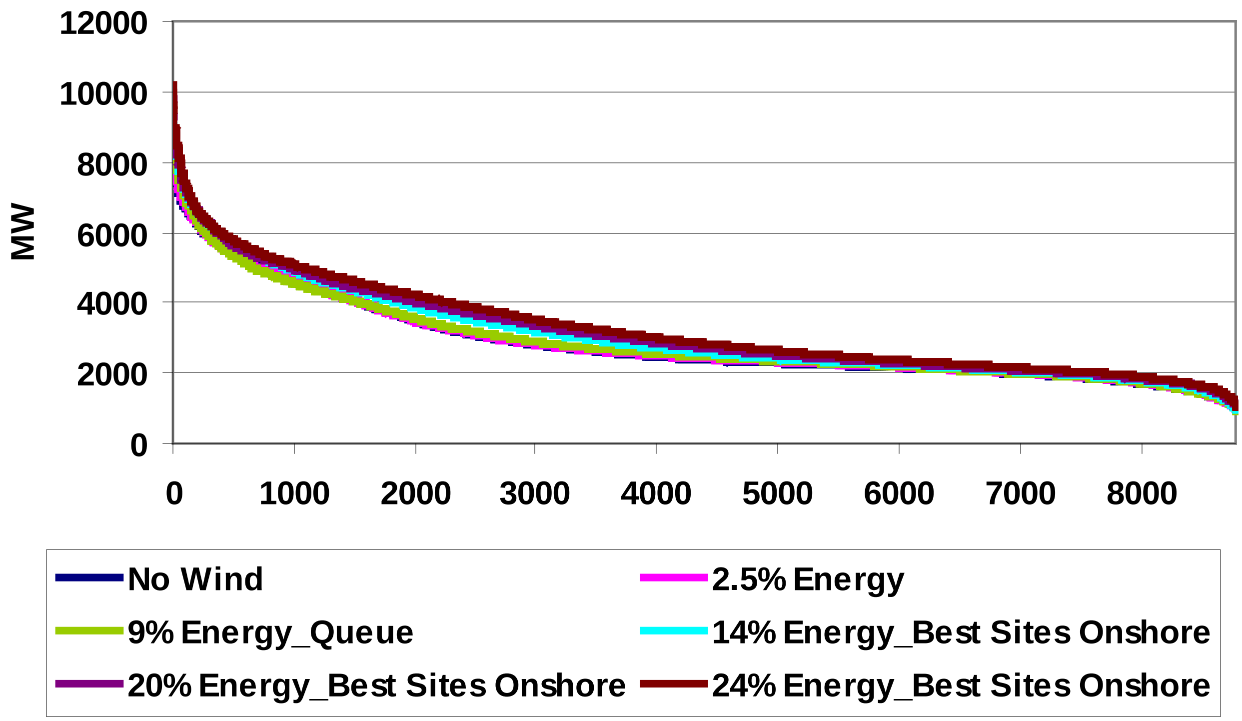


Figure 5–27 Hourly Range Up Capability S-o-A forecast, Best Sites Onshore

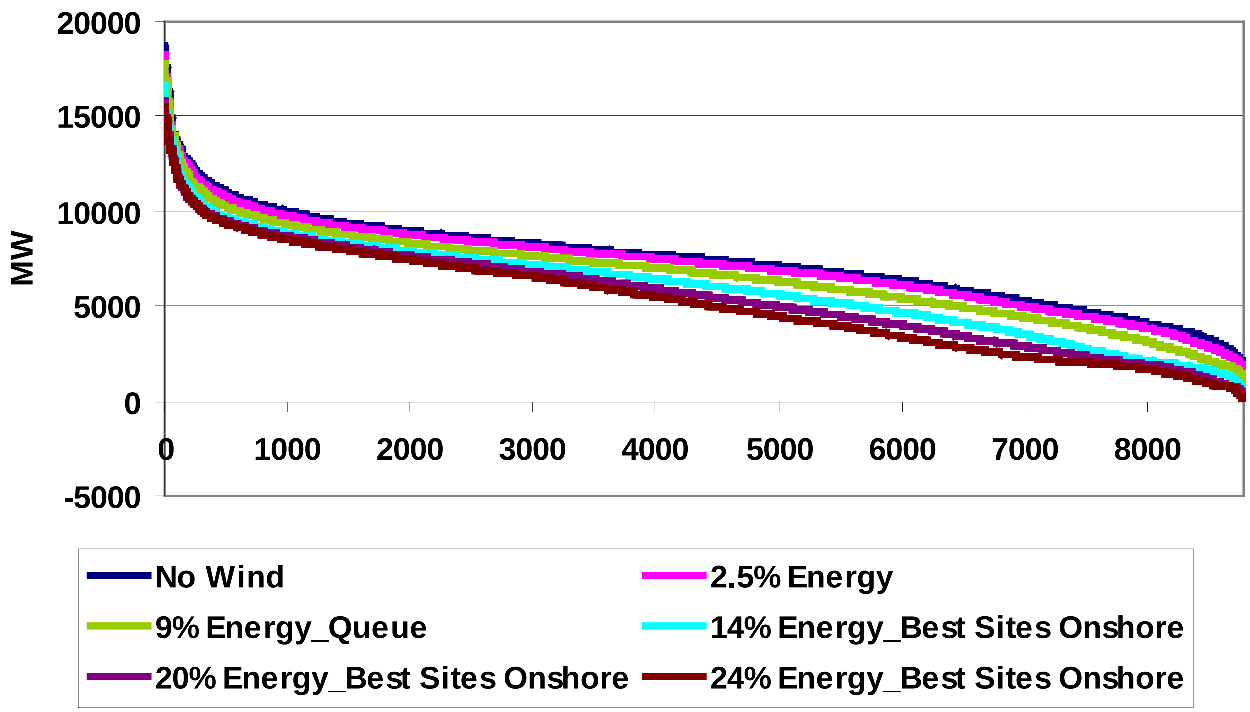


Figure 5–28 Hourly Range down Capability S-o-A forecast, Best Sites Onshore

Figure 5–29 and Figure 5–30 show duration curves of the hourly ramp up and ramp down capacity available for the various scenarios. The data represents the available unit ramp capability at the beginning of the hour. The one minute ramping capability only includes headroom effects for the first minute and may not be sustainable over periods longer than one minute. For example, if a 500 MW unit has a ramp rate of 5%/min or 25 MW/min, and is dispatched at 400 MW, it can only provide ramping for 4 minutes. If the same unit is dispatched at 490 MW then it can provide 10 MW for the first minute. The maximum ramp up capability available varies from roughly 1,250 MW/min in the No Wind Scenario to 1,230 MW/min in the 24% scenario. Most of the high values of ramp occur in off-peak hours and come from the PSH and conventional hydro. There is also some contribution from thermal units that are needed for the next day and cannot be shut down at night. The minimum ramp up capability varies from roughly 206 MW/min in the No Wind Scenario to 123 MW/min in the 24% scenario. The maximum ramp down capability available varies from roughly 2,440 MW/min in the No Wind Scenario to 1,840 MW/min in the 24% scenario. The minimum ramp down available varies from roughly 101 MW/min in the No Wind Scenario to 0 MW in the 24% scenario. The 24% case has about 16 hours when the ramp down is 0 MW/min. This is less than 0.2% of the year.

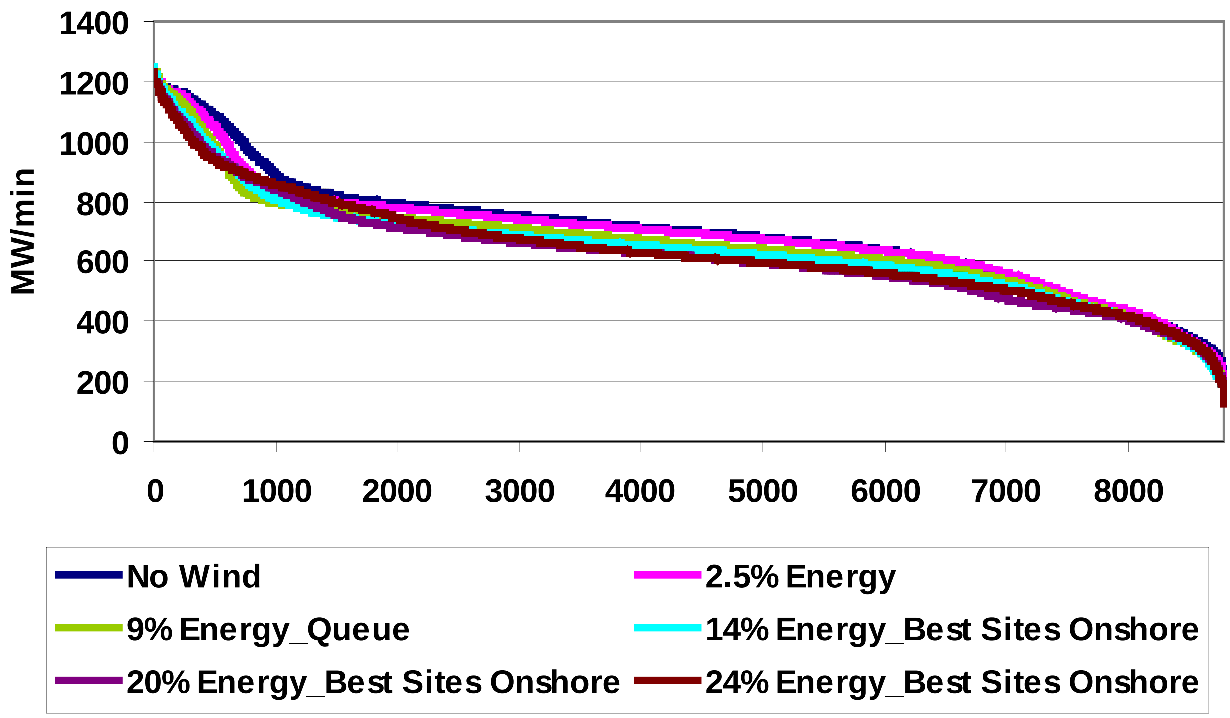


Figure 5–29 Hourly Ramp Up Capability S-o-A forecast, Best Sites Onshore

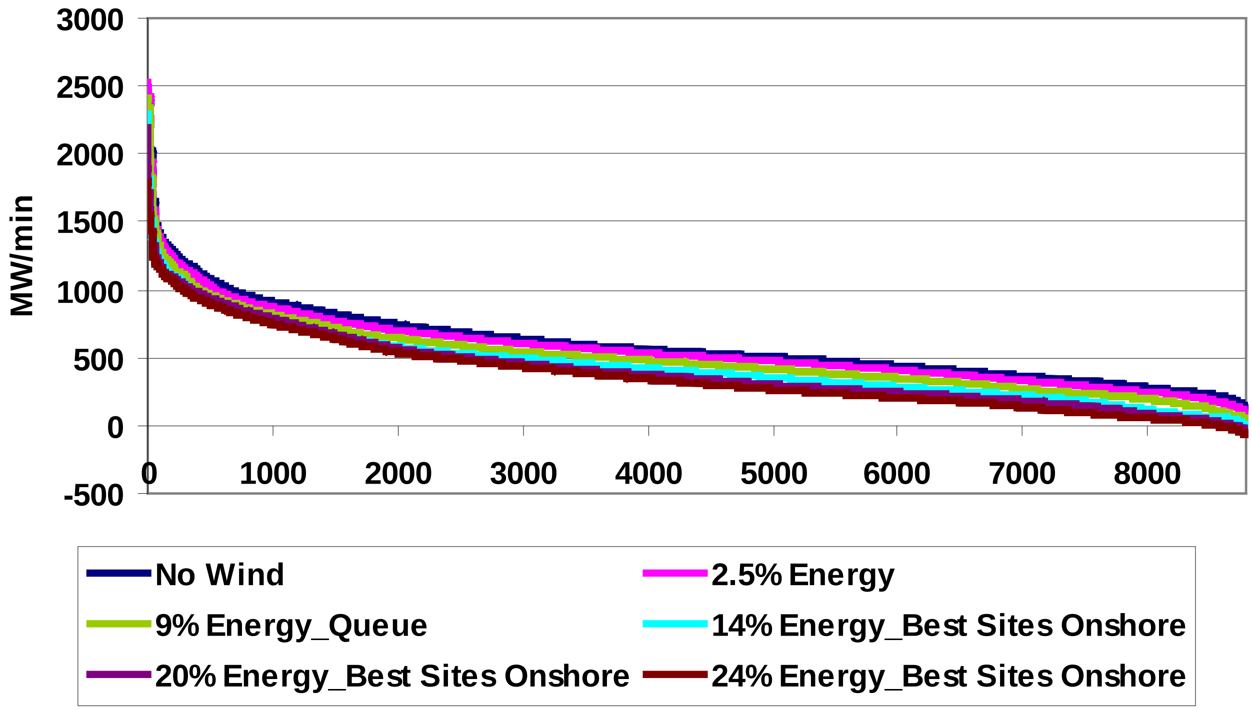
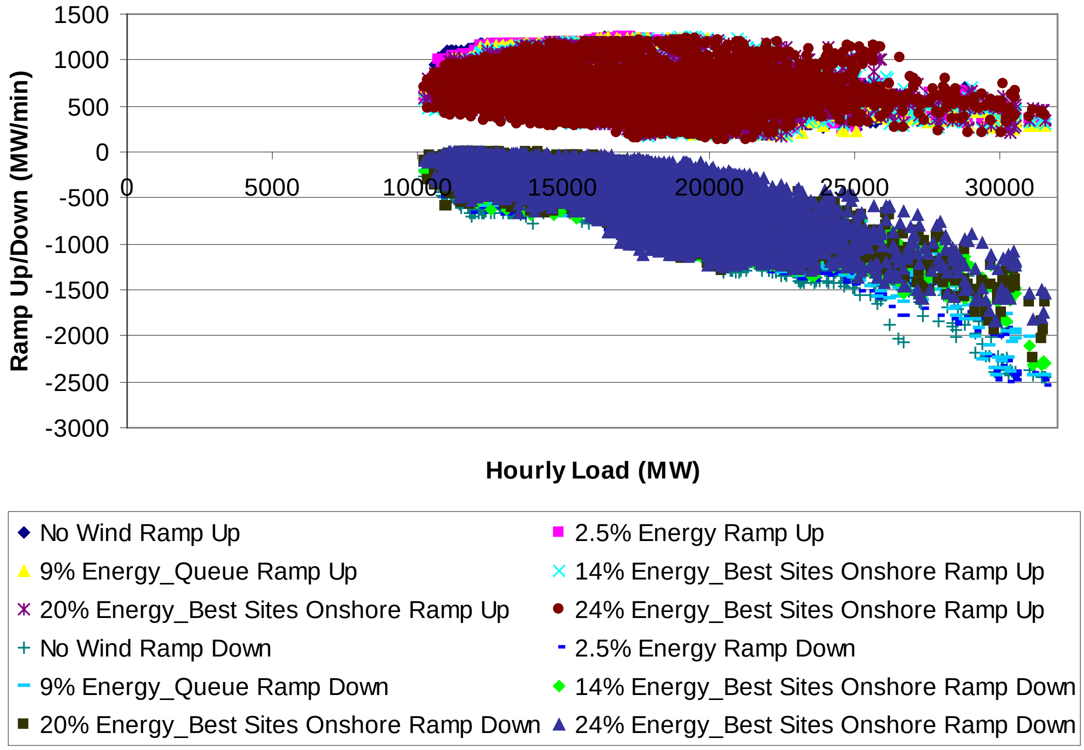


Figure 5–30 Hourly ramp down capability S-o-A forecast, Best Sites Onshore

Figure 5–31 compares the hourly ramp up/down capability against the hourly load. The upper figure shows the total range and the bottom figure expands the graph to just show the hours with less than +/- 100 MW/min ramping capability. The ten-minute spinning reserve for ISO-NE is 700 MW, which would correspond to a ramp up capability of 70 MW/min. As can be seen from the scatter plot, the ramp up capability never seems to be a problem: its lowest point is roughly 123 MW/min. Depending on the wind penetration the regulation requirement ranges from roughly 102 MW to 313 MW (see section 4.6.1). This can be compared to the regulation requirements, which increase from roughly 80 MW to 310 MW at 20% penetration, as seen in section 4.6.1. Over a 5-minute period, 310 MW would translate to 62 MW/min, which is approximately half of what is available, indicating that the increased regulation requirement could easily be met.



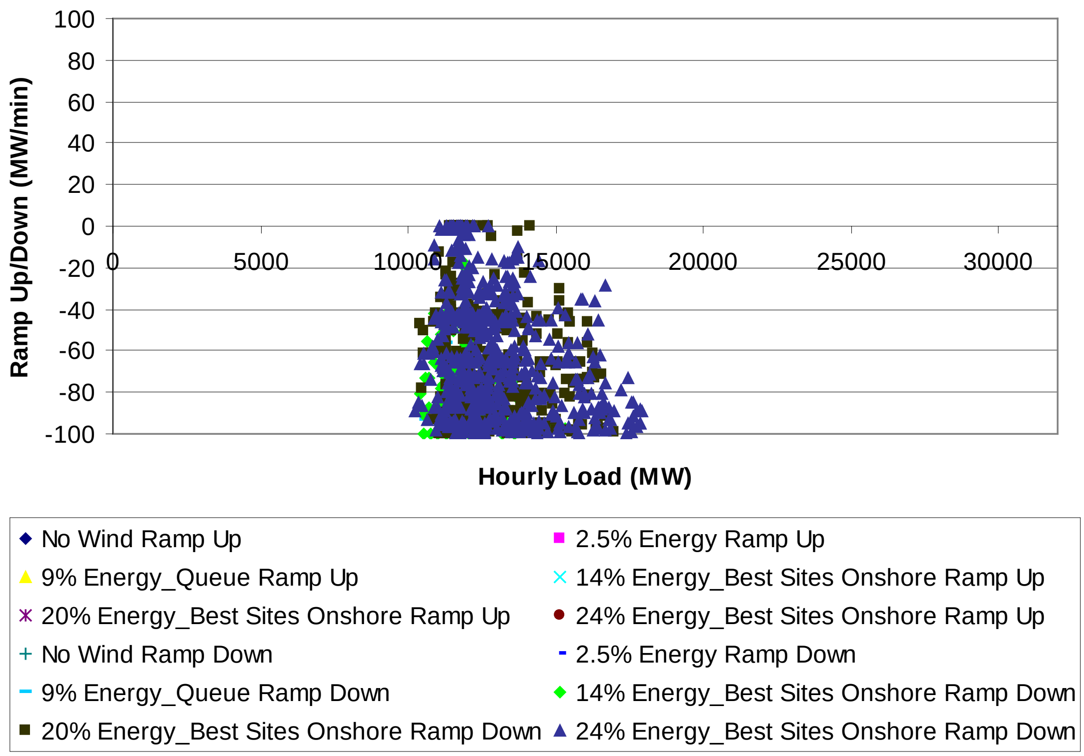


Figure 5–31 Hourly Ramp Up/Down Capability MW/min vs. Load, S-o-A forecast, Best Sites Onshore

The ramp down capability may be deficient a few hours and possibly require either changes to the unit commitment or spilling of some wind energy. Table 5–7 shows the number of hours when the ramp down capability is less than 100 MW/minute for the various wind penetration scenarios. Although relatively small at the lower penetrations the number of hours becomes more significant at the higher penetrations.

Table 5–7 Number of hours with ramp down capability < 100 MW/minute.

Scenario	# Hours
No Wind	0
2.5% Energy	3
9% Energy_Queue	43
14% Energy_Best Sites Onshore	185
20% Energy_Best Sites Onshore	374
24% Energy_Best Sites Onshore	537

5.2.1.3 Weekly Dispatch and Ramp/Range analysis

The previous section examined the operational impacts of renewable generation from an annual basis. This section examines a spring and summer week to look at the changes in operation more closely.

Table 5–8 is the legend for the following figures. The solid color blocks represent the generation. PSH (in solid red) is counted as generation when in generating mode, due to the limitations of this type of plot, PSH is not shown as a solid area when in pumping mode. The light blue line represents the load plus exports, plus the pumping of the PSH. The dark blue line is the native load. The pink line represents the net load (native load minus the wind generation). The red line is the PSH generation; where a positive value is generation. The dark green line is the import/exports into ISO-NE from NY, HQ, and the Maritimes. A positive value is an import.

Table 5–8 Legend

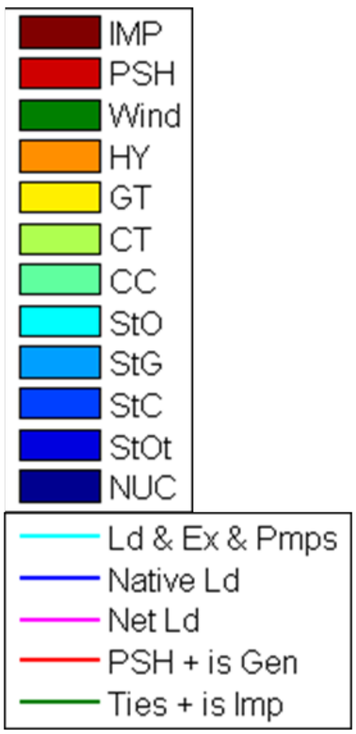


Figure 5–32 shows the operation of the generation by type within ISO-NE when there is no wind generation present for the week of April 13. The Nuclear, St-Coal, and St-Other generation were flat. The St-Other generation represents cogen, refuse, and wood burning generation. The hydro and PSH provided the bulk of the peaking operation and the combined-cycle filled in the intermediate operation.

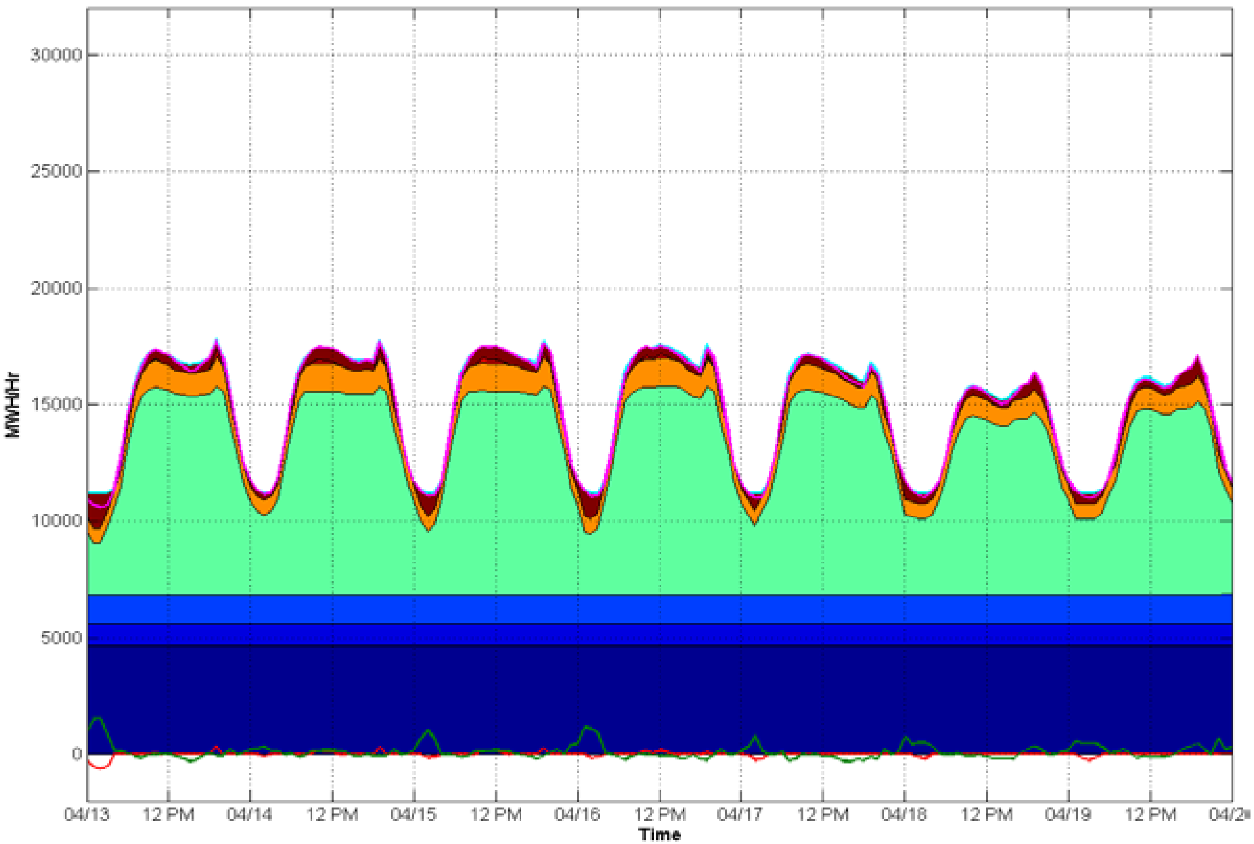


Figure 5–32 ISO-NE dispatch, week of April 13, no wind

Figure 5–33 shows how this operation changed for the 2.5% penetration level. The nuclear, St-Other, and St-Coal generation remain but the dispatch of the other generation has begun to change. The most noticeable shift is the introduction of the green band, which represents the wind generation. The hydro generation has shifted slightly. Each hydro plant was scheduled to meet specific monthly energy targets. Introduction of renewable generation could cause the hydro to shift the hourly schedule but the monthly energy production would remain constant. The bulk of the displacement came from the combined-cycle units, which is consistent with what was seen on an annual basis. Also note that the total generation each hour changed slightly from the previous figure. This was because the exports changed when the wind generation was added in New England while no additional wind generation was added in other regions for the 2.5% penetration level.

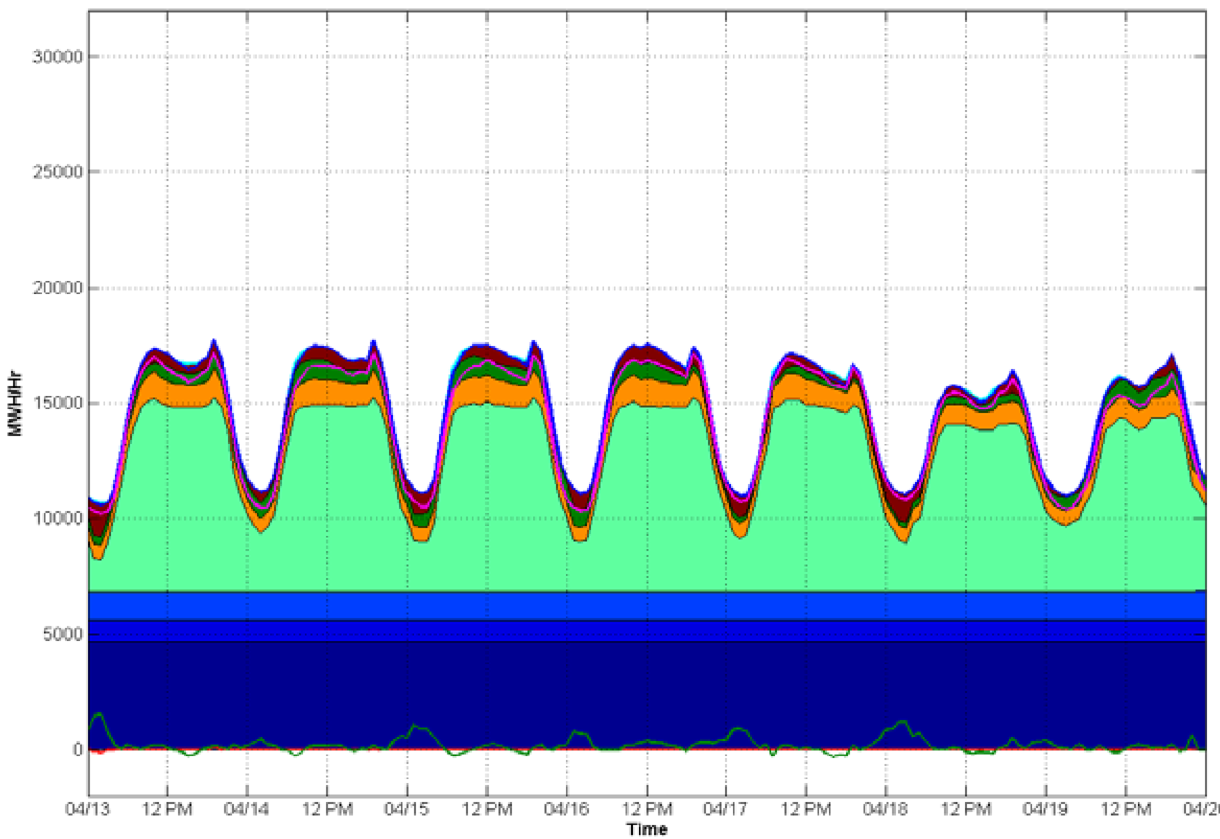


Figure 5–33 ISO-NE dispatch, week of April 13, 2.5% Energy, S-o-A forecast

Figure 5–34 shows how this operation changed for the 9% penetration level. The nuclear and St-Other remain constant but there are few hours where the St-Coal generation is displaced. The combined cycle generation is 75% of what it was with no wind generation.

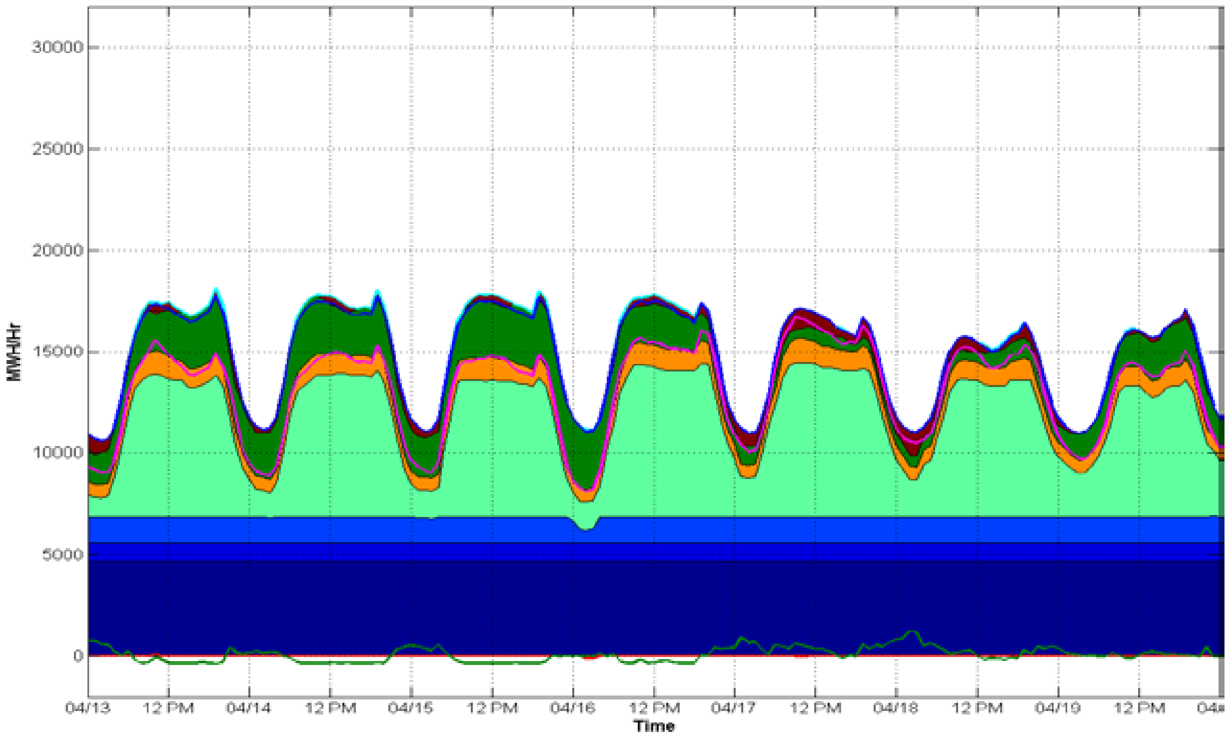


Figure 5–34 ISO-NE dispatch, week of April 13, 9% Energy, S-o-A forecast

Figure 5–35 shows how this operation changed for the 14% penetration level. The nuclear and St-Other still remain constant but there are few hours where the St-Coal generation is displaced. The imports increase. This happens because the outside system is now at the same penetration at ISO-NE. The combined cycle generation is 60% of what it was with no wind generation.

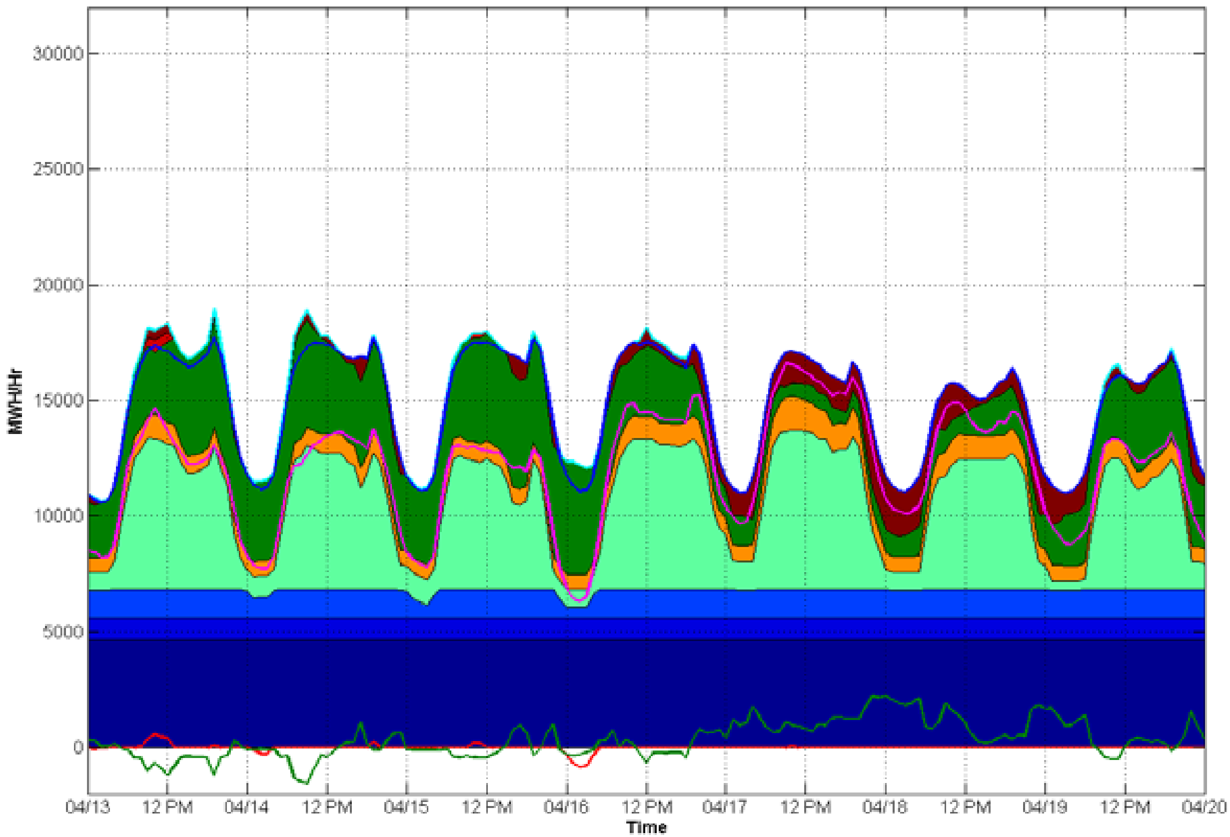


Figure 5–35 ISO-NE dispatch, week of April 13, 14% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–36 shows how this operation changed for the 20% penetration level. The nuclear remain constant but there are few hours where the St-Other and St-Coal generation is displaced. There is a small increase in PSH operation. The combined cycle generation is 43% of what it was with no wind generation.

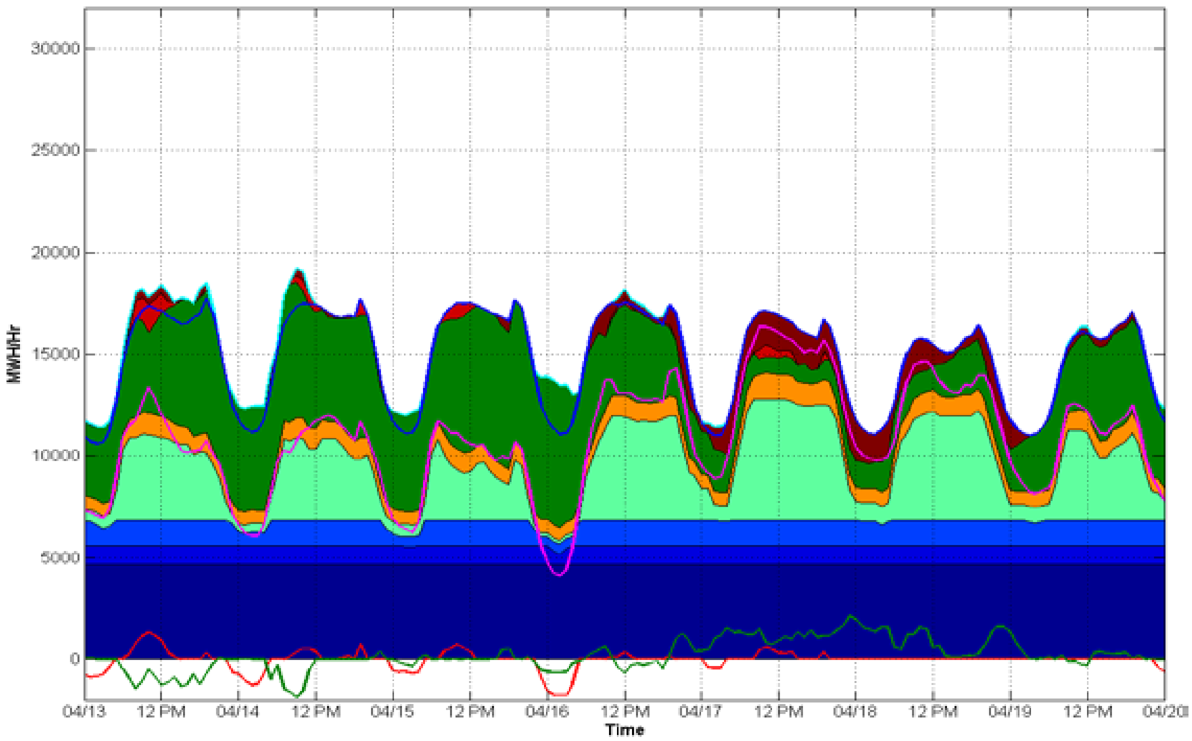


Figure 5–36 ISO-NE dispatch, week of April 13, 20% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–37 shows how this operation changed for the 24% penetration level. This case is similar to the 20% except the combined cycle generation is 35% of what it was with no wind generation.

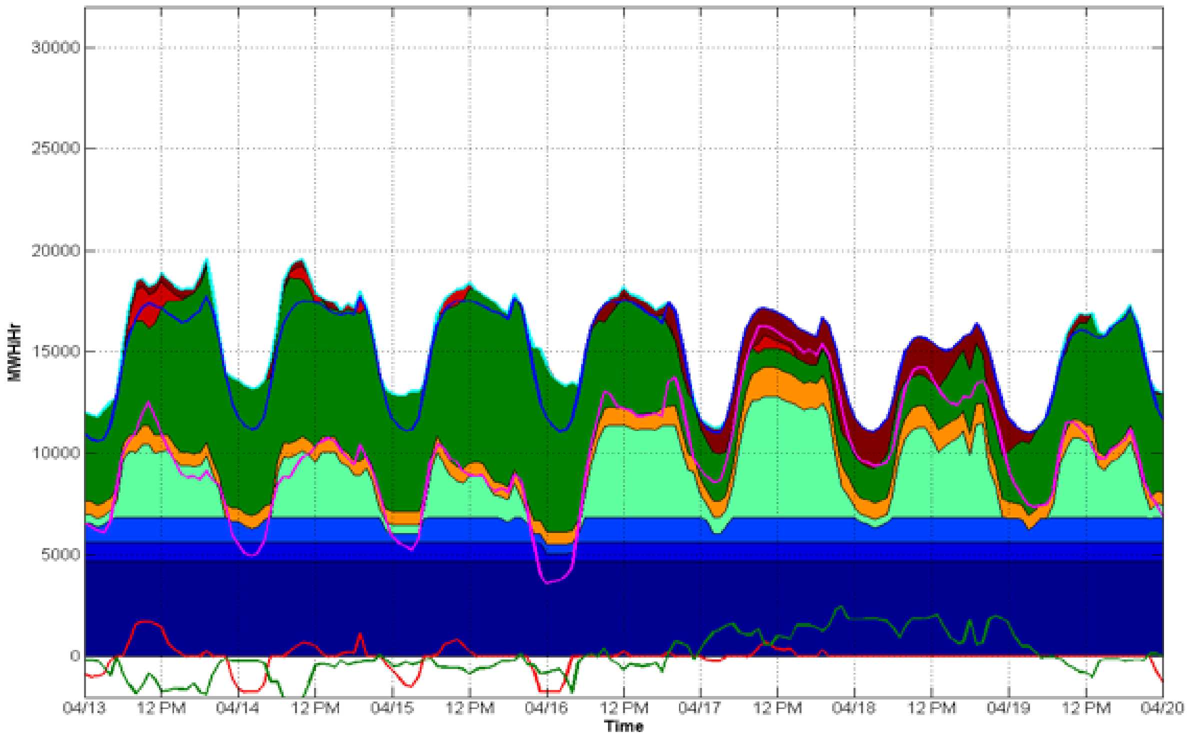


Figure 5–37 ISO-NE dispatch, week of April 13, 24% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–38 through Figure 5–43 show the hourly operation by generation type for the week of July 6. Even at the 24% penetration level there is very little change in CC operation. The CC energy output has dropped by less than 20%. Most notable is the decrease in the gas turbine generation needed for peaking operation. It has been largely displaced by the wind generation.

A comparison of the series of figures for the April and July weeks shows that while high penetration of wind may cause significant changes in dispatch at certain times of the year, its impacts at other times will be much less severe. It may be that at low-load/high-wind times of the year more of the base load generation should be taken out of service to allow generators that are better able to cycle to provide the balance of the energy.

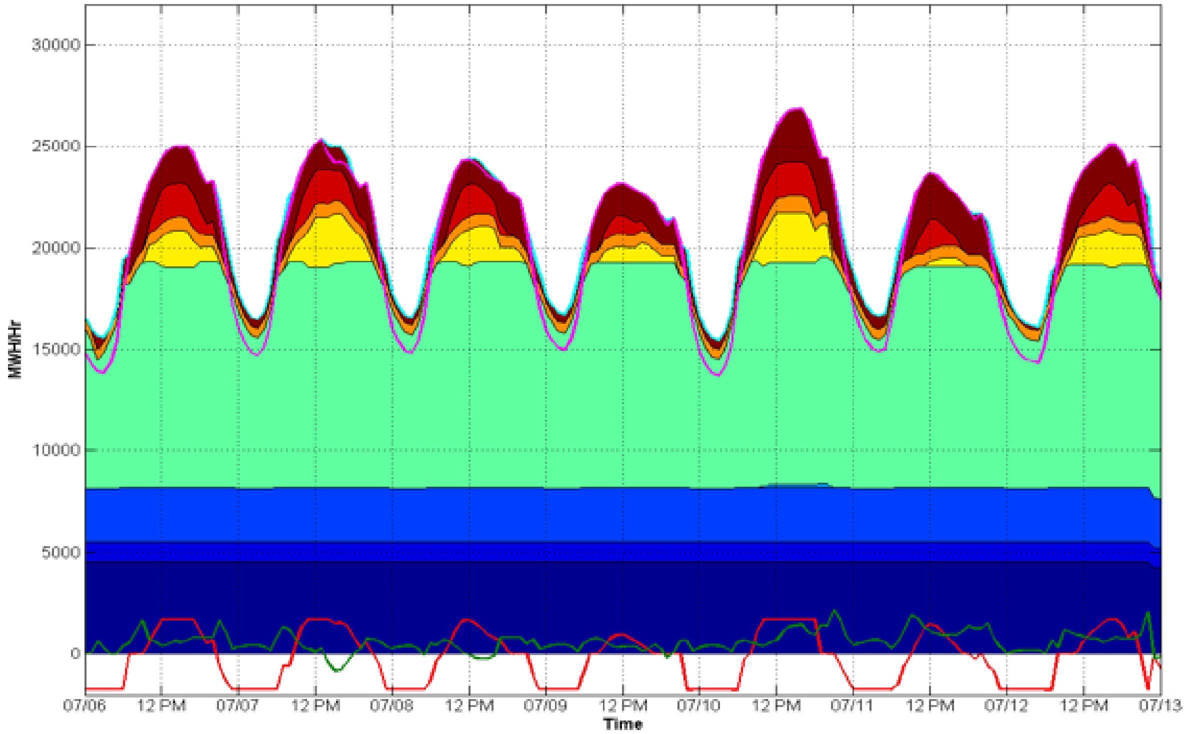


Figure 5–38 ISO-NE dispatch, week of July 6, no wind

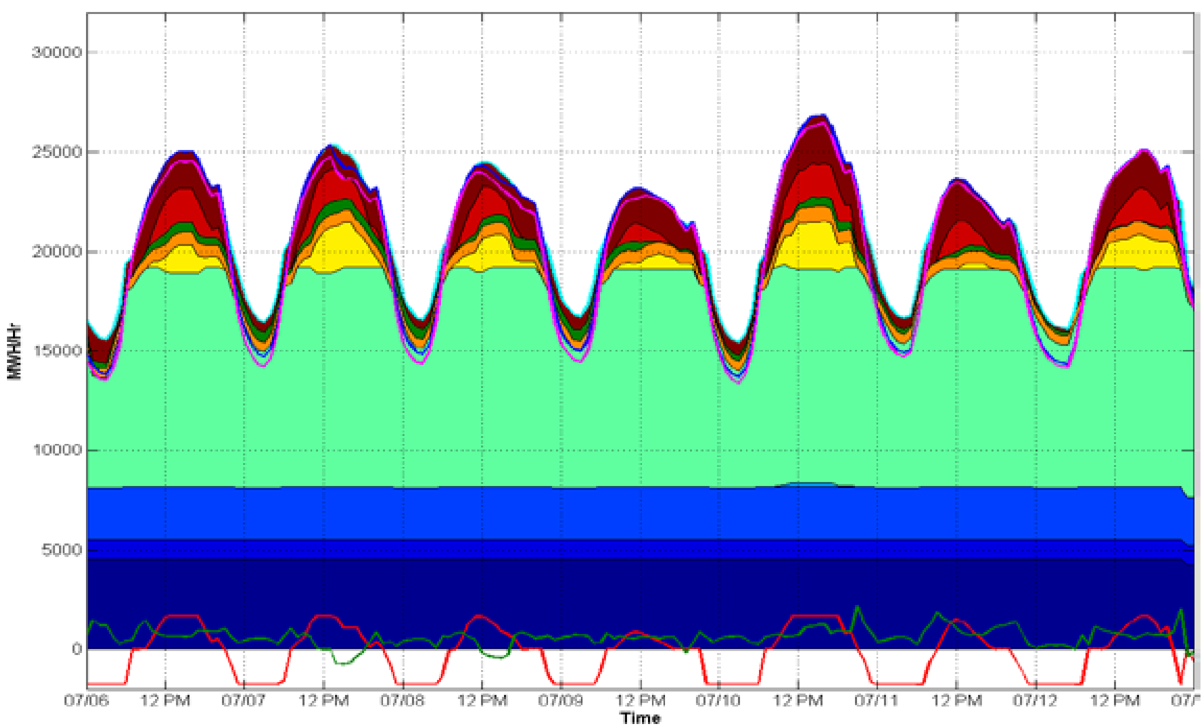


Figure 5–39 ISO-NE dispatch, week of July 6, 2.5% Energy, S-o-A forecast

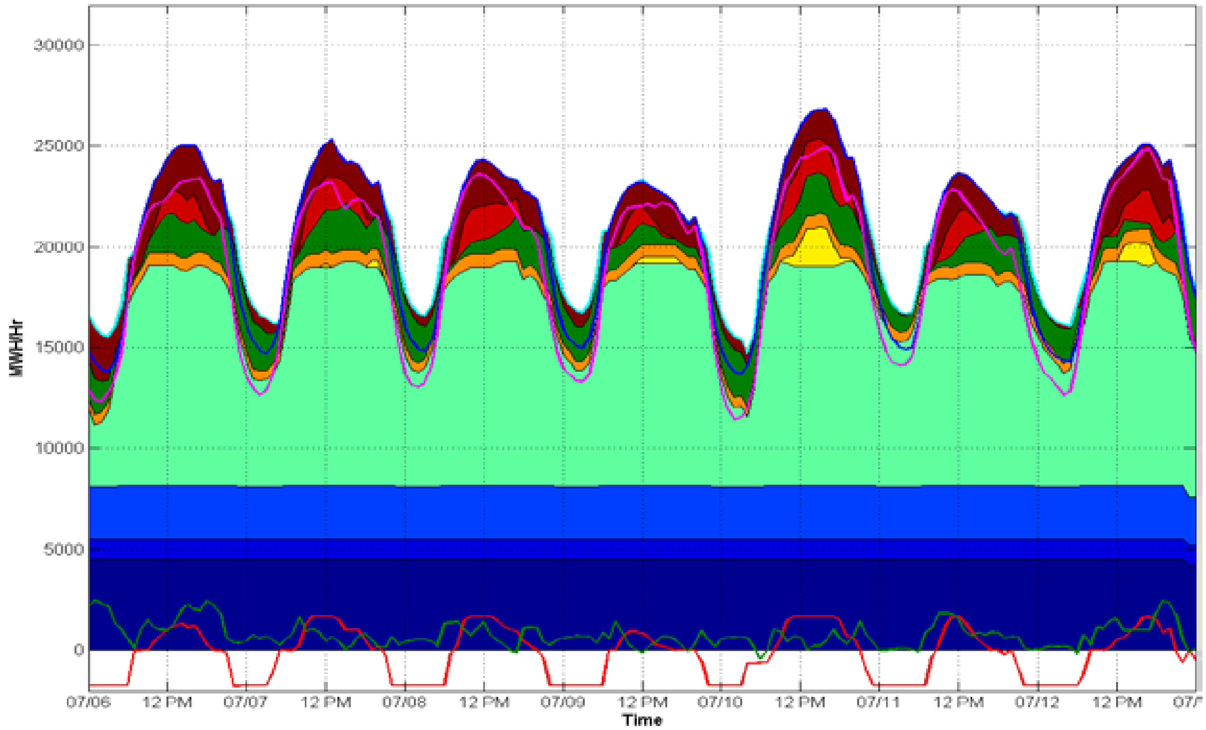


Figure 5–40 ISO-NE dispatch, week of July 6, 9% Energy, S-o-A forecast

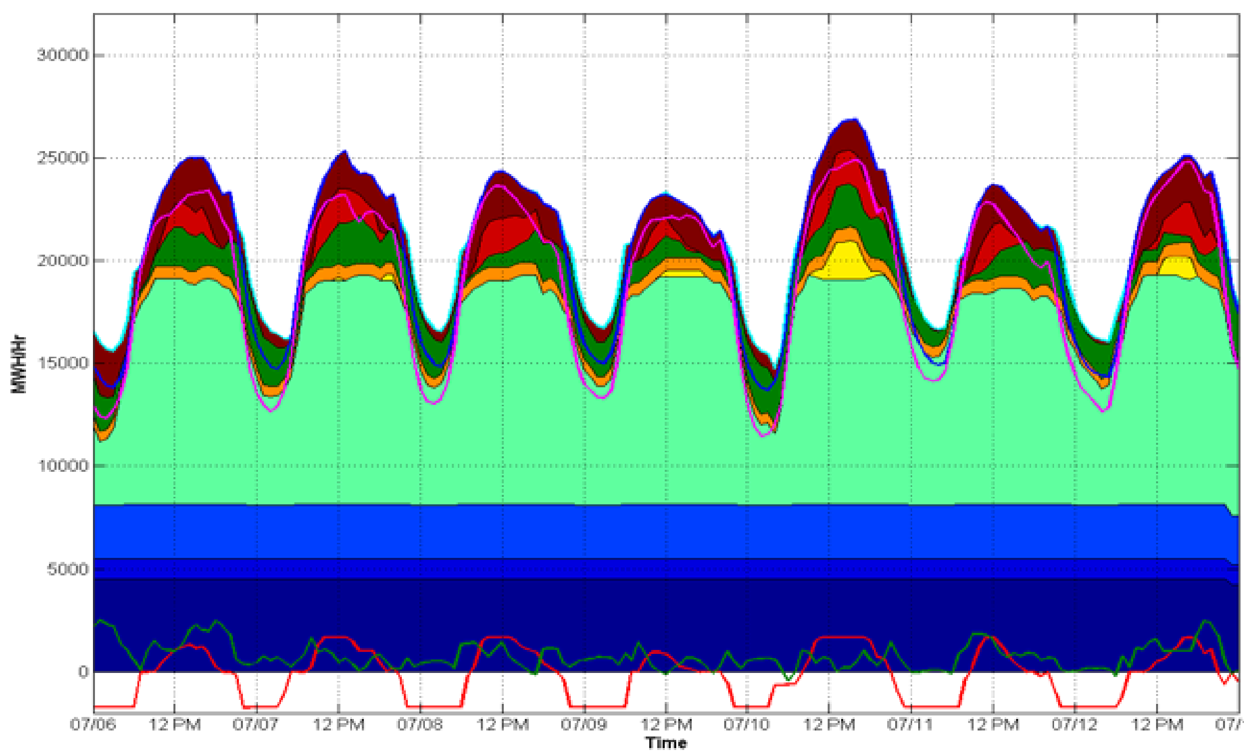


Figure 5–41 ISO-NE dispatch, week of July 6, 14% Energy_Best Sites Onshore, S-o-A forecast

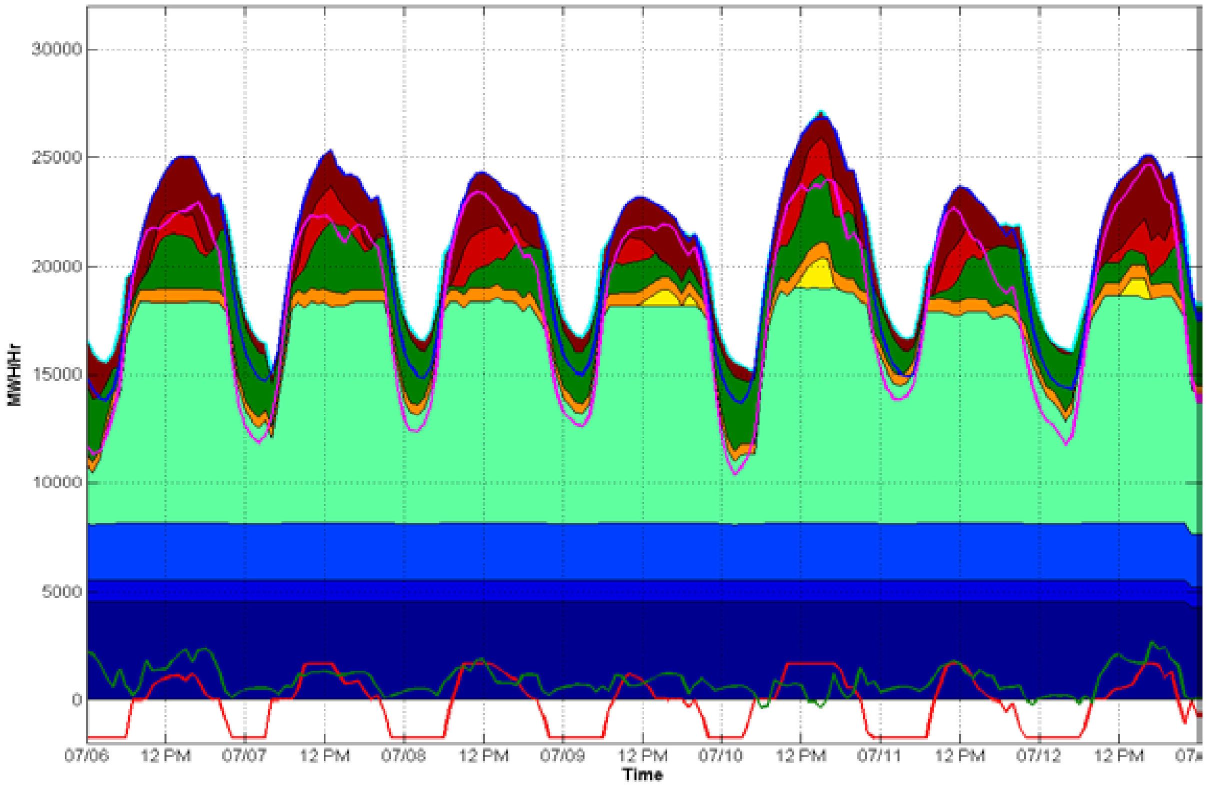


Figure 5–42 ISO-NE dispatch, week of July 6, 20% Energy_Best Sites Onshore, S-o-A forecast

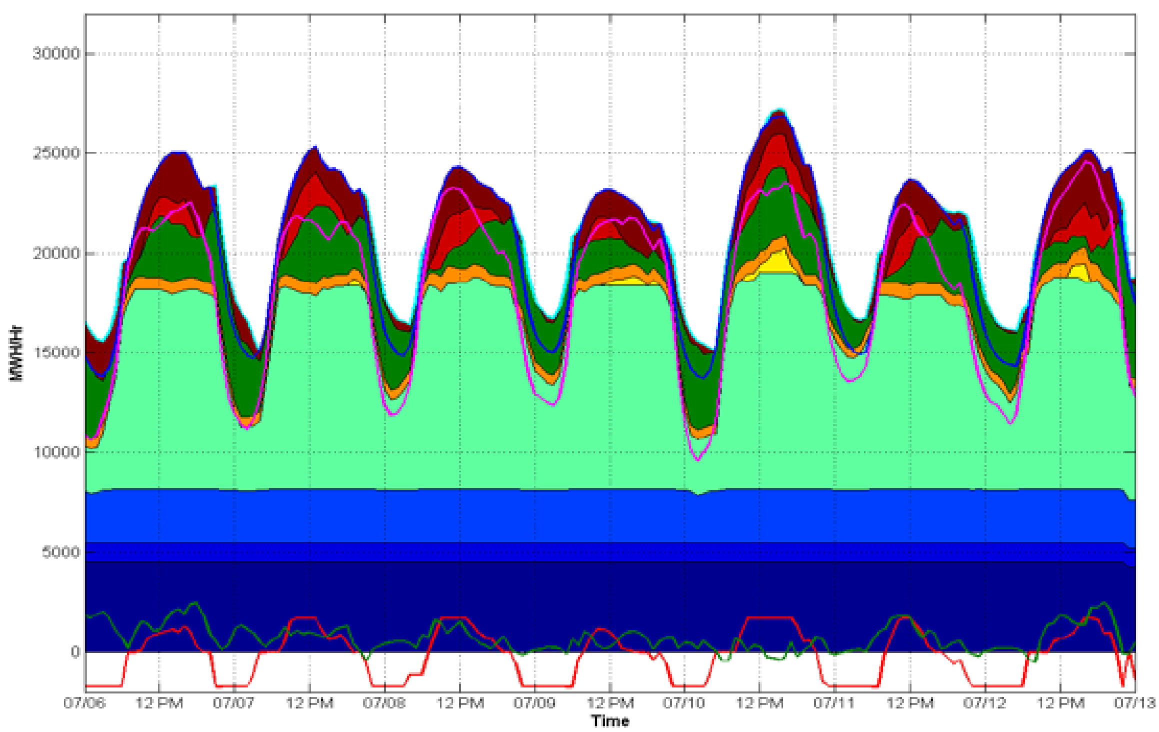


Figure 5–43 ISO-NE dispatch, week of July 6, 24% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–44 through Figure 5–47 shows the range and ramp for a week in a spring month and summer month. The hourly results are similar to the annual duration charts. They show as the wind penetration increases, the range/ramp up available capacity increases and the range /ramp down available capacity decreases. The week in July has less variability between the different penetration levels because there is less wind online.

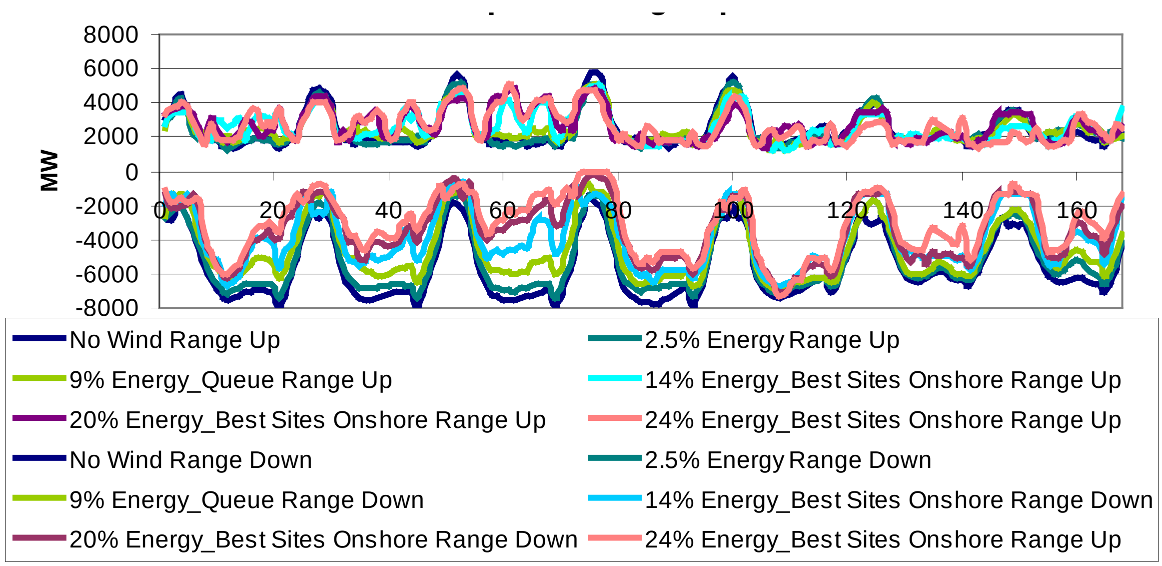


Figure 5–44 Range up/down capability week of April 13 S-o-A forecast, Best Sites Onshore

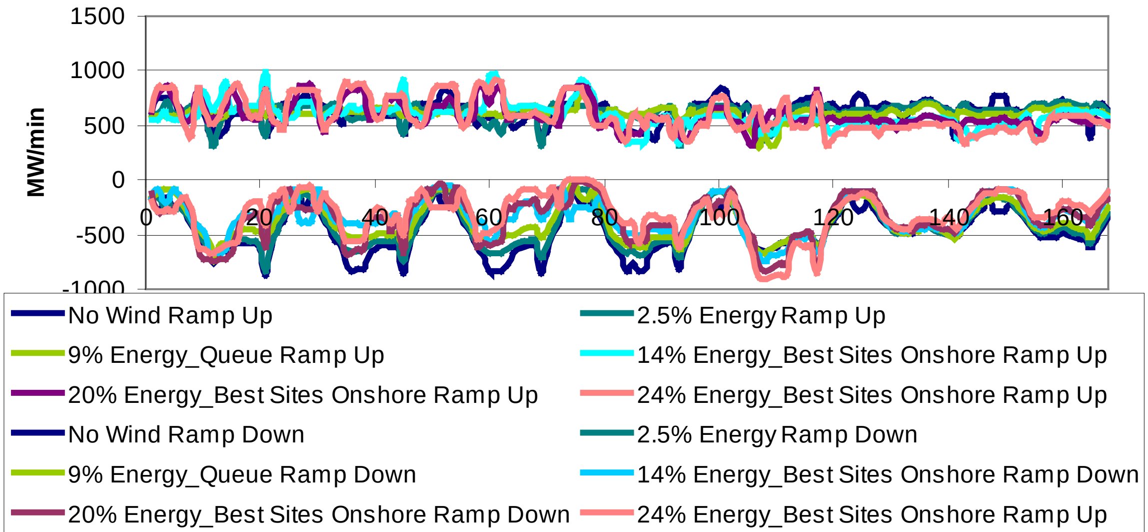


Figure 5–45 Ramp up/down capability week of April 13 S-o-A forecast, Best Sites Onshore

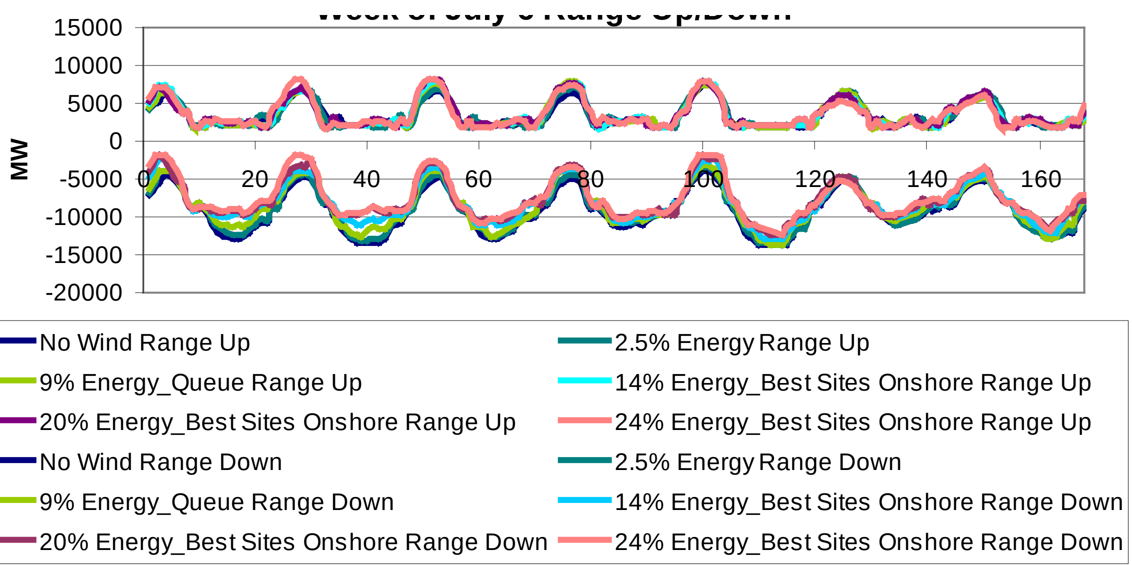


Figure 5–46 Range up/down capability week of July 6 S-o-A forecast, Best Sites Onshore

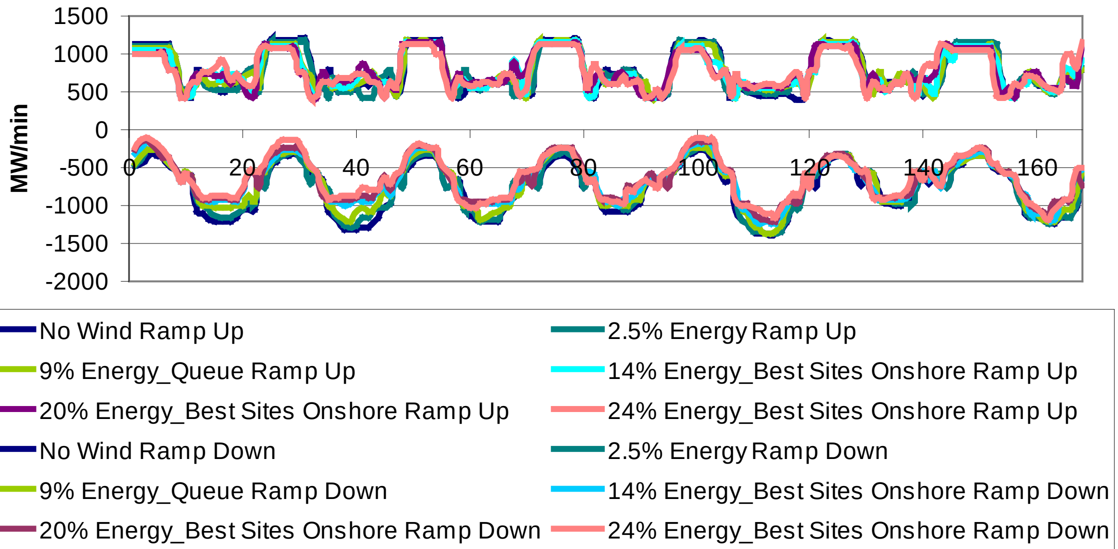


Figure 5–47 Ramp up/down capability week of July 6 S-o-A forecast, Best Sites Onshore

5.2.2 20% Wind Penetration

The following section compares the impact of 20% wind penetration on the ISO-NE system for the 5 different scenarios describes in Chapter 3. Note that the "Balance Case" is also referred to as the "Best Site" scenario. The results were done using 2006 load and wind shapes, an unbiased State-of-the-Art (S-o-A) day-ahead forecast of the wind generation and a constrained transmission system. Any variations will be noted.

Table 5–9 compares the total average three-year wind energy to the simulated wind using the 2006 shapes. There are slight differences by scenario as compared to the three-year average as well as slight differences between 2006 energy for the scenarios. These differences are minor though.

Table 5–9 20% penetration scenario comparison

Scenario	3 Year Average Wind Energy (GWh)	2006 Wind Energy (GWh)
20% Energy_Best Sites Onshore	29,060	28,882
20% Energy_Best Sites Offshore	29,060	29,494
20% Energy_Best Sites	29,060	29,222
20% Energy_Best Sites by State	29,060	29,212
20% Energy_Best Sites Maritimes	29,060	28,639

Although each of the five scenarios are made up of different sites overall, the wind pattern is similar across them. Figure 5–48 compares the wind energy by 20% scenario on a monthly basis. Although the annual energy is very similar for all the scenarios, the monthly energy has some variation. For example, in March the 20% Energy_Best Sites Maritimes has the lowest monthly energy produced, but in December it has the greatest out of the five. Although the maintenance was held constant for all the scenarios, the maintenance will interact with the wind generation. For example if a large unit is out in May, different units may be displaced in the various scenarios depending on the wind profile. Therefore depending on the load and the maintenance, each scenario will produce different results.

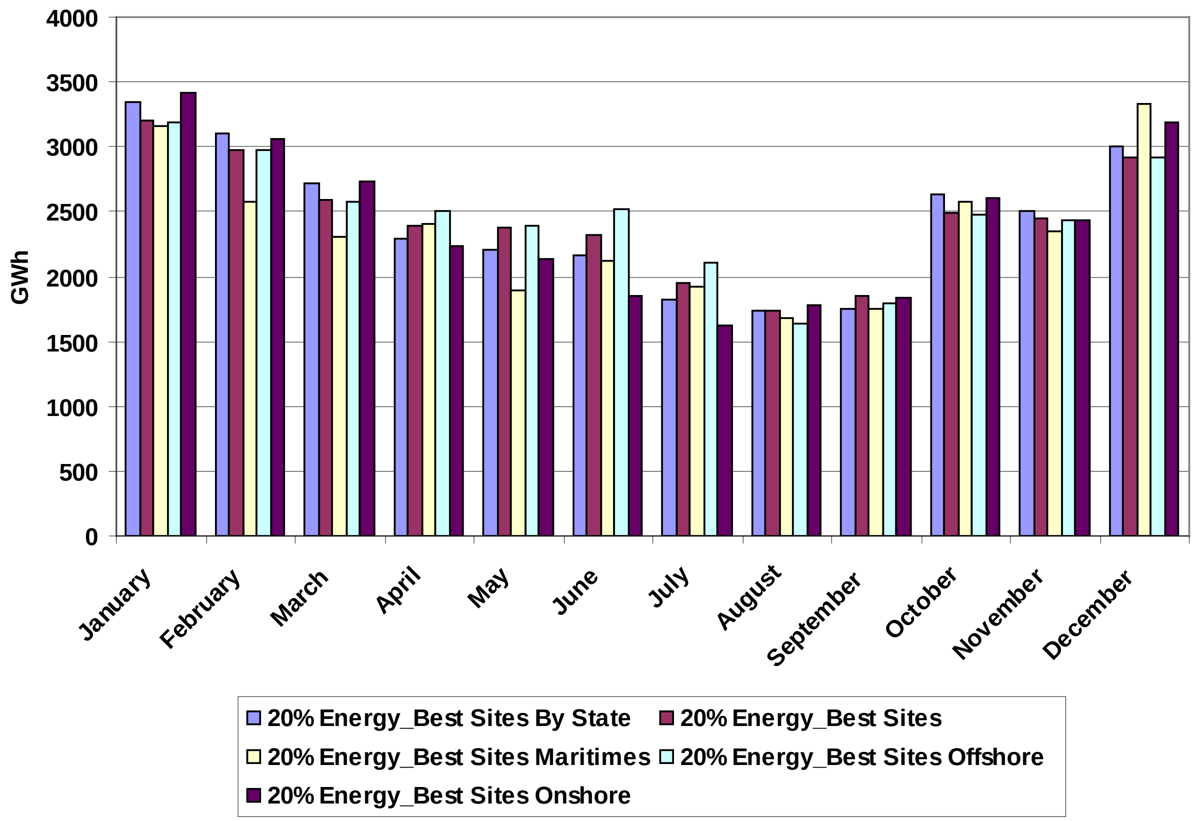
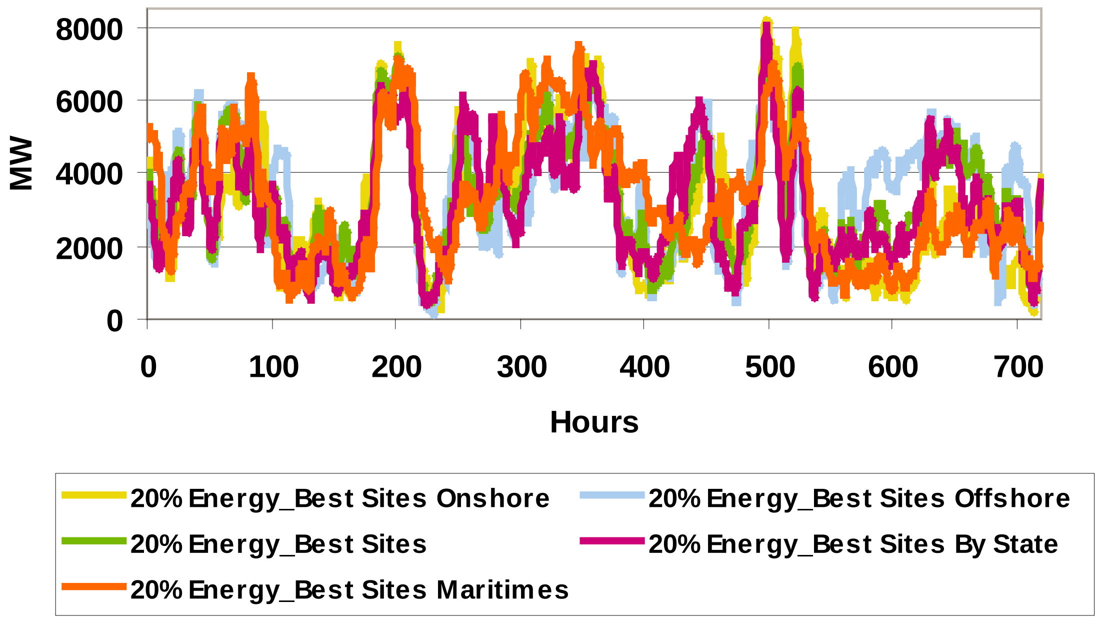


Figure 5–48 20% Scenarios Monthly Energy Summary

Figure 5–49 illustrates the hourly wind generation for the month of April and July for each of the scenarios. These months were highlighted to show a spring and summer month. Overall the shapes are similar for the scenarios.



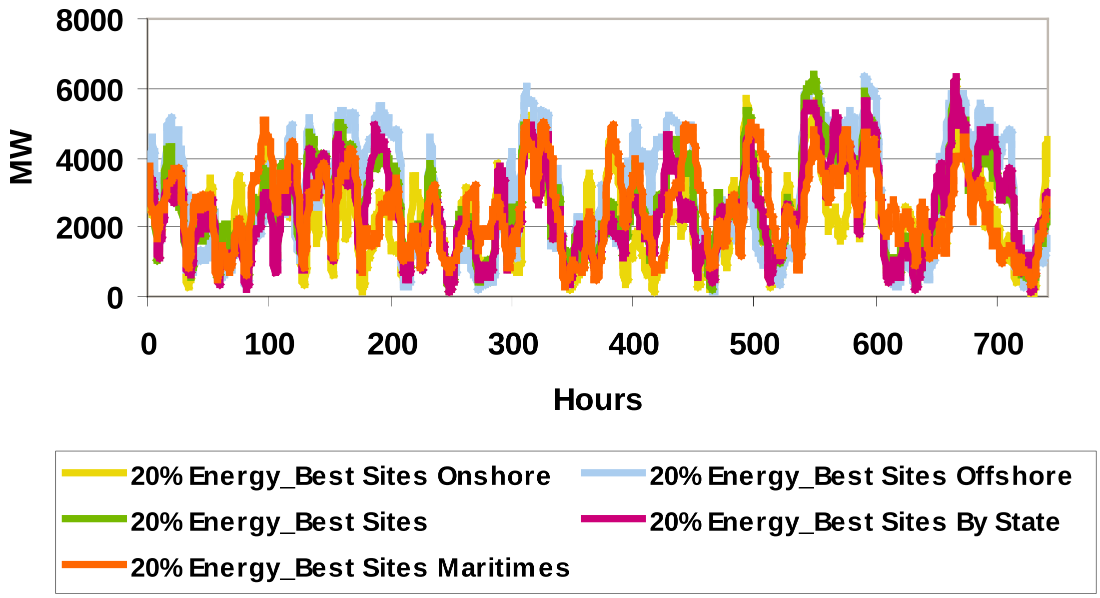


Figure 5–49 April and July hourly wind generation, 20% wind penetration

Figure 5–50 compares the annual average load weighted ISO-NE LMP for the five different constrained 20% penetration scenarios. It also includes the No Wind Scenario. The No Wind Scenario removed all wind from the modeled system. This was done for comparison purposes. It allows the overall impact of the wind penetration to be determined. The average LMP for the No Wind Scenario was approximately $61/MWh. The 20% Energy_Best Sites By State had the largest reduction and the 20% Energy_Best Sites Maritimes had the smallest reduction. Overall the reduction of LMP by introducing 20% wind penetration into ISO-NE ranged from $5/MWh to $11/MWh.

The overall impact of 20% wind penetration is relatively small on the annual average LMP as compared to No wind case. Wind energy helps to reduce some high priced hours, but most of the impact is during the off peak times. During these hours gas is on the margin and is displaced by the wind. The wind does not cause a large shift from gas to coal, which will be shown later in this chapter, leaving gas still on the margin. This has a small impact on the LMP.

There are slight variations between the different scenarios. Overall the location of the wind has a small impact on the overall result.

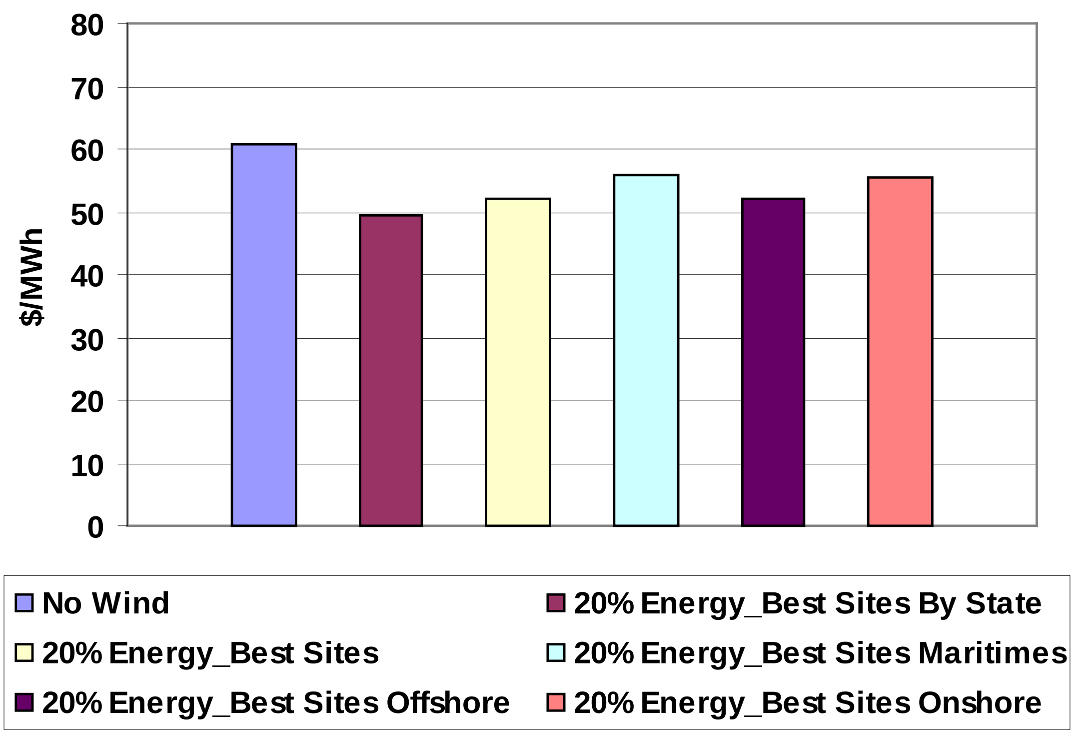


Figure 5–50 Annual load weighted average ISO-NE locational marginal price, S-o-A Forecast, 20% penetration

Figure 5–51 shows the RSP zonal load weighted annual average LMP. There is some slight variation in the No Wind Scenario. The prices are relatively flat across the RSP zones for each of the 20% scenarios. This indicates that the Governors' 4 GW overlay is sufficiently built to eliminate transmission congestion and handle 20% penetration of wind. More details will be presented on the impacts of transmission later in this section.

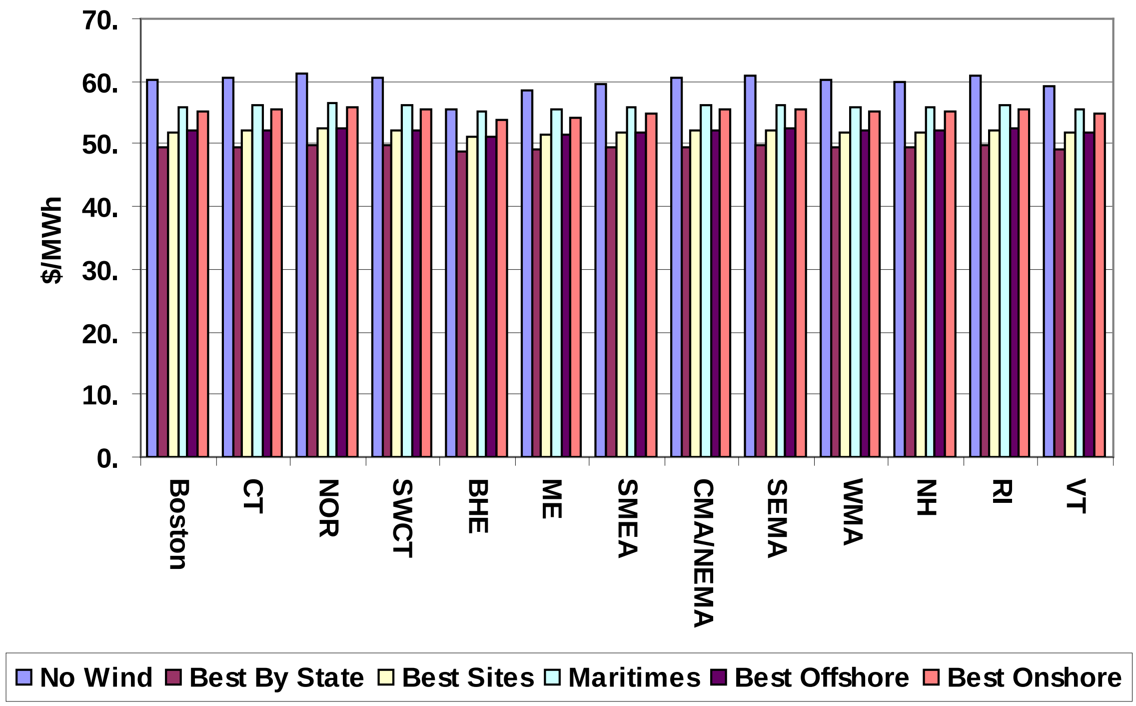


Figure 5–51 Annual load weighted average ISO-NE RSP locational marginal price, S-o-A Forecast, 20% penetration

Figure 5–52 shows No Wind and 20% Energy_Best Sites Onshore scenarios RSP zonal load weighted annual average LMP. The zonal price variations can be seen more clearly. There are some slight variations in the 20% Energy_Best Sites Onshore scenarios, but the magnitude is much smaller than the No Wind scenario. This occurs because the transmission system is expanded from the ISO-NE 2019 system in the No wind Scenario to the Governors' 4 GW overlay in the 20% Energy scenarios, reducing transmission congestion between RSP zones.

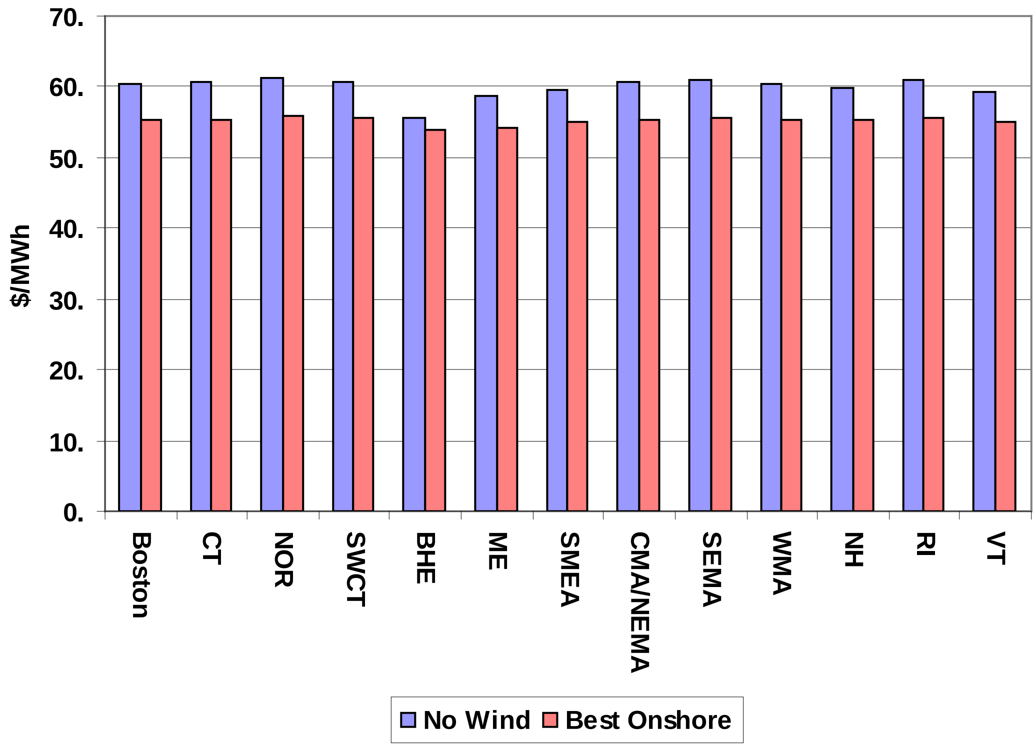


Figure 5–52 Annual load weighted average ISO-NE RSP locational marginal price, S-o-A Forecast, 20% penetration No wind, Best Onshore

Figure 5–53 shows the hourly duration LMP that corresponds to Figure 5–50. These were calculated chronologically for each hour of the year for each scenario. They were then sorted for easy comparison of the overall impacts. The first plot is for the full 8784 hours of the year. The following plots zoom in on the highest/lowest 1000 hours.

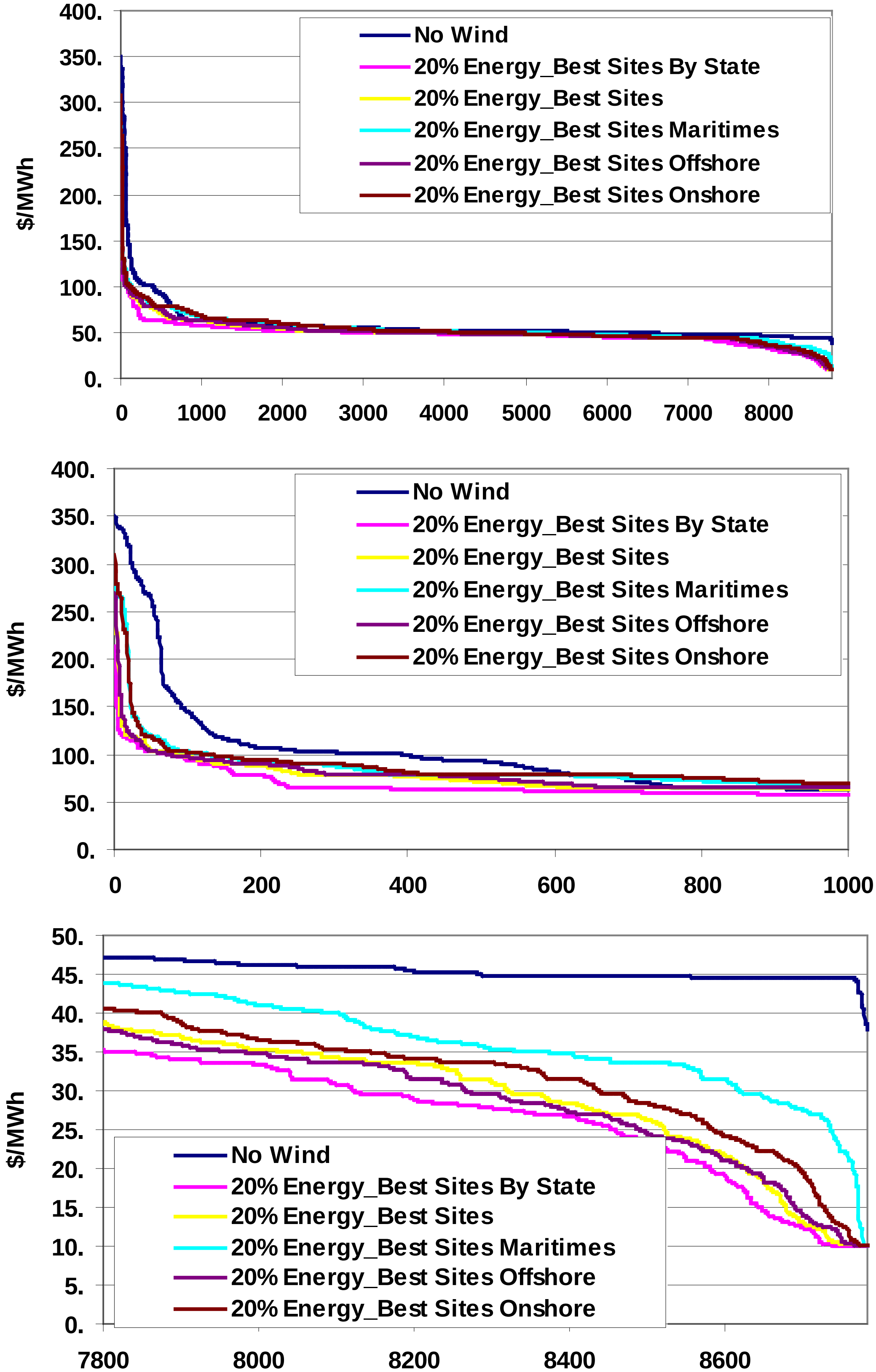


Figure 5–53 Annual LMP duration curve, S-O-A Forecast, 20% penetration

With no wind generation on the system, the LMP ranges from a high of approximately $350/MWh to a low of about $38/MWh. All of the 20% penetration scenarios have similar impacts on the spot price. Introducing 20% penetration of wind to the system reduces the highest cost to about $300/MWh and the lowest to about $10/MWh. As described in section 5.2.1, the $10/MWh price is based on the wind dispatch cost during these hours; the wind was curtailed to not allow it to displace nuclear generation. This would be classified as minimum generation events. The most this occurs is 34 hours. This equates to approximately 0.4% of the year. As mentioned earlier in the chapter, negative bids were not modeled and therefore the LMP never goes negative.

Curtailment can be caused by mainly three issues: transmission congestion, minimum generation events where nuclear is on the margin, and minimum generation events due to the under forecasting of wind. Under forecasting can lead to excess thermal generation being committed which can lead to minimum operating constraints. A discussion on the forecast error by penetration and scenario can be found in Chapter 3. Table 5–10 summarizes the total curtailment for the 20% Energy scenarios. It also shows the percentage of curtailed wind to the total wind energy for the scenario. The curtailment is relatively low. The 20% Energy Best Sites Offshore had the smallest amount of curtailment.

Table 5–10 Wind Curtailment 20% Energy

Scenario	Curtailment (GWh)	% Total Energy
20% Energy_Best Sites Onshore	27.12	0.09%
20% Energy_Best Sites Offshore	16.23	0.06%
20% Energy_Best Sites	29.55	0.10%
20% Energy_Best Sites by State	60.33	0.21%
20% Energy_Best Sites Maritimes	328.65	1.15%

AS can be seen in the table the 20% Energy Best Sites Maritimes had the most curtailment. 1.15% of the total wind energy for the scenario was curtailed. There were roughly 4.8 GWs of wind added to the Maritimes in addition to the full queue. The transmission system in the Governors' 4 GW overlay included the addition of a 1,500 MW HVDC cable from the Maritimes to the ISO-NE. This expanded the import capability into ISO-NE to about 3000 MW including the new connections to Northern Maine. Therefore, when the wind production was higher than this it would be used to displace Maritimes units or be curtailed.

Figure 5–54 shows the total generation by type for ISO-NE for the 20% penetration scenarios. The bulk of the energy that is displaced by the wind generation as compared to the No Wind Scenario is coming from CC units with some slight variations in GT, PSH, and St-Coal units. There are also slight variations in imports from HQ imports and Imp_Exp. One thing to note is that the wind that is imported from the Maritimes in the 20% Energy_Best Sites Maritimes is not included in the Imp_Exp. This energy is included the Wind category.

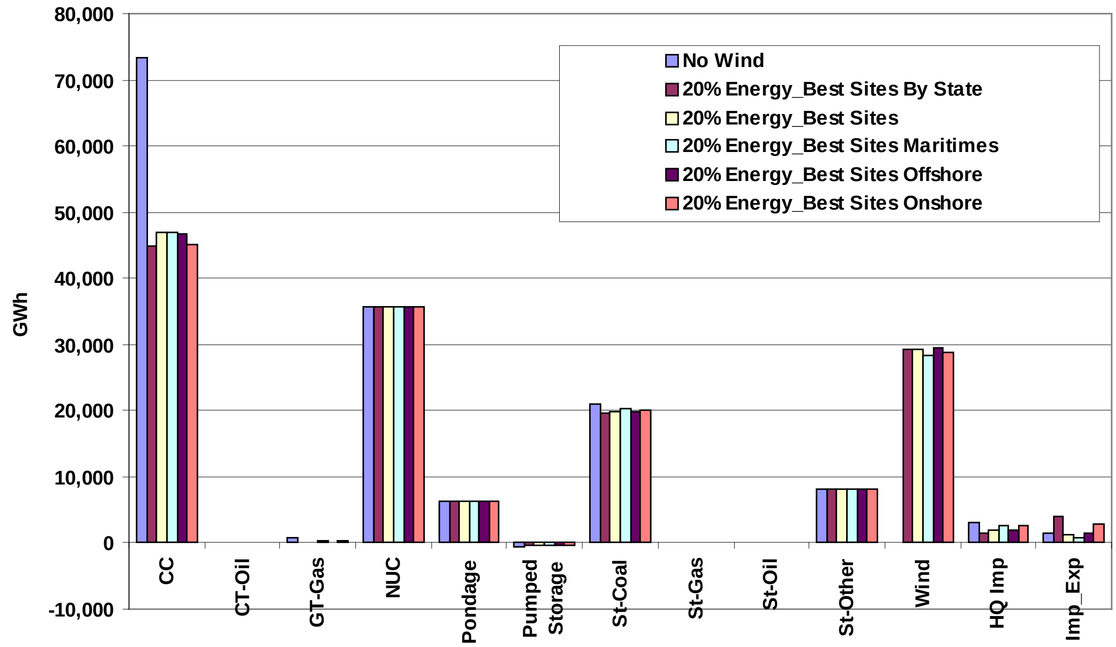


Figure 5–54 ISO-NE generation by type, S-o-A forecast, 20% penetration

It is not a surprise that most of the displacement is in CC generation for ISO-NE. Figure 5–55 is a dispatch stack, for ISO-NE system, for the year 2020. A dispatch stack, stacks the generator's calculated full load variable cost (Fuel Cost, Variable O&M, Start up Cost, Emission Cost) on a $/MWh basis from the lowest cost generation to the highest cost. The stack assumes 100% of the conventional generation is available. This provides a simple way to determine what type of generator would be on the margin depending on various load levels. The blue lines represent peak, median, and minimum load only values for 2020. The orange lines represent the net load values. The median and net median load occurs in the CC range. As can be seen in the figure, CCs would be on the margin most hours.

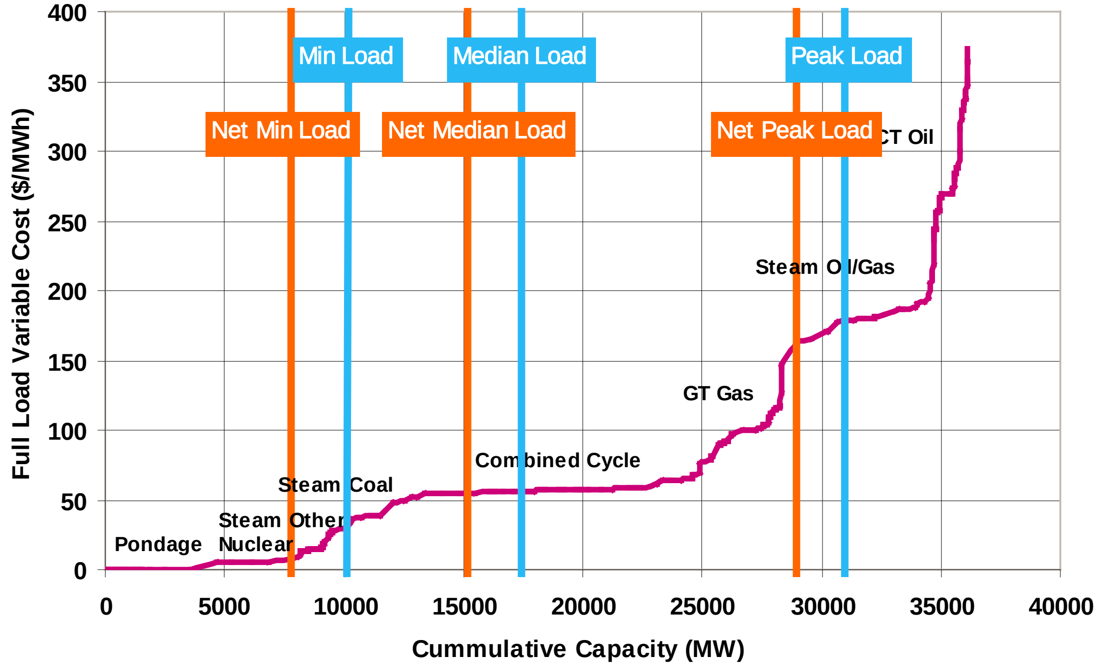


Figure 5–55 2020 ISO-NE dispatch stack

Figure 5–56 shows the hourly duration curve for the pumped storage hydro operation in ISO-NE for the No Wind and the five 20% wind penetration scenarios.

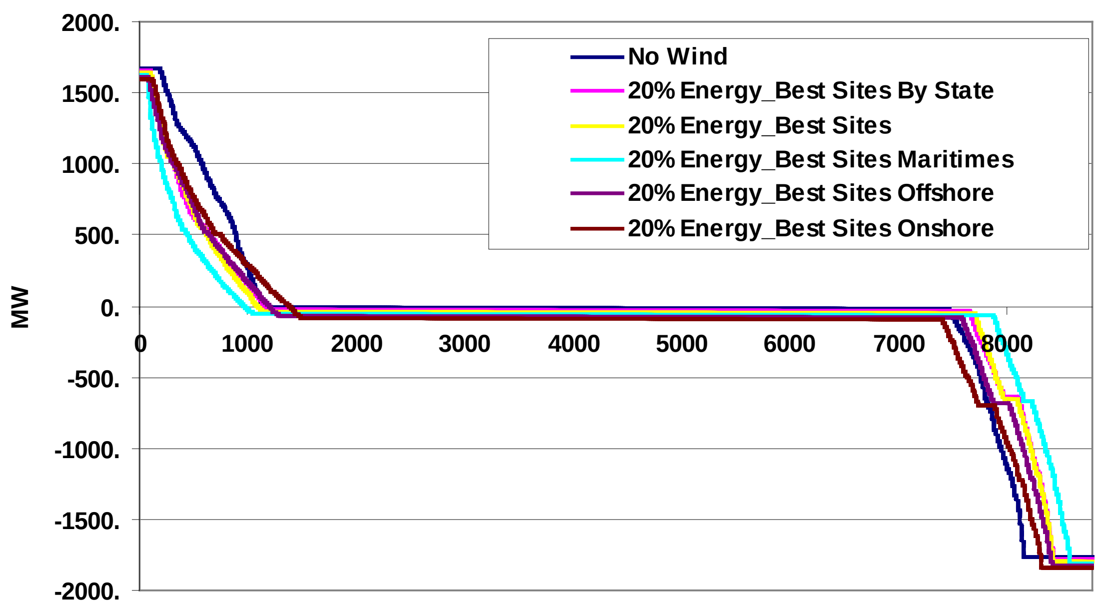


Figure 5–56 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, 20% penetration

With increased wind penetration, many believe more storage will be needed. It is important to look at how the existing storage changes with increased wind penetration. As can be seen in the figure, the operation is similar for the different wind penetration scenarios and does not vary much from the No Wind Scenario. As described in the previous section, gas is on the margin most hours even with the addition of wind generation, therefore only resulting in a large enough on-peak/off-peak price differential to warrant small changes in PSH operation.

Figure 5–57 shows the total emission for the 20% penetration scenarios as compared to the No Wind Scenario and Figure 5–58 shows the reduction relative to the No Wind scenario. The reduction is similar for all the 20% scenarios.

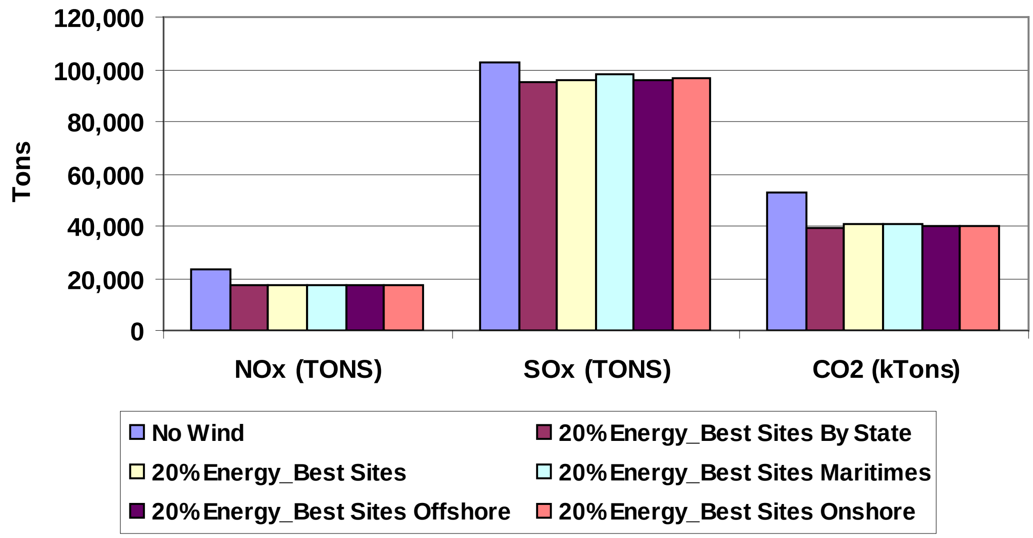


Figure 5–57 ISO-NE Total Emissions, S-o-A forecast, 20% penetration

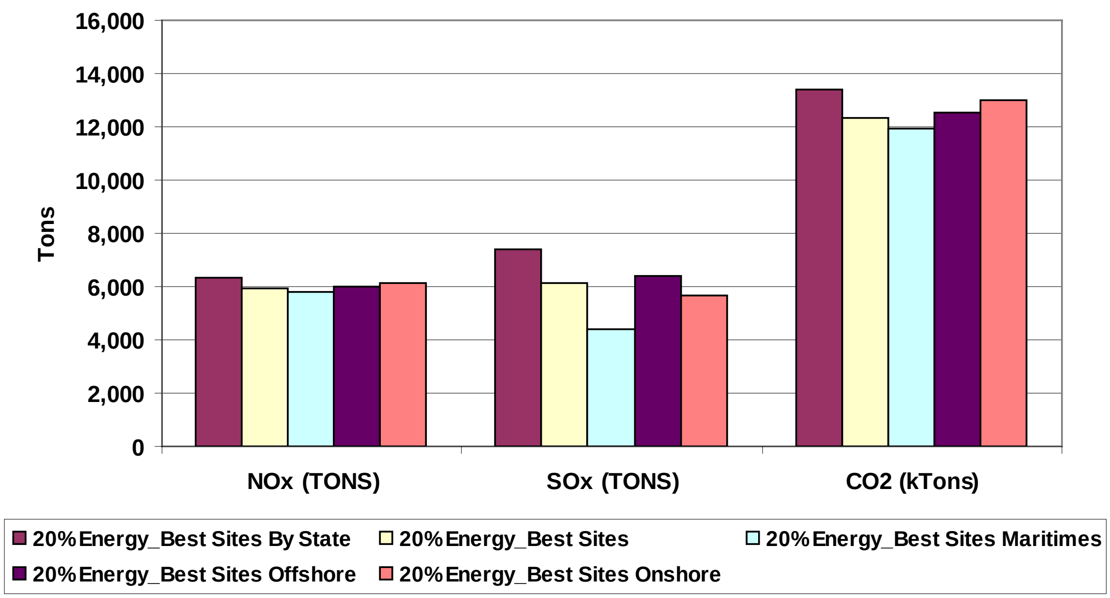


Figure 5–58 ISO-NE Total emissions reduction, S-o-A forecast, 20% penetration

The average reduction 20% wind penetration was approximately: NOx 6,000 tons or 26%, SOx 6,000 tons or 6%, and CO2 was reduced by 13million tons or 25%. The 25% reduction in CO2 with 20% wind penetration results from the fact that roughly 65% of the ISO-NE generation produces CO2. 25% of the generation that produces CO2 is being displaced.

There are slight variations in the reduction for the different scenarios. For example, the SOx reduction is the smallest in the 20% Energy_Best By Maritimes scenario. This is because the coal operation had the smallest reduction as seen in Figure 5–54.

Figure 5–59 compares the emission reduction per MWh of ISO-NE of wind generation. This was calculated for each scenario by dividing total emission reduction relative to the No Wind Scenario by the total energy produced by ISO-NE wind generation in that scenario.

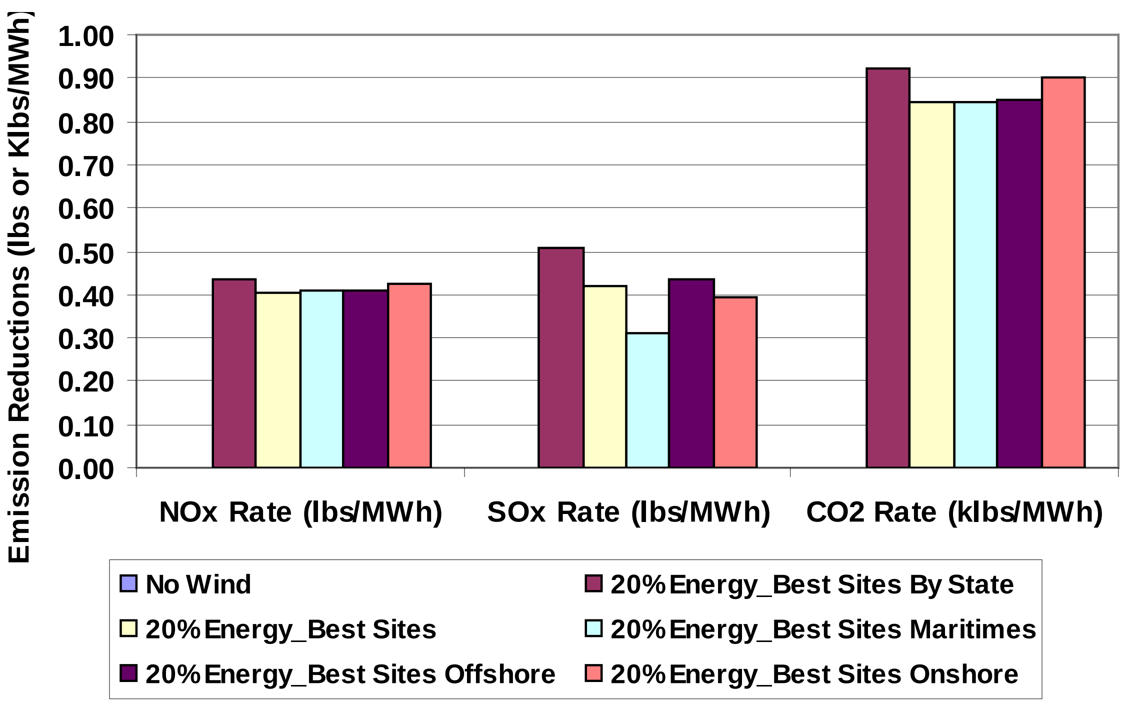


Figure 5–59 ISO-NE total emission reduction per MWh of wind generation, S-o-A forecast, 20% penetration

Figure 5–60 shows the total revenue received by each generation type. The revenue is calculated by taking the sum of the hourly LMP times the hourly generation. The revenue is reduced for all the non-wind generation. This is not only due to the lower LMP but also the displacement of generation caused by the wind energy. As expected the CC generation sees the largest reduction in revenue.

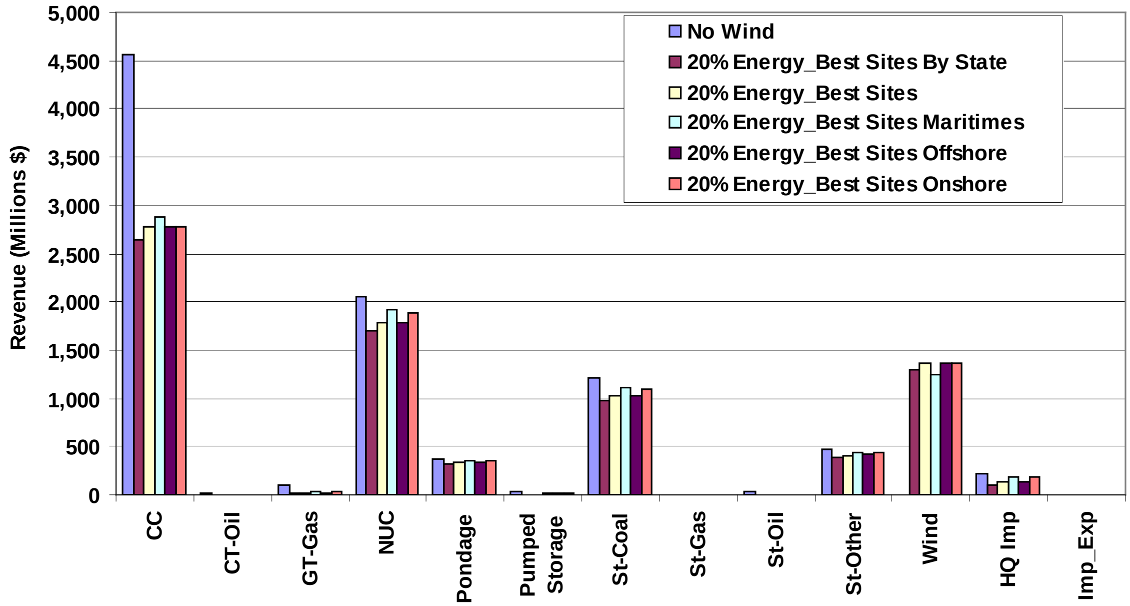


Figure 5–60 ISO-NE revenue by type, S-o-A forecast, 20% penetration

Figure 5–61 looks at the revenue and operating cost reduction per MWh of wind relative to the No Wind Scenario for CC and St-Coal generation. The operating cost reduction is a result of less operation due to the wind penetration and the revenue reduction is from a combination of reduction in operation and a lower LMP. The delta between the two is the net profit reduction due to the wind. Taking a closer look at the CCs for the 20% Energy_Best Sites Onshore case, the operating cost reduction was about $54/MWh and the revenue reduction was about $61/MWh. This is a net profit reduction of $7/MWh for CC’s per MWh of wind. St-Coal for the same case had net profit reduction of about $3 per MWh of wind. This is less than the CCs because ST coal had substantially less displacement than the CCs. Figure 5–62 shows the same data as Figure 5–61 except it is in % relative to the No Wind Scenario.

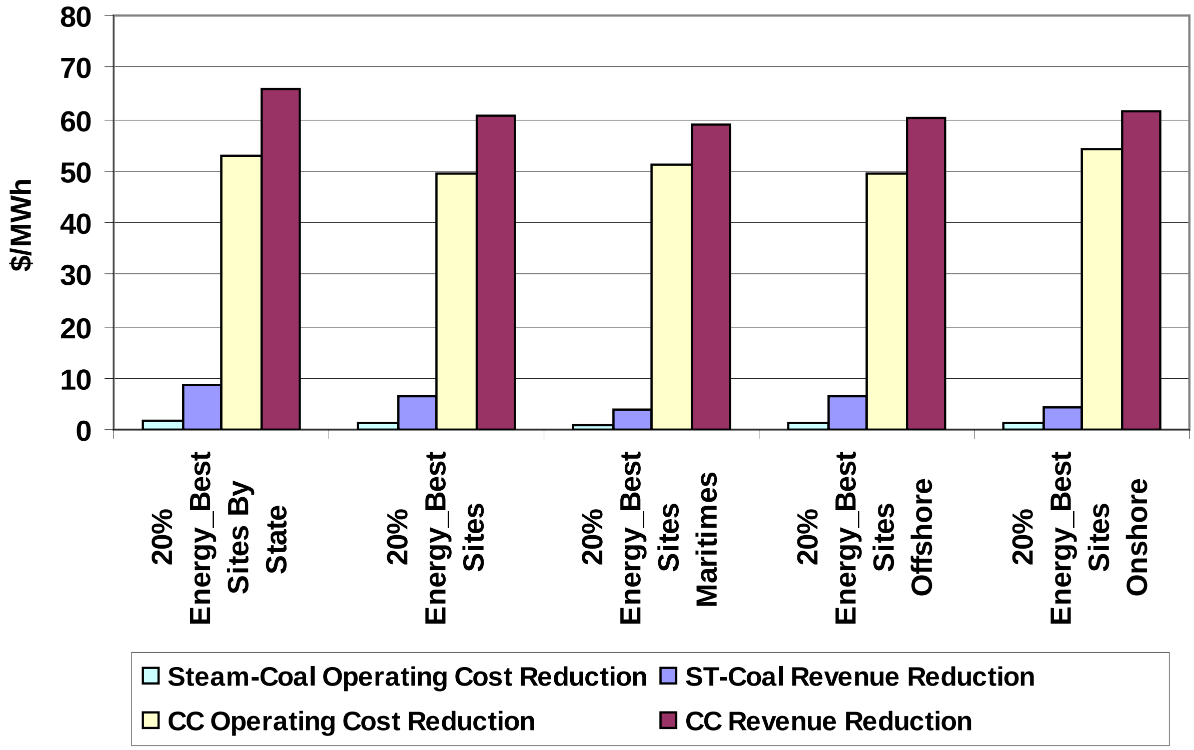


Figure 5–61 ISO-NE CC and St-Coal revenue and operating cost reduction per MWh of wind generation, S-o-A forecast, 20% penetration

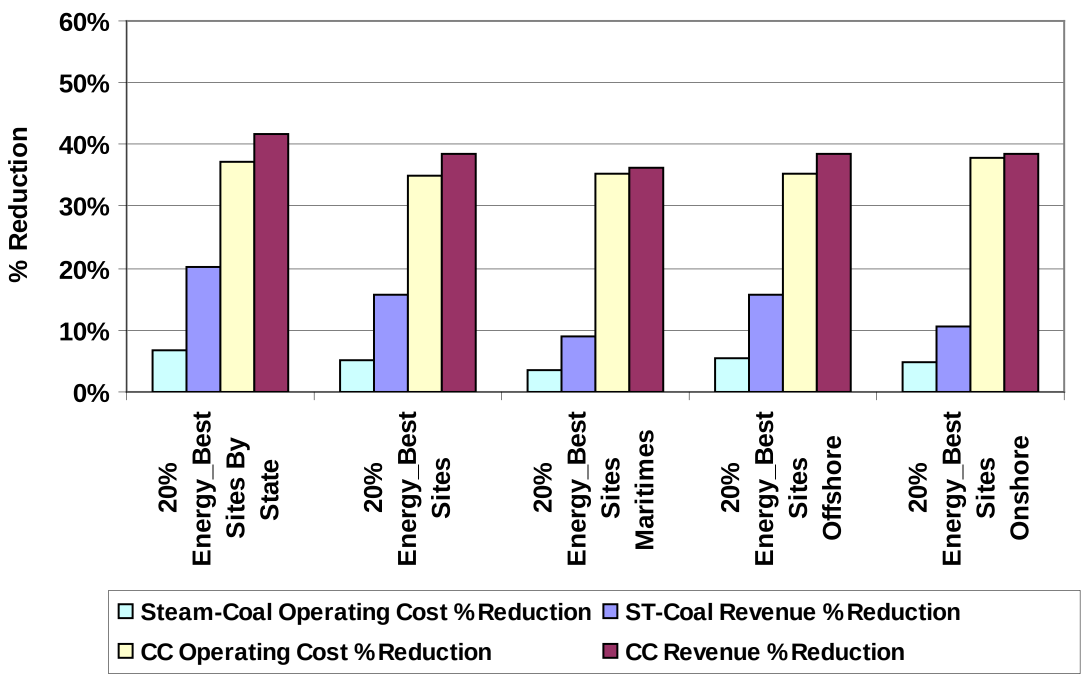


Figure 5–62 ISO-NE CC and St-Coal revenue and operating cost percent reduction per MWh of wind generation, S-o-A forecast, 20% penetration

Figure 5–63 shows the ISO-NE operational cost savings, that is, the reduction in fuel, variable O&M and startup costs from the No Wind Scenario for the various scenarios.

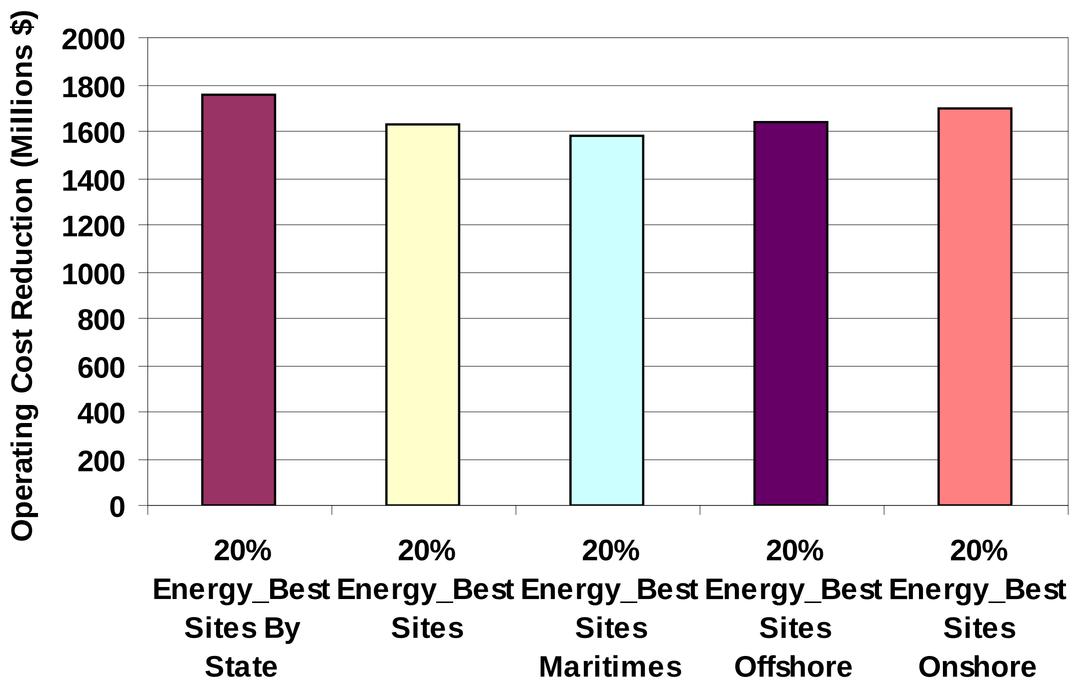


Figure 5–63 ISO-NE annual operating Cost reduction, S-o-A forecast, 20% penetration

If we divide the reduction in Figure 5–63 by the amount of net wind energy in each scenario, then we get the results shown in Figure 5–64. This shows the average value of the wind energy in each case. The value of the wind varies from $55 to $57/MWh.

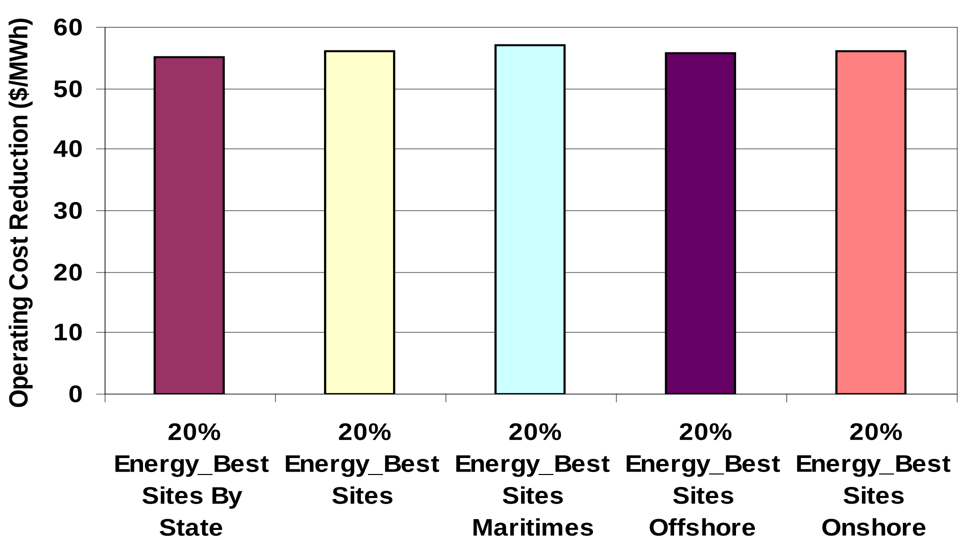


Figure 5–64 ISO-NE annual operating cost reduction per MWh of wind generation, S-o-A forecast, 20% penetration

Figure 5–65 shows the total load payments for energy for the various 20% penetration scenarios. The load payments for energy are what the Wholesale load would pay to buy energy to serve its customers. It is calculated by summing the product of the hourly load weighted LMP by the hourly demand for the year. Taking a closer look at the 20% Energy_Best Sites Onshore scenario, the load payment for energy reduction was about $750M as compared to the No Wind Scenario. 20% Energy_Best Sites By State had the largest reduction; $1.6B.

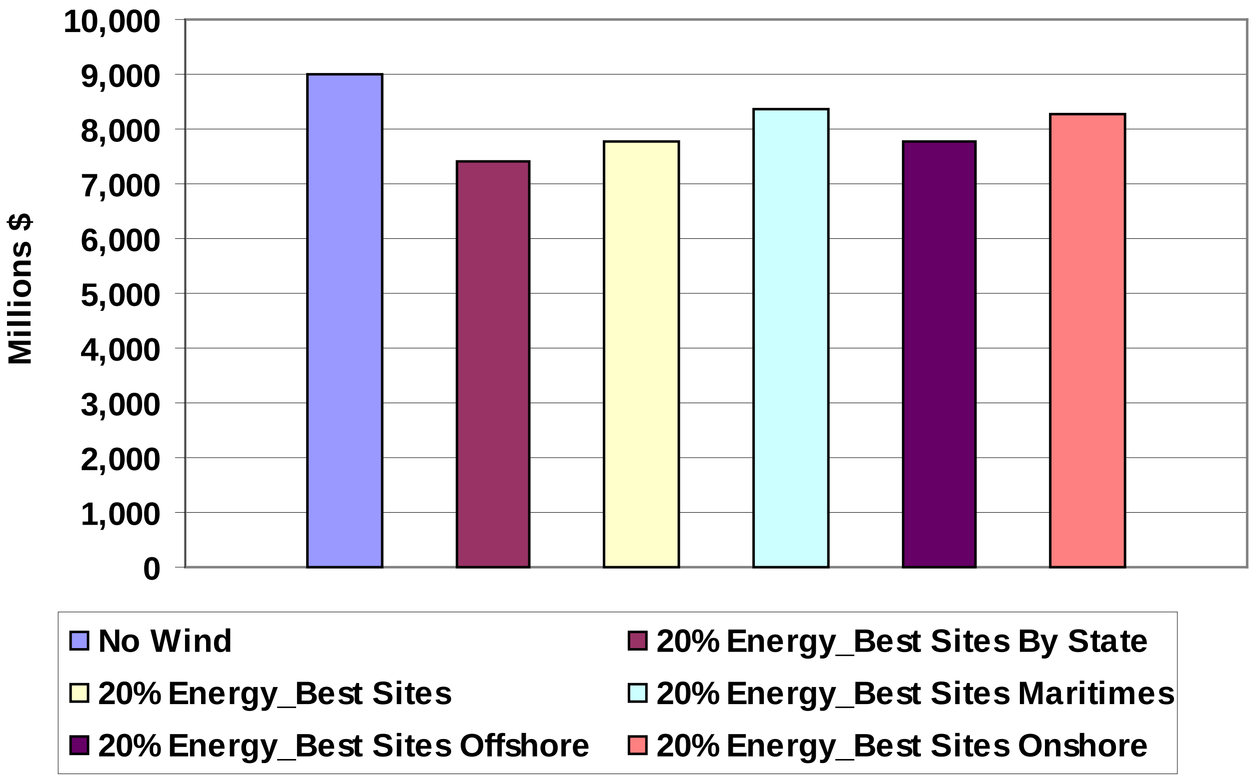


Figure 5–65 ISO-NE wholesale load payments for energy, S-o-A forecast, 20% penetration

Figure 5–66 takes the load payment for energy reduction from Figure 5–65 and divides by the total wind capacity added to ISO-NE in the 20% penetration cases. This is the benefit in load savings per kW of installed wind. The 20% Energy_Best Sites Maritimes and the 20% Energy_Best Sites Onshore have the smallest benefit per kW of installed wind. This is because they have the smallest amount of offshore wind. The offshore wind helps to reduce the LMP at times of peak more and therefore reduces the load payments for energy more.

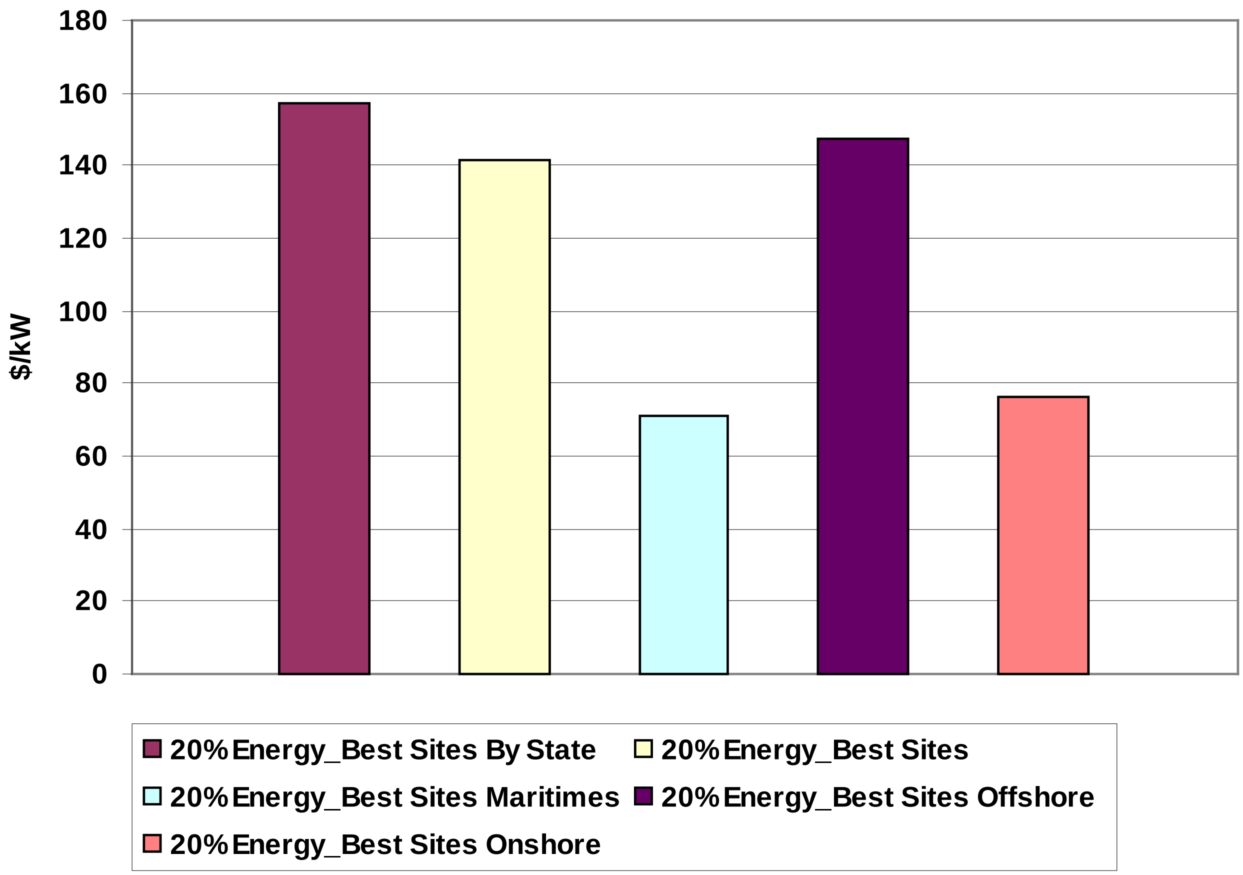


Figure 5–66 ISO-NE wholesale load payment for energy reduction per kW of wind, S-o-A forecast, 20% penetration

Figure 5–67 shows how the reduction in load payments for energy would change if a power purchase agreement (PPA) were put in place for all the wind in ISO-NE. It assumes that all the wind would be paid the same PPA rate per kWh of energy produced. The y-axis is the reduction in load payments for energy and the x-axis represents the PPA rate paid to the wind. The 20% Energy_Best Sites Onshore and 20% Energy_Best Sites By State were examined. The pink point for each curve represents the point at which the wind would be paid the average annual market price for that scenario. Taking the total revenue the wind received and dividing it by the total energy determined this point for each scenario. The market price for each scenario is between 4 to 5 cents/kWh. The point at which there would be no load payment for energy change with the addition of 20% wind penetration is at about 7 cents/kWh for the 20% Energy_Best Sites Onshore and 10 cents/kWh for the 20% Energy_Best Sites By State scenario.

One thing to note is that the load payment for energy reduction does not consider a few items. First, the wind plant revenue may be below the annual total cost of the wind plants causing the wind plant to need a higher than market value PPA. Similarly, conventional generation may need a capacity market price increase to continue to operate with the displacement from increased wind penetration. Finally, there will be cost incurred to build new transmission to get the wind to the market

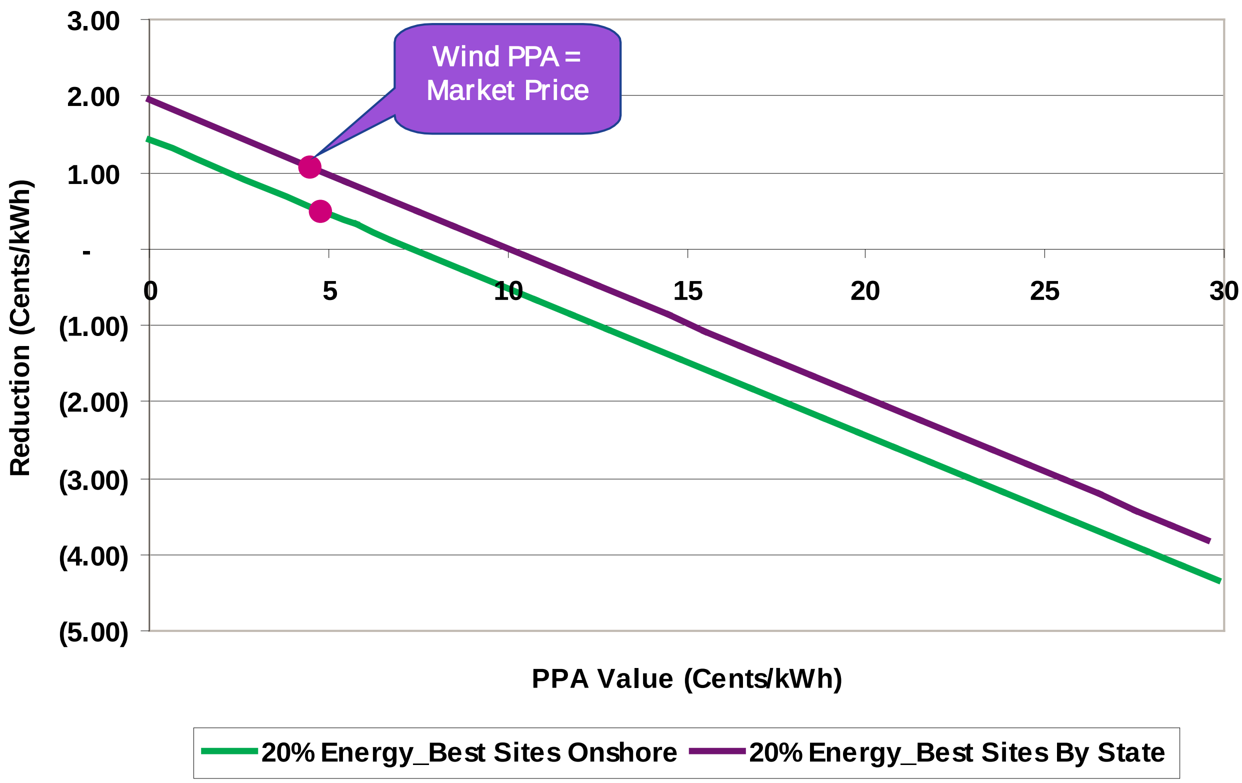


Figure 5–67 Reduction in Wholesale customer Load payments for energy PPA analysis

Although the wind scenario layouts appear very similar at the 50,000-foot level, some diversity exists between the various scenarios. For example, in comparing the operating cost reduction for the 20% Energy Best Sites by State and 20% Energy Best Sites Offshore, using a perfect and S-o-A wind forecast, the perfect forecast results in an operating cost reduction of $1,700M for the 20% Energy Best Sites by State and 1,697M for the 20% Energy Best Offshore as compared to the No Wind scenario. This is a difference of $3M between the scenarios. The S-o-A forecast resulted in a $1,760M reduction for the 20% Energy Best Sites by State and $1,643M reduction for the 20% Energy Best Offshore scenario. This is a difference of $117M between the scenarios. By dispersing the wind throughout the ISO-NE system the forecast error had much less of an impact in the Best Sites by State scenario, than the Best Sites Offshore scenario.

5.2.2.1 Transmission Constraints

The 4 GW transmission overlay was used for the 20% scenarios. This overlay was designed appropriately in order to handle the 8 to 10 GWs of installed wind in the various 20% scenarios. There was very little transmission congestion if any seen in the scenarios. Each scenario was run with full transmission and “copper sheet.” The “copper sheet” removed all the transmission constraints within the ISO-NE system. In the 20% Energy_Best Sites Maritimes case the constraints between ISO-NE and the Maritimes were also removed. Figure 5–68 compares the operating cost reduction caused by the wind operation for the constrained and “copper sheet” case. There is only a small difference with and without transmission. For example, there is roughly a $5M difference in the 20% Energy_Best Sites Onshore scenario.

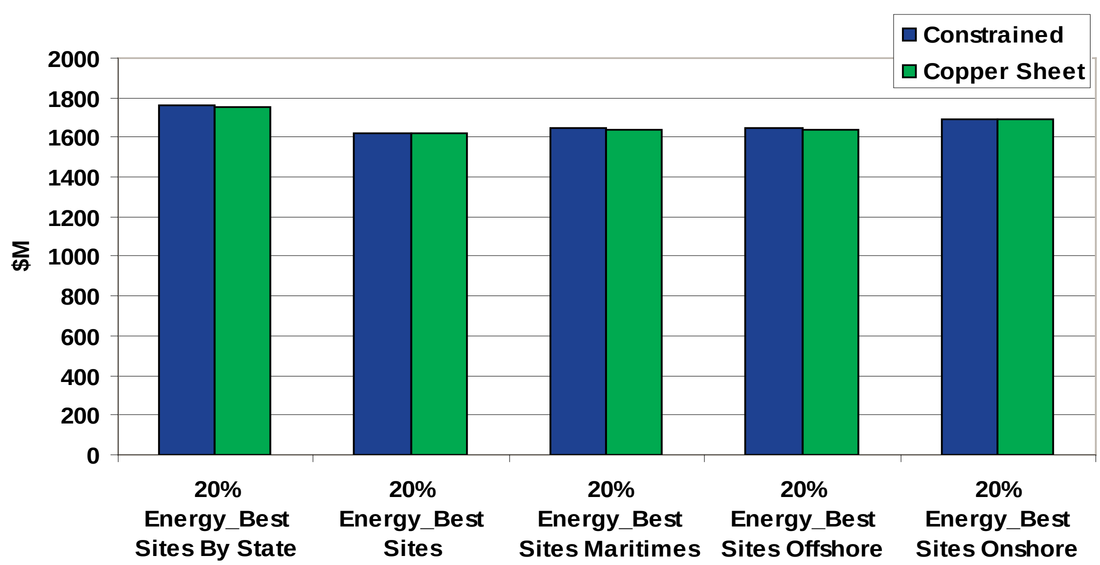


Figure 5–68 Impact of transmission constraints on ISO-NE annual Operating cost reduction, S-o-A forecast, 20% penetration

Figure 5–69 is similar to Figure 5–68 but converts the operating cost reduction to the $/MWh of wind.

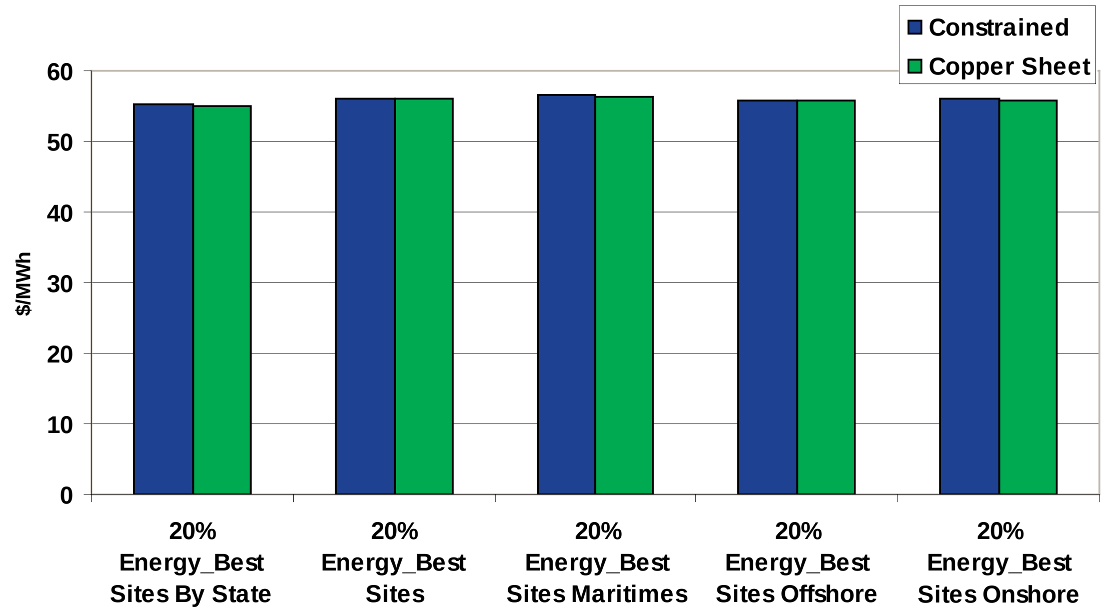


Figure 5–69 Impact of transmission constraints on ISO-NE operating cost reduction per MWh of Wind generation, S-o-A forecast, 20% penetration

Figure 5–70 is a comparison of the ISO-NE load weighted LMP with and without transmission constraints. As with the operating cost reduction, there is very little difference.

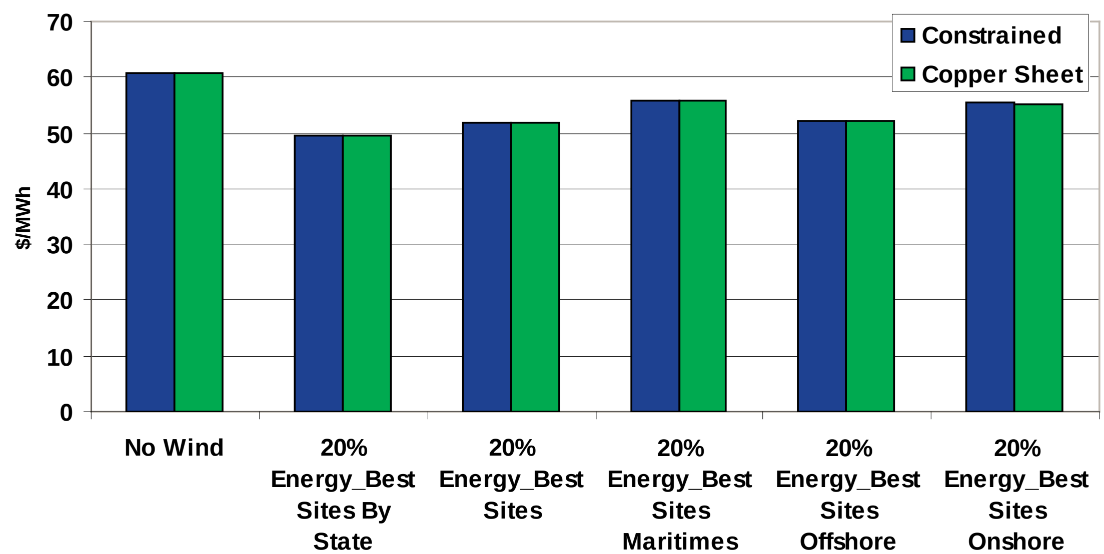


Figure 5–70 Impact of transmission constraints on ISO-NE Load Weighted Average LMP, S-o-A forecast, 20% penetration

Table 5–11 summarizes the maximum and minimum flow on each interface constraint in ISO-NE in the copper sheet case. The red highlighted cells show where the maximum flow would have been above the limit, for at least one hour, for the constrained case for the various scenarios. The column with the heading "4 GW" is the maximum and minimum limit for the interface in the constrained case.

Table 5–11 ISO-NE Copper Sheet Transmission Interface Summary, S-o-A forecast, 20% penetration

			20% Wind Penetration									
	4GW		State		Offshore		Onshore		Sites		Maritimes	
Interface	Min Rating (MW)	Max Rating (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)
North-South	-6800	6800	-331	5435	-821	5193	320	8356	240	5368	-132	6045
Boston Import	-4900	4900	658	5168	656	5019	678	5260	680	5229	665	5059
New England East-West	-7900	7900	-2674	4204	-1743	5883	-1795	5254	-1609	5439	-1744	4574
Connecticut Export	-4500	4500	-3775	1638	-3737	1259	-3923	1259	-3820	1259	-3619	896
Connecticut Import	-6600	6600	-1642	3770	-663	3754	-663	3918	-663	3815	-458	3614
Southwestern Connecticut Import	-3650	3650	234	2716	68	2554	68	2612	68	2472	162	2477
Norwalk-Stamford Import	-1650	1650	31	1478	109	1476	479	1466	110	1466	477	1412
New York-New England	-1600	1600	-1525	1600	-1600	1600	-1600	1600	-1600	1600	-1600	1600
Orrington South	-5500	5500	-444	3178	-467	3145	-206	4669	-422	3212	34	3917
Surowiec South	-5200	5200	-595	3071	-625	3272	-305	5957	-570	3984	-201	4144
Maine-New Hampshire	-5700	5700	-913	3031	-1005	3374	-438	5945	-645	3917	-322	4224
SEMA Export	-9999	9999	-1068	2154	-1025	4696	-1215	1319	-1008	2644	-1213	1400
West - East	-5100	5100	-3470	2669	-5297	1739	-4954	1791	-4853	1758	-4454	1740
NB - NE	-500	1000	-500	1000	-500	1000	-500	1000	-500	1000	-500	1000
SEMA/RI Export	-6500	6500	-1153	3779	-974	5940	-1908	2634	-1080	4359	-1846	2632

Figure 5–71 through Figure 5–76 show flow duration curves for the interfaces that were highlighted in red in Table 5–11. Orrington South was also included since historically it has been a bottleneck in ISO-NE. The flows are from the constrained case. The solid horizontal lines are the limits for the various transmission overlays used in the study. This gives a rough idea of what the impacts would be if a smaller overlay were used. For example, if the 2 GW overlay was used in the 20% Energy_Best Sites Onshore case the Orrington South would be constrained roughly 1,700 hours. Note that the 20% Energy_Best Sites Maritimes includes a 1,500 MW HVDC cable from the Maritimes to Massachusetts.

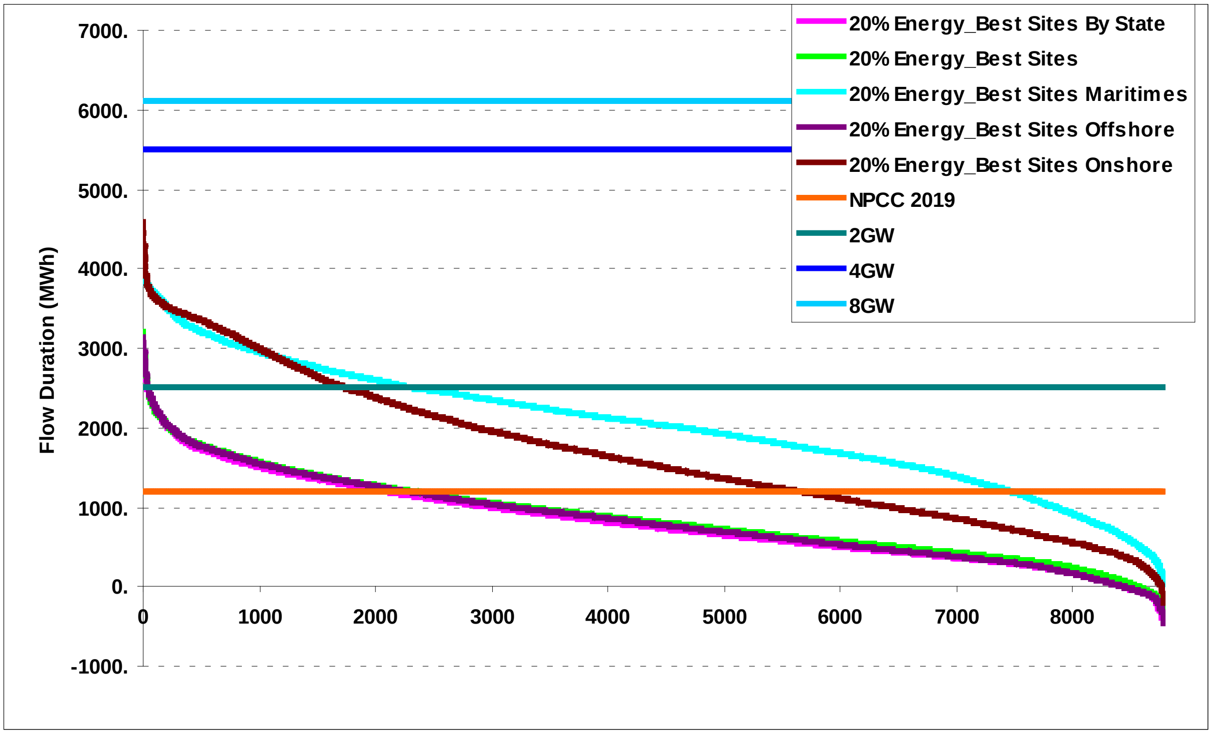


Figure 5–71 Orrington South interface flow, S-o-A forecast, 20% penetration

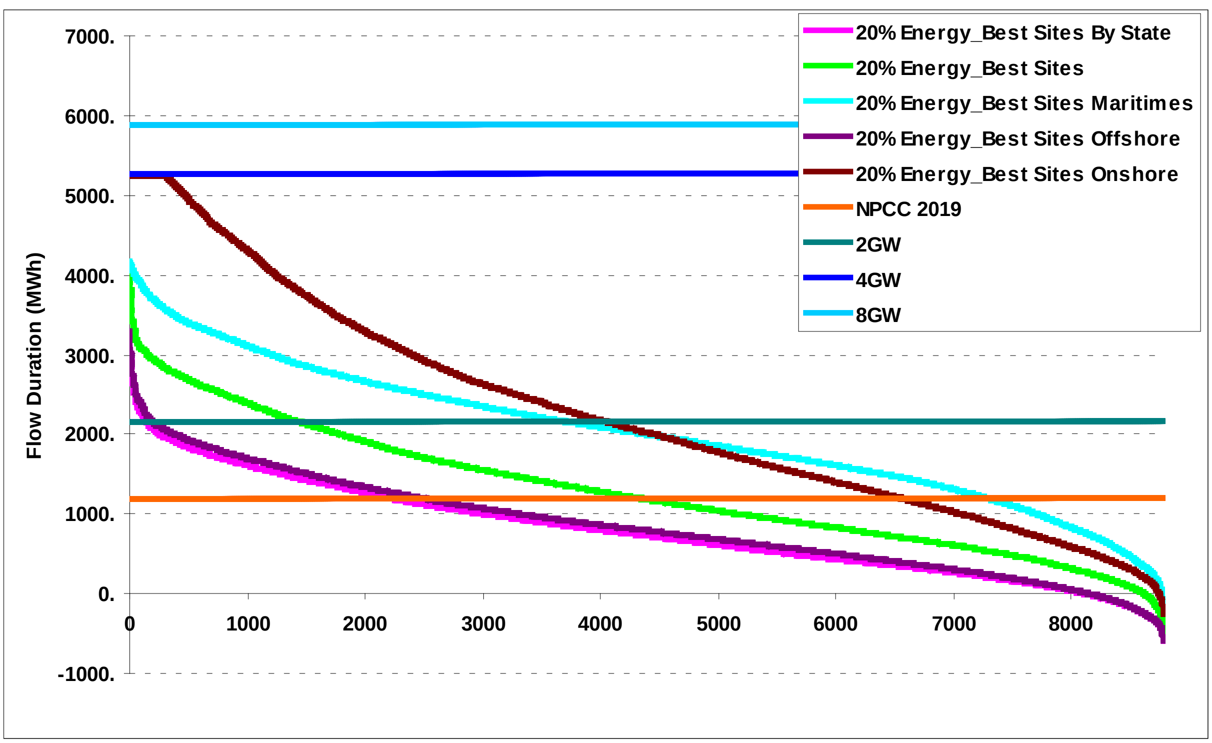


Figure 5–72 Surowiec South interface flow, S-o-A forecast, 20% penetration

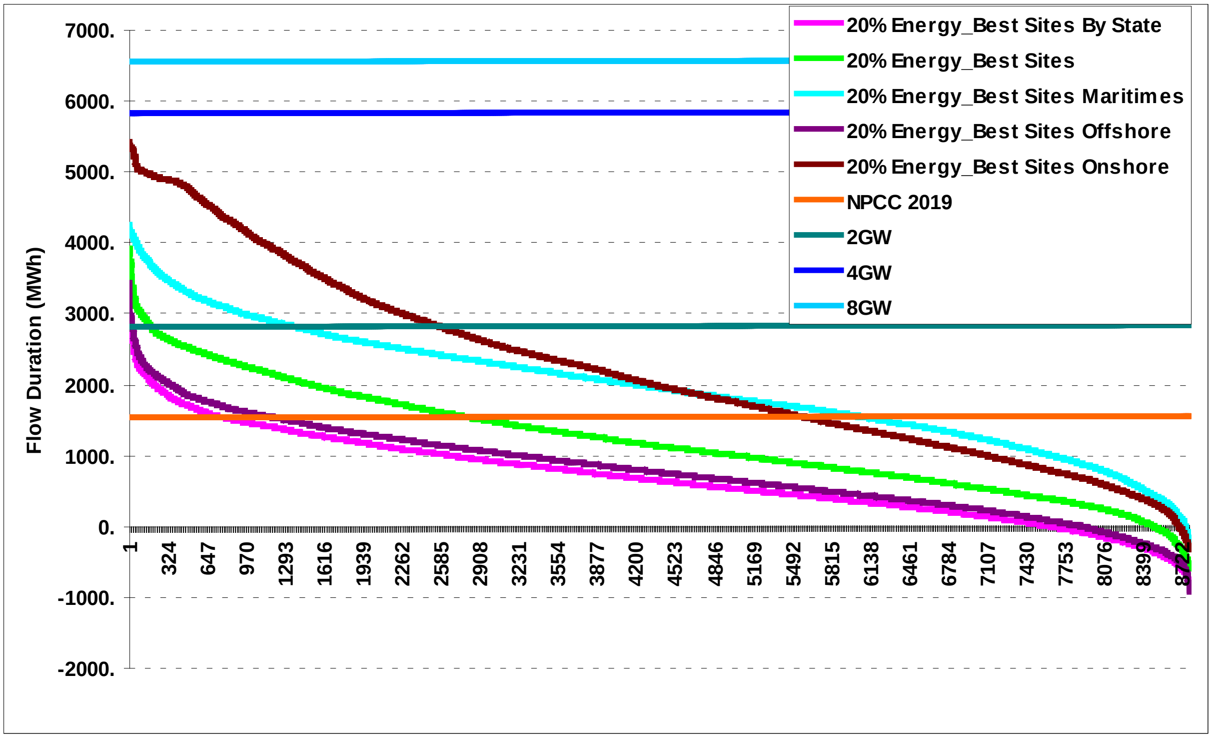


Figure 5–73 Maine/New Hampshire interface flow, S-o-A forecast, 20% penetration

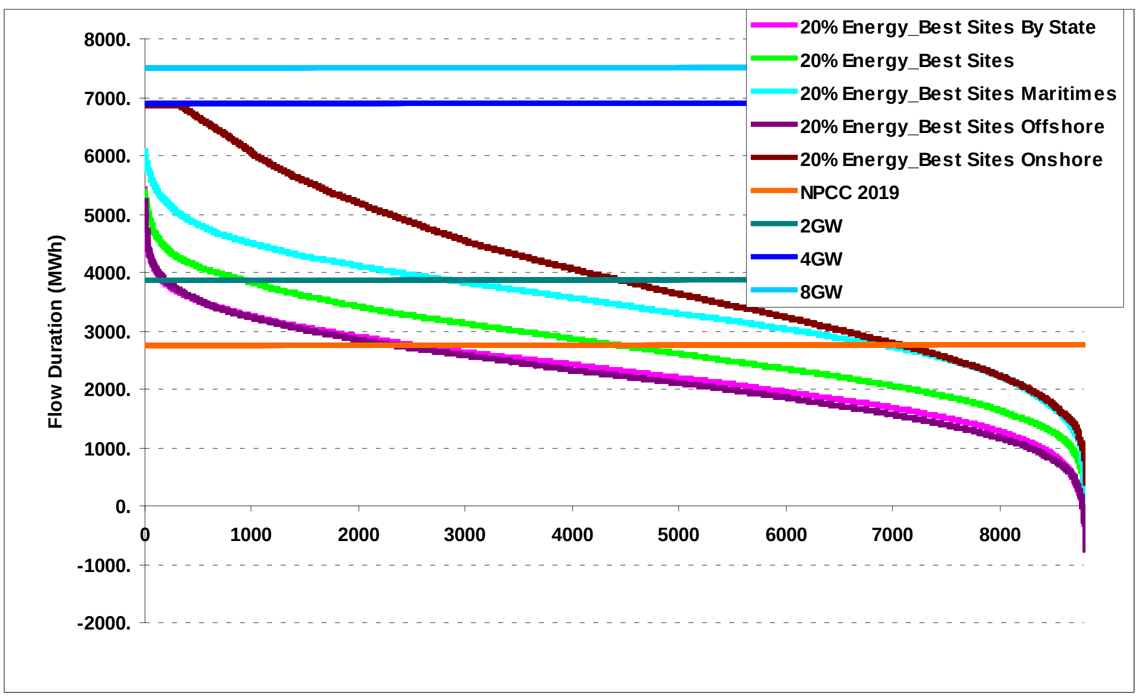


Figure 5–74 North /South interface flow, S-o-A forecast, 20% penetration

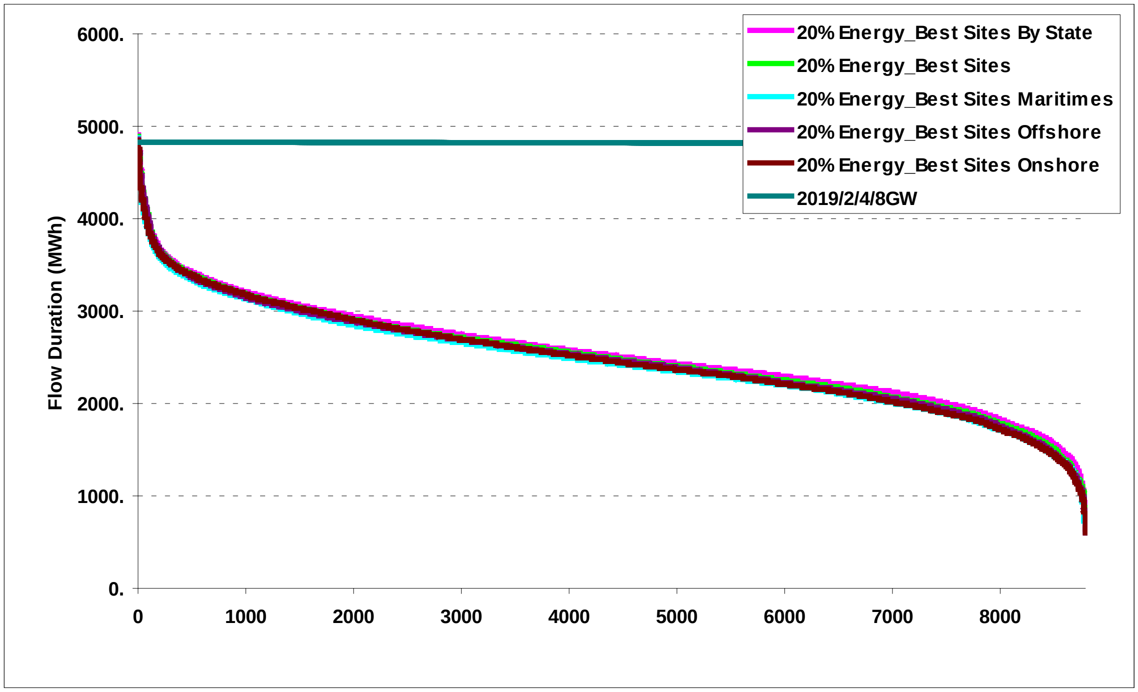


Figure 5–75 Boston Import, S-o-A forecast interface flow, 20% penetration

Figure 5–76 shows the flows across the sum of the ISO-NE to Maritimes interfaces. The blue line represents the total flow in the 20% Energy_Best Sites Maritimes scenario. It shows that the imports into ISO-NE increase substantially with the addition of wind in the Maritimes.

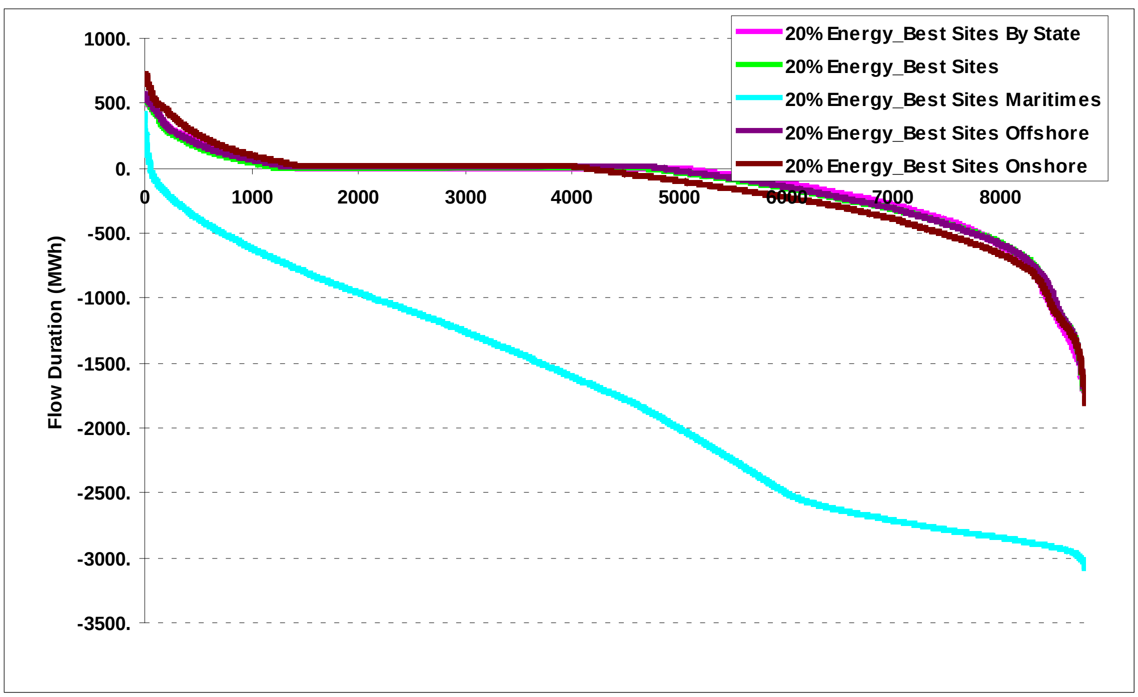


Figure 5–76 ISO-NE to NB (Maritimes case contains HVDC cable from Maritimes to Massachusetts) interface flow, S-o-A forecast, 20% penetration

5.2.2.2 *Ramp and Range Capability*

Figure 5–77 and Figure 5–78 show duration curves of the hourly range up and down capacity available for the various scenarios. The graphs are based on the units that are committed and online. The maximum range up available was roughly 9,900 MW and the minimum was 763 MW. The range down maximum is roughly 14,850 MW and the minimum is 0 MW. This occurs from two to 30 hours for the various scenarios. This is less than 0.3% of the year. In this situation, the wind could potentially be curtailed to free up range down capacity.

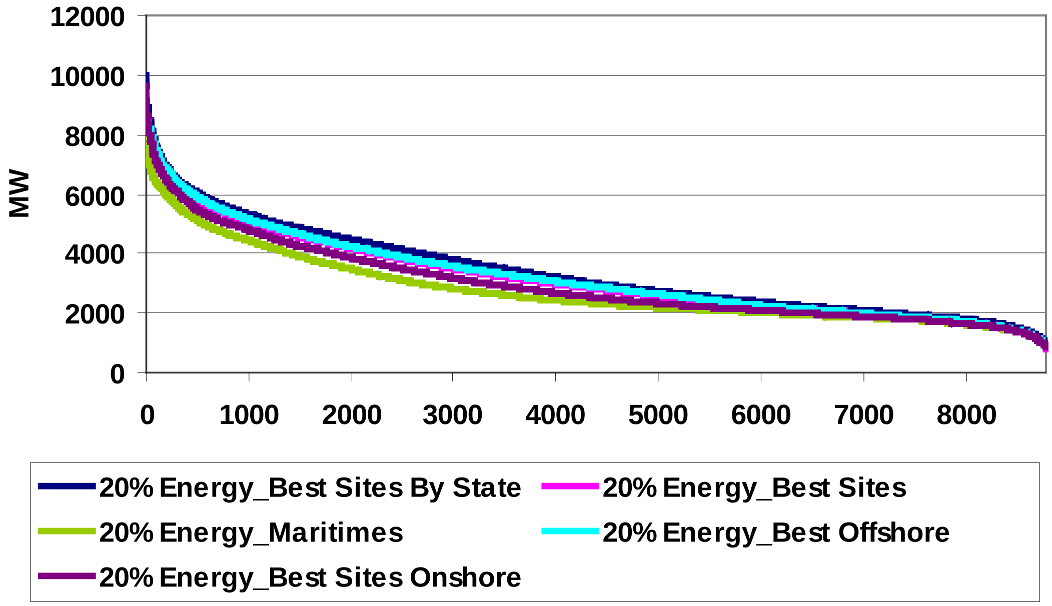


Figure 5–77 Hourly Range Up Capability, S-o-A forecast, 20% penetration

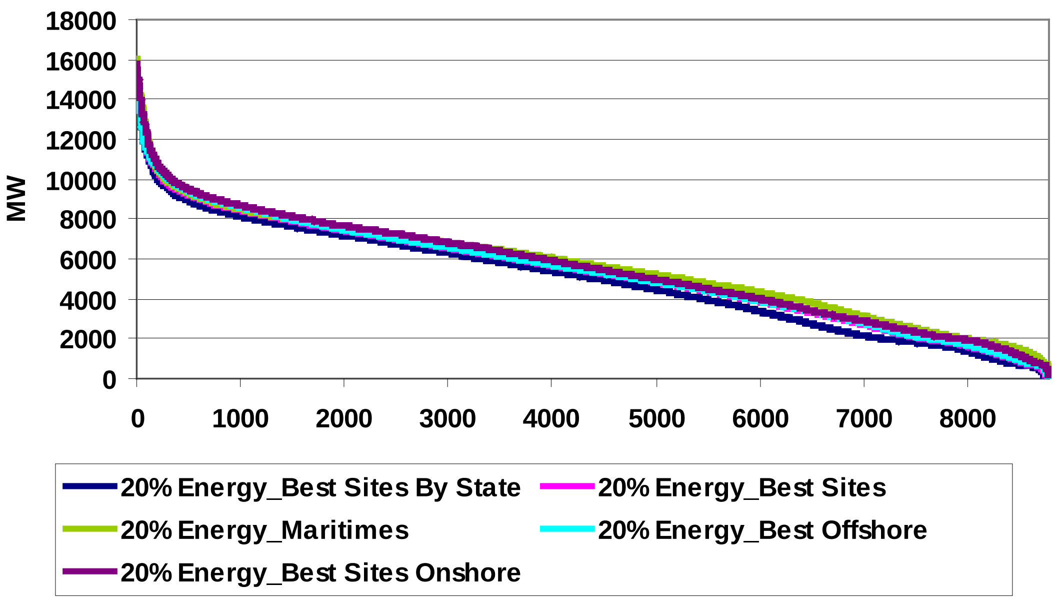


Figure 5–78 Hourly Range Down Capability, S-o-A forecast, 20% penetration

Figure 5–79 and Figure 5–80 compare the range up and down capability for the No Wind and 20% Energy_Best Sites Onshore case. As expected, the range up increases and the range down decreases with wind generation added to the system.

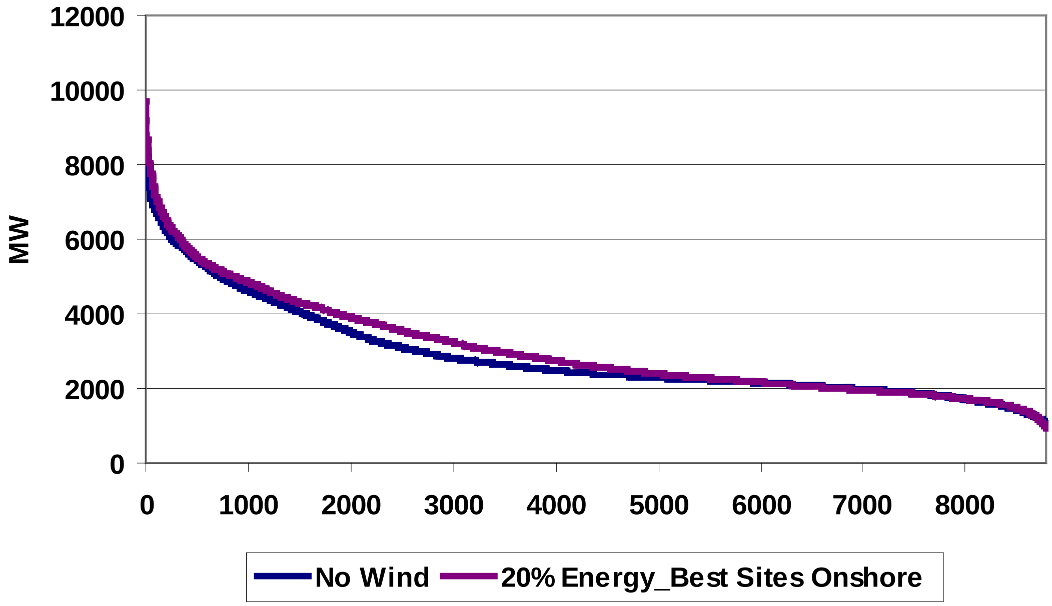


Figure 5–79 Hourly Range Up Capability, S-o-A forecast, No Wind vs. 20% Energy_Best Sites Onshore

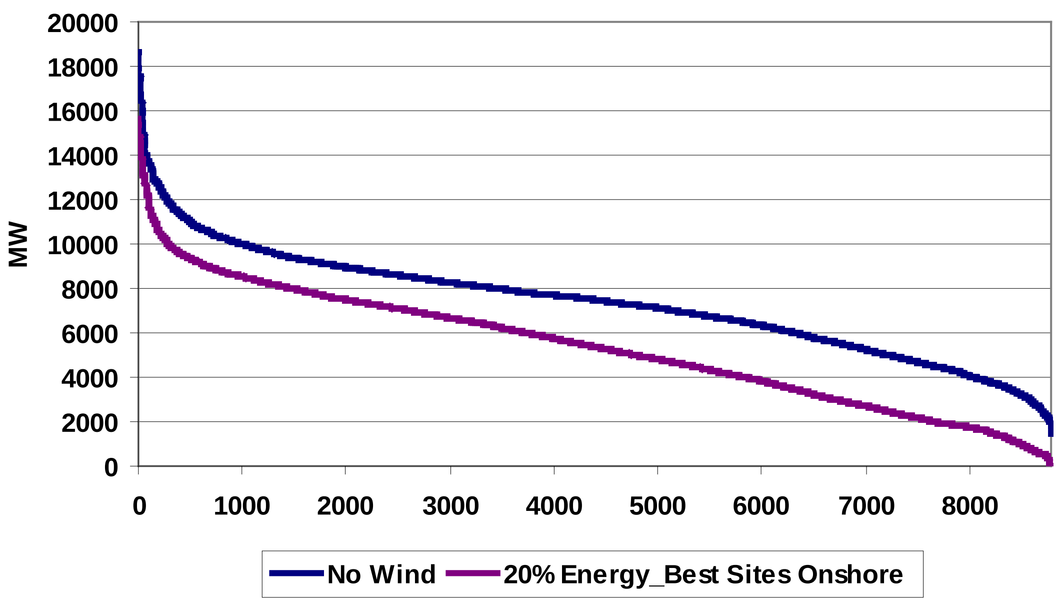


Figure 5–80 Hourly Range Down Capability, S-o-A forecast, No Wind vs. 20% Energy_Best Sites Onshore

Figure 5–81 and Figure 5–82 show duration curves of the hourly ramp up and down capacity available for the various scenarios.

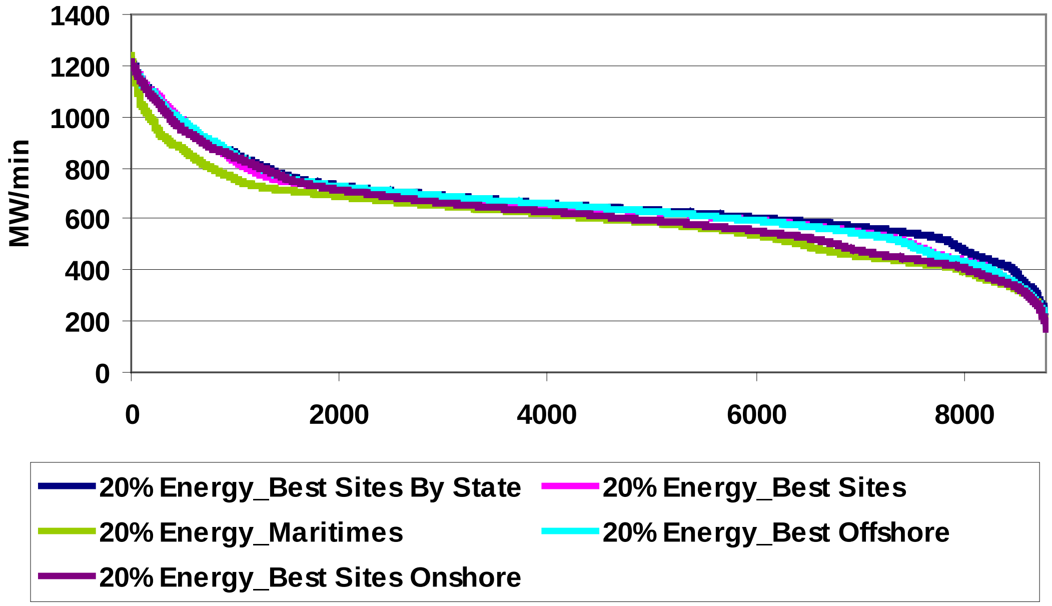


Figure 5–81 Hourly ramp-up capability, S-o-A forecast, 20% penetration

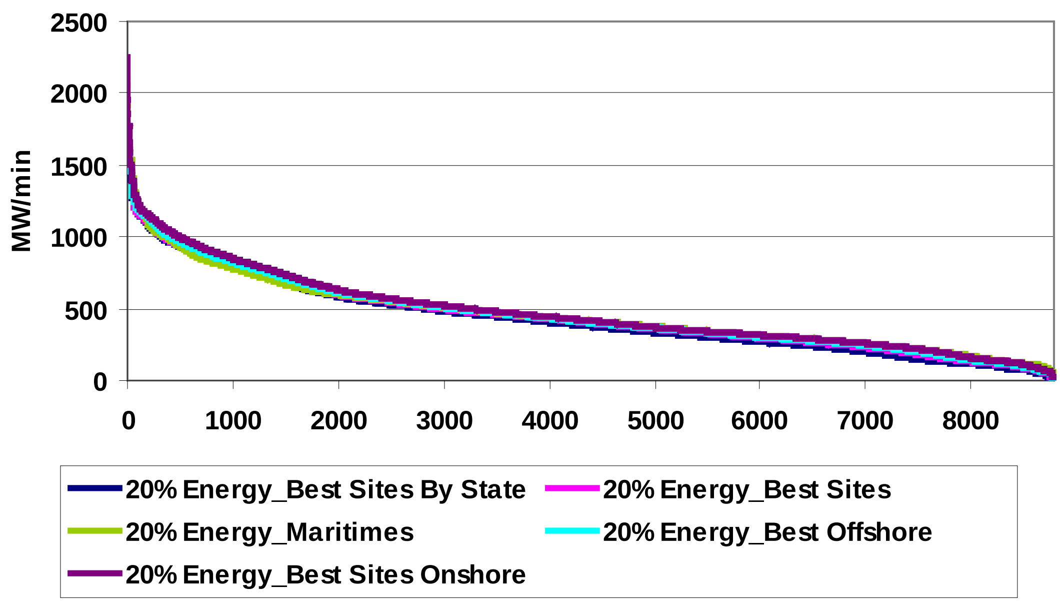
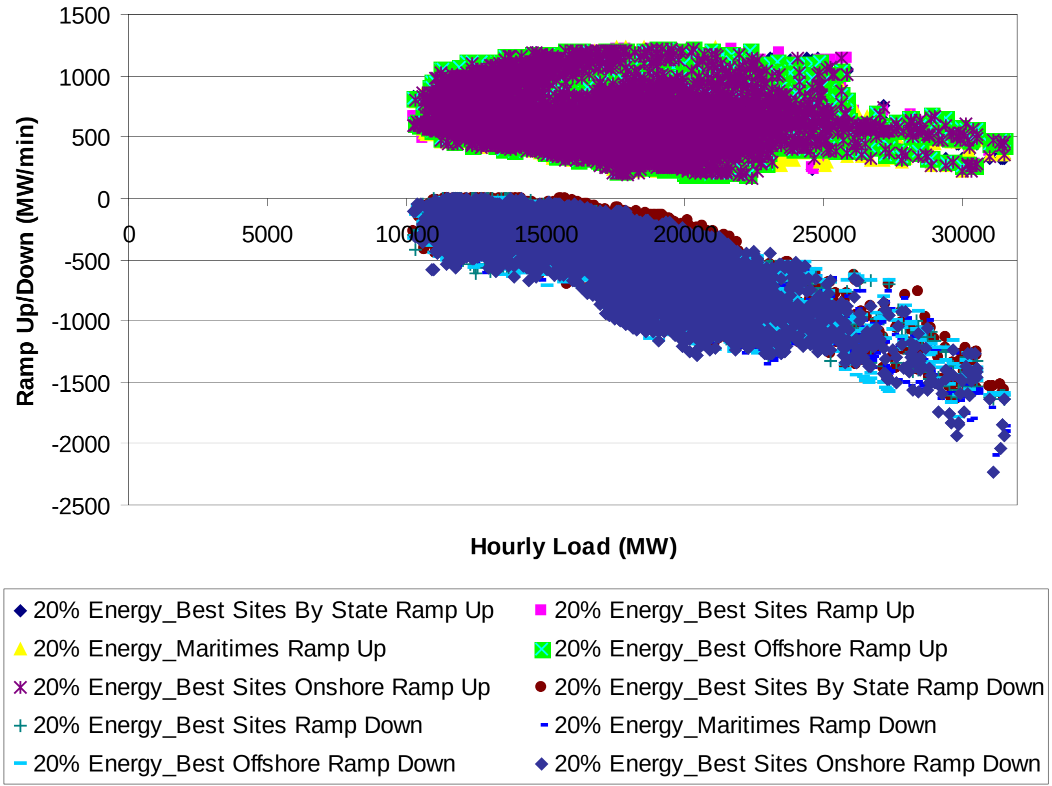


Figure 5–82 Hourly ramp-down MW/min capability, S-o-A forecast, 20% penetration

As can be seen in the figures, the maximum available ramp up is roughly 1,200 MW/min and the minimum is 165 MW/min. This can be compared to the regulation requirements, which increase from roughly 80 MW to 310 MW at 20% penetration, as seen in section 4.6.1. Over a 5-minute period, 310 MW would translate to 62 MW/min, which is less than half of what is available, indicating that the increased regulation requirement could easily be met. The ramp down maximum is roughly 2,200 MW/min and the minimum is 0 MW/min. As expected, the hours at 0 for the ramp down is the same as the range down.

Figure 5–83 compares the hourly ramp up/down capability against the ISO-NE hourly load for all of the 20% scenarios. The upper figure shows the total range and the bottom figure expands the graph to just show the hours with less than +/- 100 MW/min ramping capability. The ten-minute spinning reserve for ISO-NE is 700 MW, which would correspond to a ramp up capability of 70 MW/min. As can be seen from the curve, the ramp up capability never falls below 165 MW/min. Again, from the ramp up side this does not appear to present any difficulty. However, the ramp down capability may be deficient several hundred hours and possibly require either changes to the unit commitment or spilling of some wind energy.



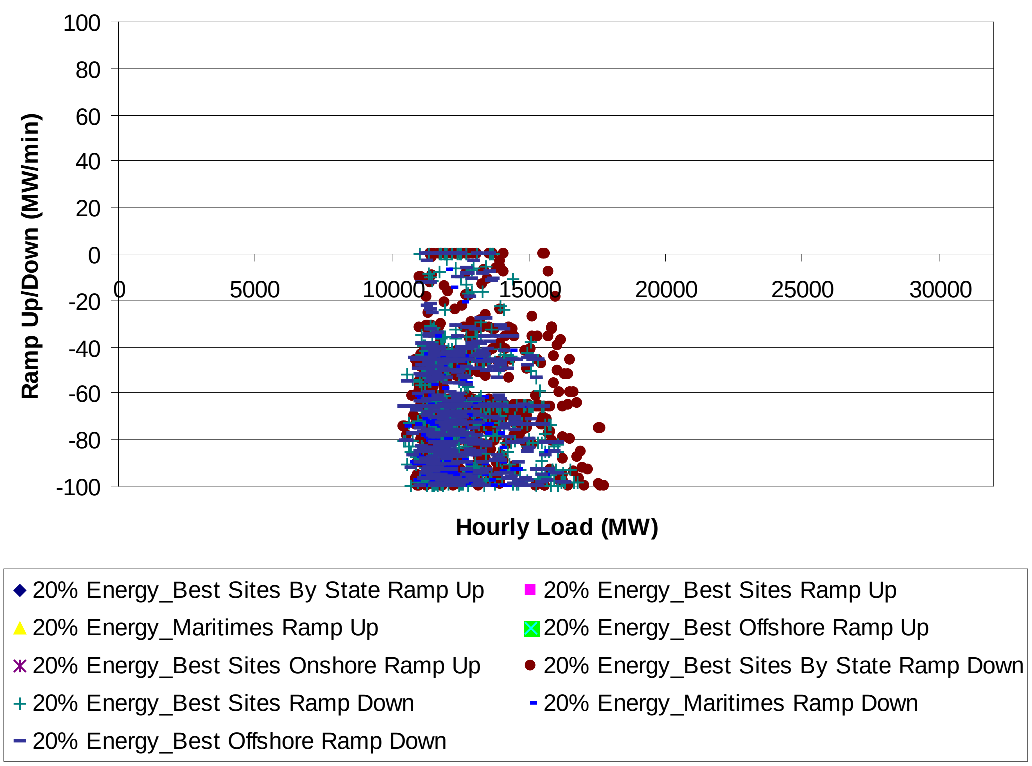


Figure 5–83 Hourly Ramp Up/Down vs. Load, S-o-A forecast, 20% Energy

Table 5–12 shows a summary of the number of hours with less than 100 MW/min of ramp down capability for the various 20% scenarios.

Table 5–12 Number of hours with ramp down capability < 100 MW/minute, 20% scenarios.

Scenario	# Hours
20% Energy_Best Sites By State	612
20% Energy_Best Sites	479
20% Energy_Best Sites Maritimes	225
20% Energy_Best Sites Offshore	451
20% Energy_Best Sites Onshore	374

Figure 5–84 through Figure 5–87 look at the range and ramp for a week in a spring month and summer month for the 20% energy scenarios. The shape is generally the same for the various 20% penetration scenarios. The week of April 13 has some hours where the down range and ramp go to 0 MW. The differences between scenarios are caused by differences in wind generation and a given online resource's dispatch compared to its up or down limits.

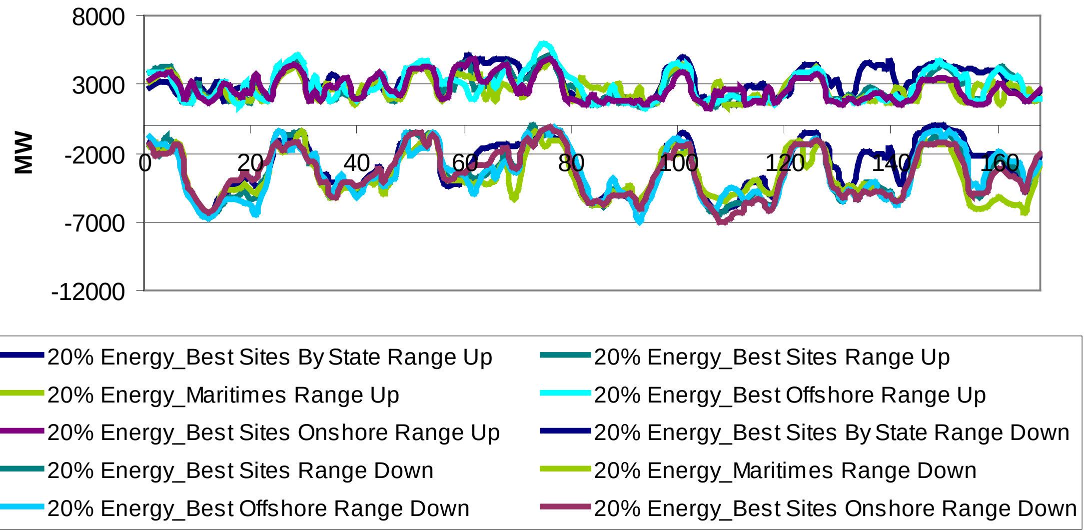


Figure 5–84 Range up/down capability week of April 13, S-o-A forecast, 20% penetration

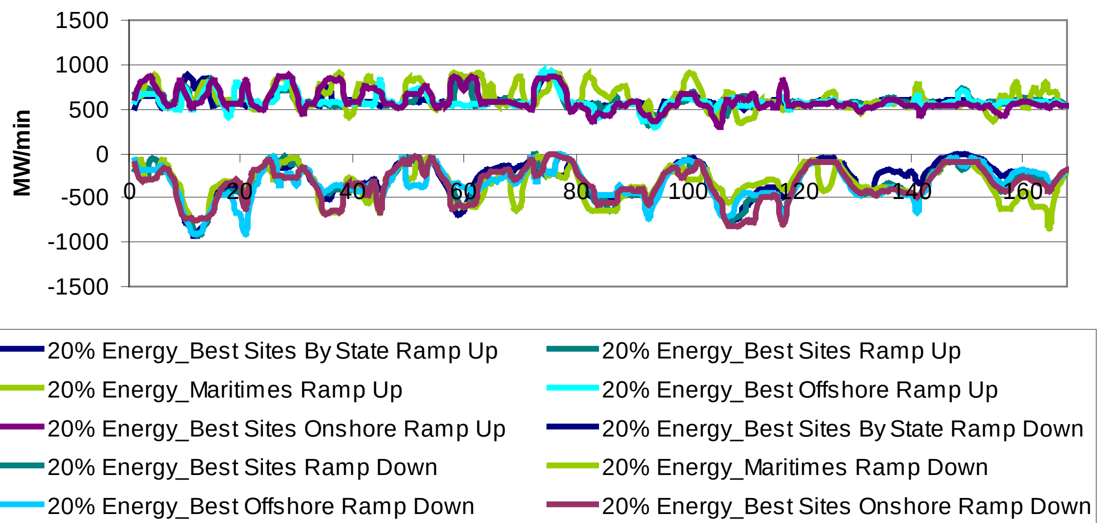


Figure 5–85 Ramp up/down MW/min capability week of April 13, S-o-A forecast, 20% penetration

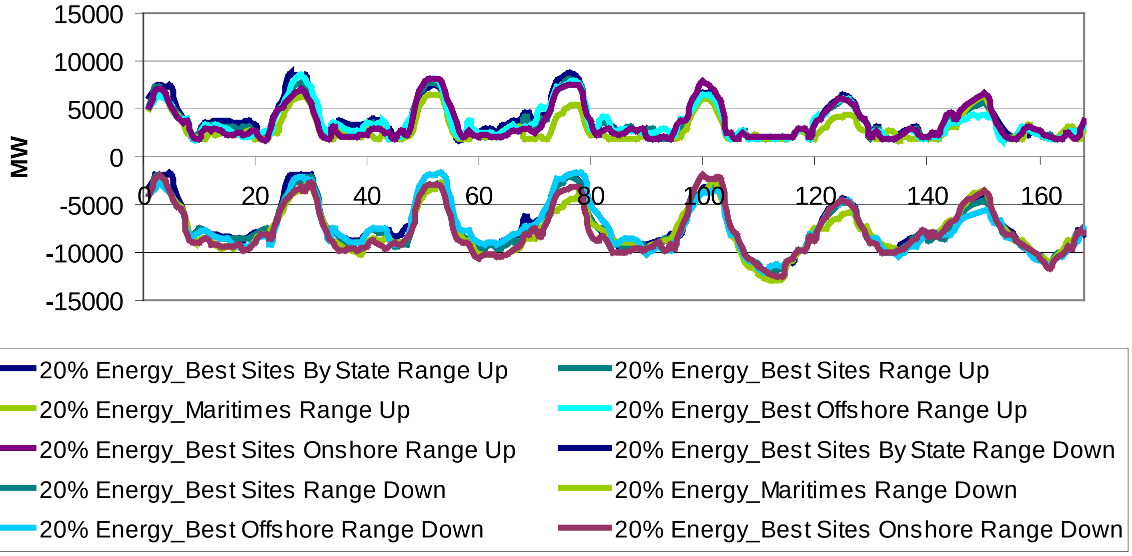


Figure 5–86 Range up/down capability week of July 6, S-o-A forecast, 20% penetration

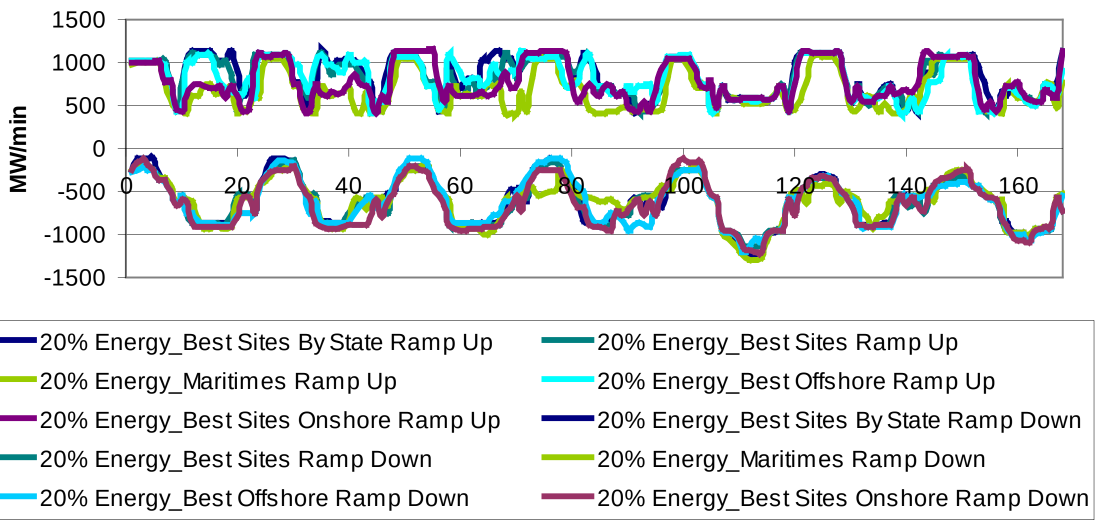


Figure 5–87 Ramp up/down MW/min capability week of July 6, S-o-A forecast, 20% penetration

5.2.3 14% Wind Penetration Key Findings

A similar analysis was performed looking at all of the 14% penetration scenarios. The charts for these, similar to the ones for the additional 20% scenarios, are shown in Appendix C. In general the relative results between the cases were the same as was shown for the 20% cases; however the fuel displacement and emission reductions were smaller due to the reduced wind penetration. The major difference was in the transmission congestion. The 14% penetration cases used the 2 GW overlay while the 20% scenarios used the 4 GW overlay. As was shown, the use of the 4 GW overlay for the 20% penetration cases essentially eliminated the congestion within the system. Although congestion was more of a factor in the 14% it did not seem to significantly affect the operating costs. This is likely due to the fact that gas is on the margin on both sides of the constraints, so that while the constraint is limiting there is not that much of a cost difference behind it. Because the costs were relatively unaffected by the congestion that did occur, the operation of the system was similar to the operation of the system with 20% wind energy.

5.2.4 Value of Forecasts

Figure 5–88 examines the value of the wind forecast as wind penetrations increase. The figure shows the difference in system operating costs between using no forecast and a case with a perfect day-ahead forecast and the corresponding case using a State-of-the-Art forecast.

In the production cost simulation, if no wind forecast is provided, the commitment phase of the model does not include this energy. It shows up in the dispatch phase only. This causes over commitment of thermal units and can lead to excessive spinning reserve and curtailment of the wind. If a perfect forecast is used, the model has perfect knowledge of the wind produced in both phases of the model. When a S-o-A forecast is used, the commitment phase uses an imperfect but relatively accurate day-ahead forecast of the wind. This forecast will be low or high of the actual wind used in the dispatch phase of the program. If the forecast is low compared to the actual wind, over commitment of thermal units will occur and potentially not enough thermal units will be committed. This can lead to increased quick start operation and spinning reserve violations.

Not surprisingly, the importance of the forecast increases at higher penetration levels. But even at the lowest level of penetration using the wind forecast can reduce operating costs by $50 million per year. Another important aspect is that implementation of wind forecasting in the day-ahead commitment and real time dispatch early in the actual wind integration process will allow the system operators to gain experience and comfort levels before it reaches the billion dollar level of impact. The study results show that improving the forecasting can have some benefit, but that the critical aspect is in using the best level of forecasting that is currently available. At higher penetrations the S-o-A forecast appears to provide roughly 94% of the value of using a forecast with perfect knowledge.

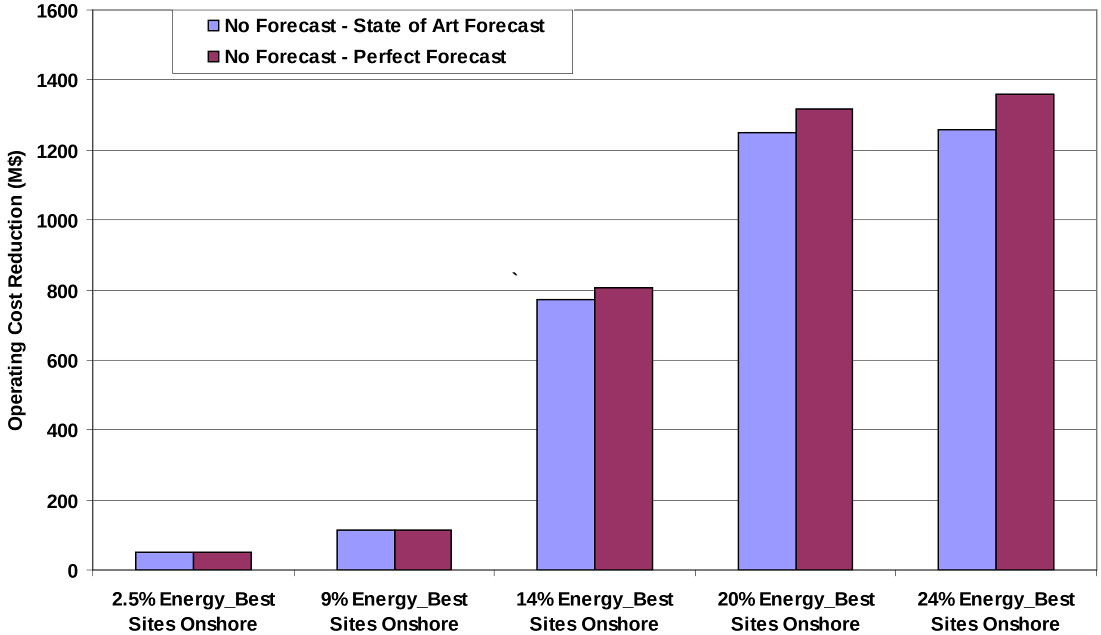


Figure 5–88 System operating cost impacts of forecast (M$), S-o-A forecast, Best Sites Onshore

5.2.5 Annual Profile Sensitivities

Most of the analysis was performed using the load and wind profiles from 2006 to simulate 2020. All of the primary cases were also run using the shapes from 2004 and 2005 using all the same assumptions. As detailed in section 2.1.2, the load extrapolation method used for the study, results in different total load energy for the various shape years. To fully capture the impacts of the different shape years, the loads were ratioed up, so that the annual peak matched the target and the load factor was kept as is.

Table 5–13 summarizes the variations between the different shape years. Although the wind penetration target was 20% energy, the load extrapolation methodology causes lower penetration for each year.

Table 5–13 Annual shape variation summary, 20% Energy_Best Sites Onshore

20% Best Sites Onshore	2004	2005	2006
Peak Load (GW)	31.5	31.5	31.5
Load Energy (GWh)	174,417	160,749	149,241
Load Factor	63%	58%	54%
Wind Capacity (GW)	9.779	9.779	9.779
Wind Energy (GWh)	29,575	28,973	28,832
Wind Capacity Factor	35%	34%	34%
Annual Penetration	17%	18%	19%

Figure 5–89 compares the instantaneous penetrations for each shape year for the 20% Energy_Best sites Onshore. The solid blue line is at the original 20% target mark. The 20% energy was based on the three-year average wind energy (29,060 GWh) and the CELT report forecasted 2020-load energy value (149,241 GWh). As shown, the hourly penetration varies hourly and hit 20% for a very few hours.

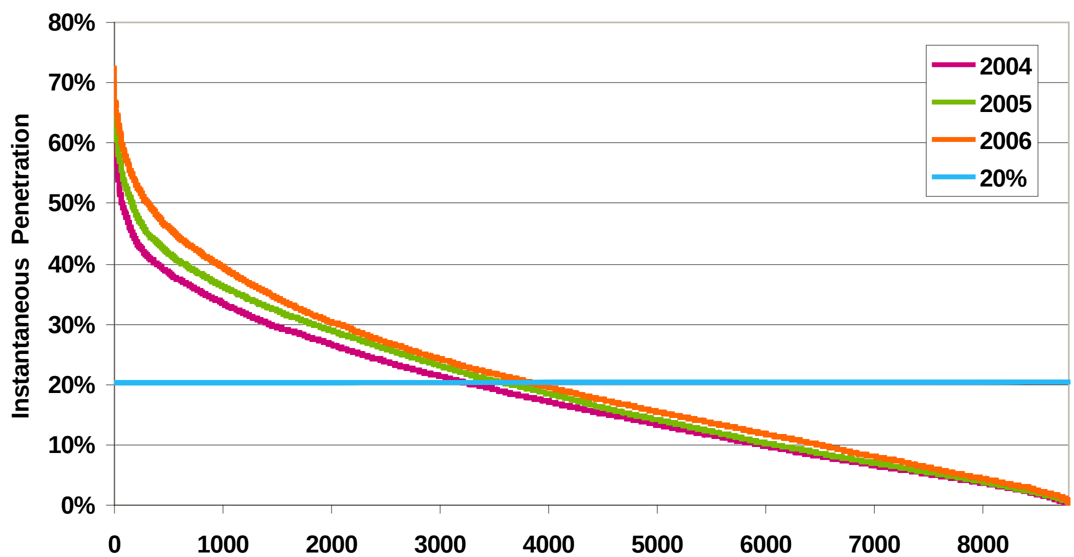


Figure 5–89 Instantaneous wind penetration, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–90 compares the generation by type for the No Wind and 20% Energy_Best Sites Onshore scenario for the three shape years. As expected, the higher load energy in 2004 and 2005 causes the need for more overall generation as compared to 2006. This results in more CC operation. As we saw in previous results, the wind displaces mostly CC generation.

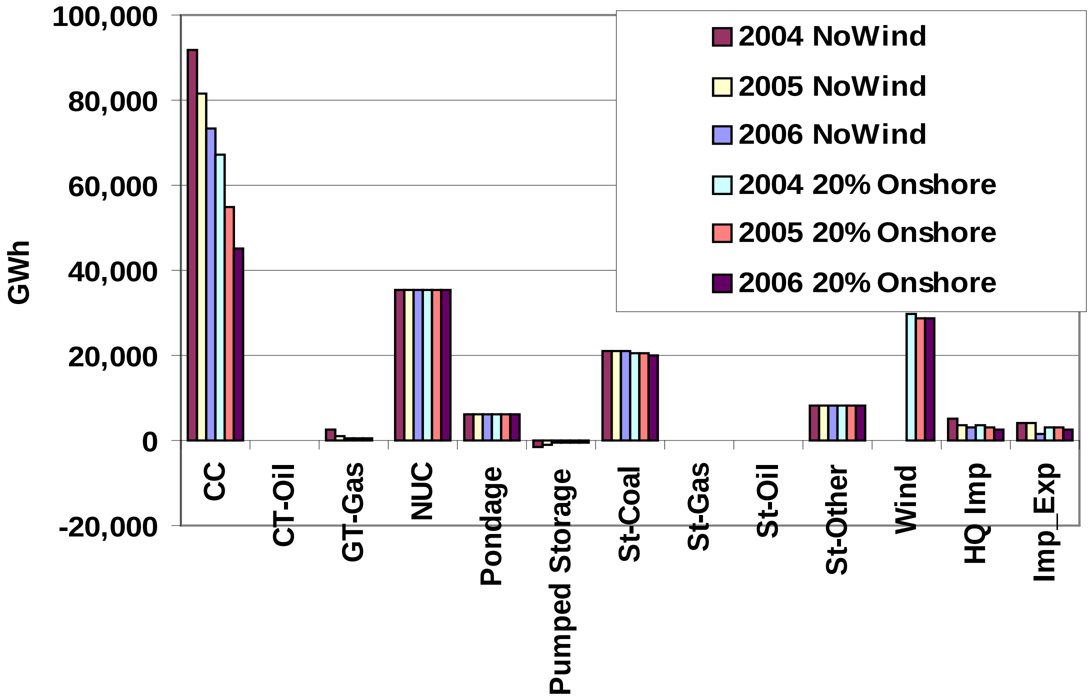


Figure 5–90 ISO-NE generation by type, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–91 zooms in on the peaking operation for the 3 shape year cases. The wind penetration drops the operation for the 3 shape years to similar levels. The 2004 extrapolated load has a higher load factor than the other two years. This results in higher peaking operation. With the addition of wind, the wind shifts the dispatch stack up and CC operation replaces the most of the peaking operation.

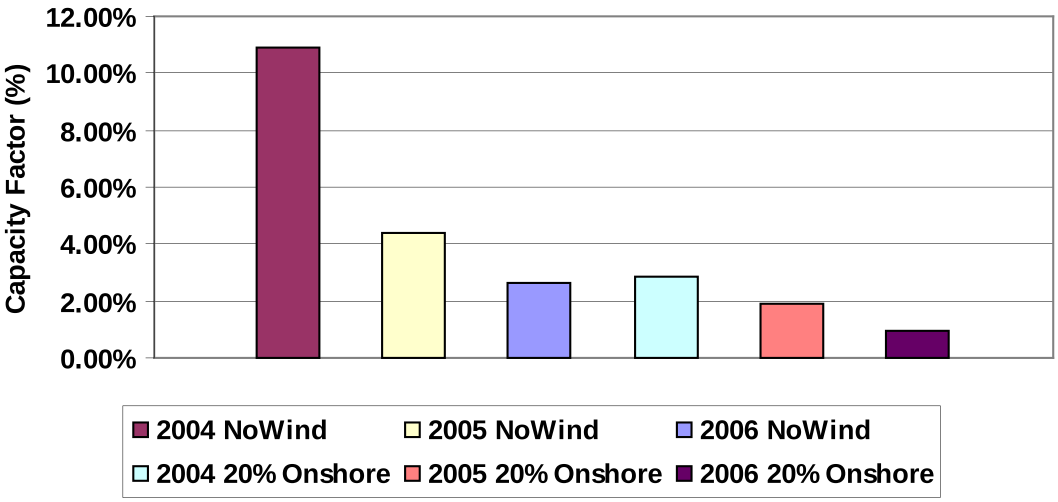


Figure 5–91 ISO-NE peaking plant operation, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–92 shows the ISO-NE load weighted annual average LMP. As expected, the 2004 No Wind case has the highest LMP value while the 2006 20% Energy_Best Sites Onshore has the lowest. The wind penetration has the greatest impact on LMP for the 2004 shape year case as it displaces the largest amount of peaking operation in this year. The addition of wind also reduces the LMP in the 2005 and 2006 shape year cases.

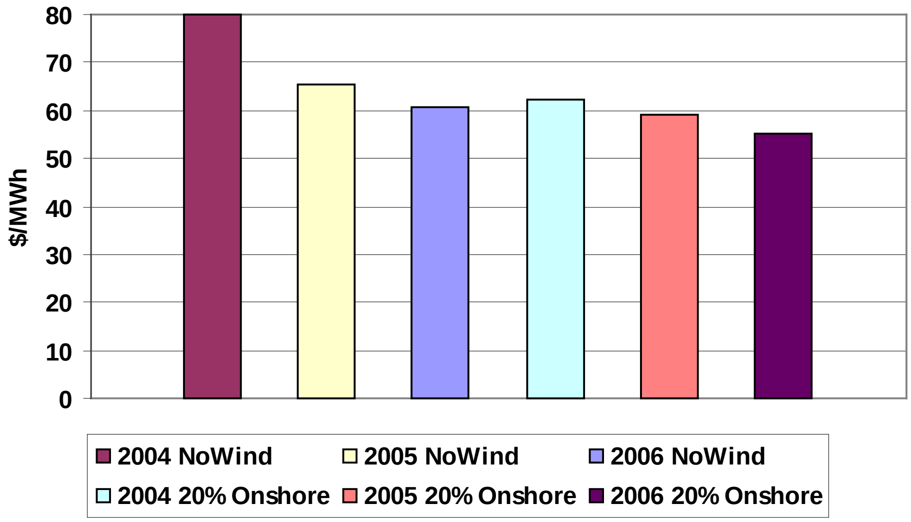


Figure 5–92 Average load weighted ISO-NE LMP, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–93 compares the LMP duration curves for the three annual shapes. With no renewable generation on the system, the LMP ranges from a high of approximately $400/MWh to a low of about $38/MWh. All of the 20% penetration scenarios have similar impacts on the spot price for the three shape years. Introducing 20% penetration of wind to the system, reduces highest cost for all three-shape years by roughly $40/MWh and the lowest hours by roughly $30/MWh.

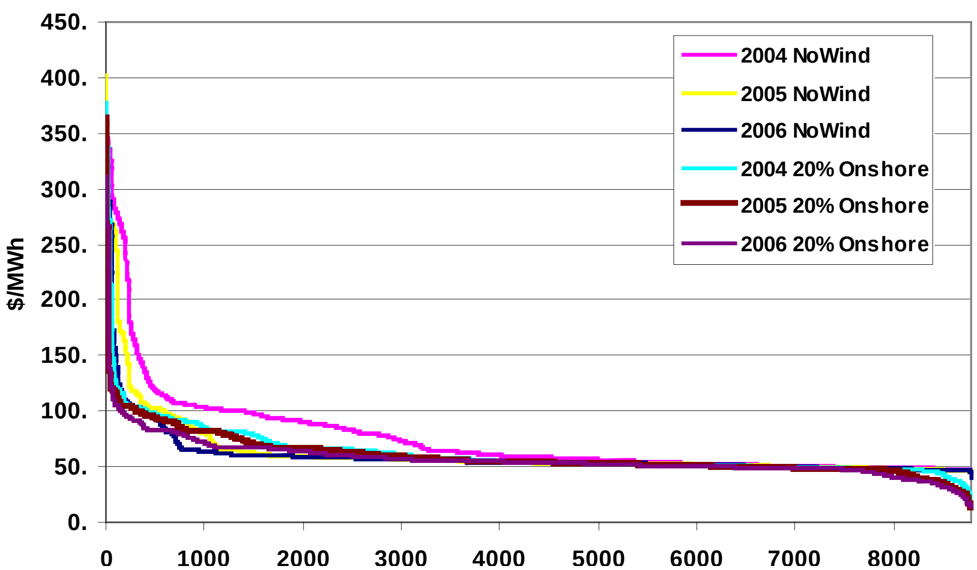


Figure 5–93 Annual LMP duration curve, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–94 compares the PSH operation for the three different shape years with and without wind. With the addition of 20% wind penetration, the PSH operation decreases. This may be counterintuitive.

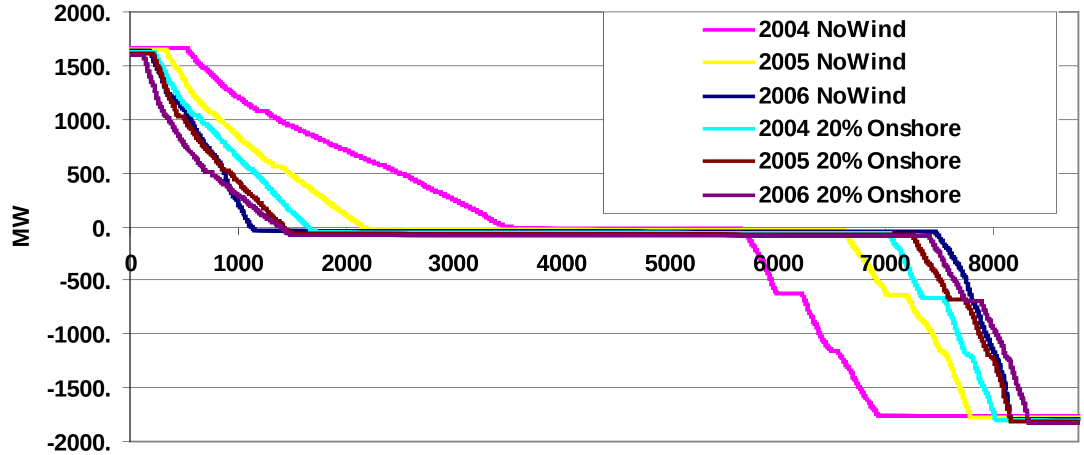


Figure 5–94 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, 20% penetration, by shape year

Figure 5–95 shows the annual price duration comparing the 2004 shape No Wind vs. 20%_Energy Best Sites Onshore S-O-A and Perfect forecast. As can be seen in the figure, the price is typically lower for the 20% cases. The perfect forecast result is a proxy for what the PSH would be dispatched against. PSH is scheduled a week ahead and it would be based on the forecast, so when it is being scheduled it has perfect knowledge of the wind and would not change based on forecast error

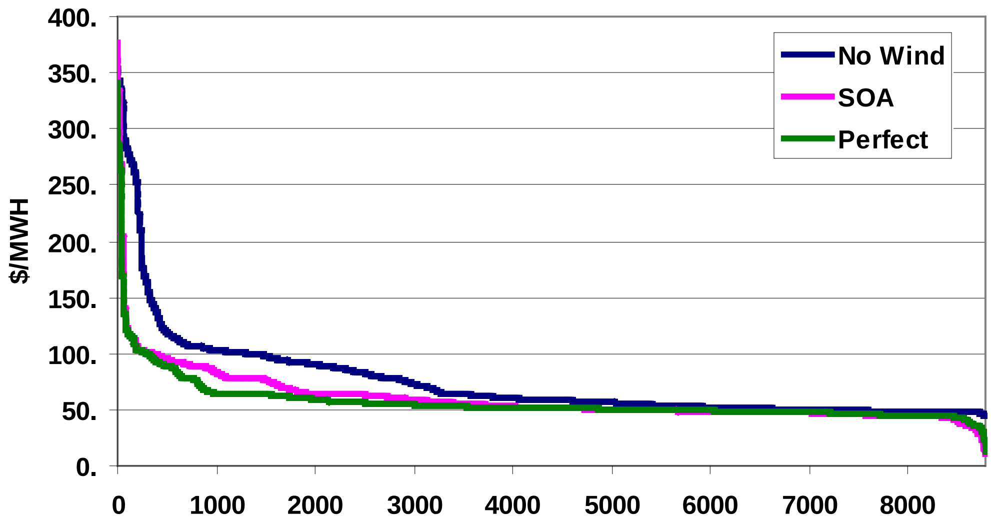


Figure 5–95 2004 shape year annual LMP duration curve comparison

Figure 5–96 shows the LMP for the three cases discussed above for the week of April 1, 2020. It also includes the wind energy for the week. As can be seen in the figure, for this week, even during the periods of lowest wind generation there is still about 1000 MW wind generation being produced. Note that the "Perfect" spot price no longer has much range for economic storage operation

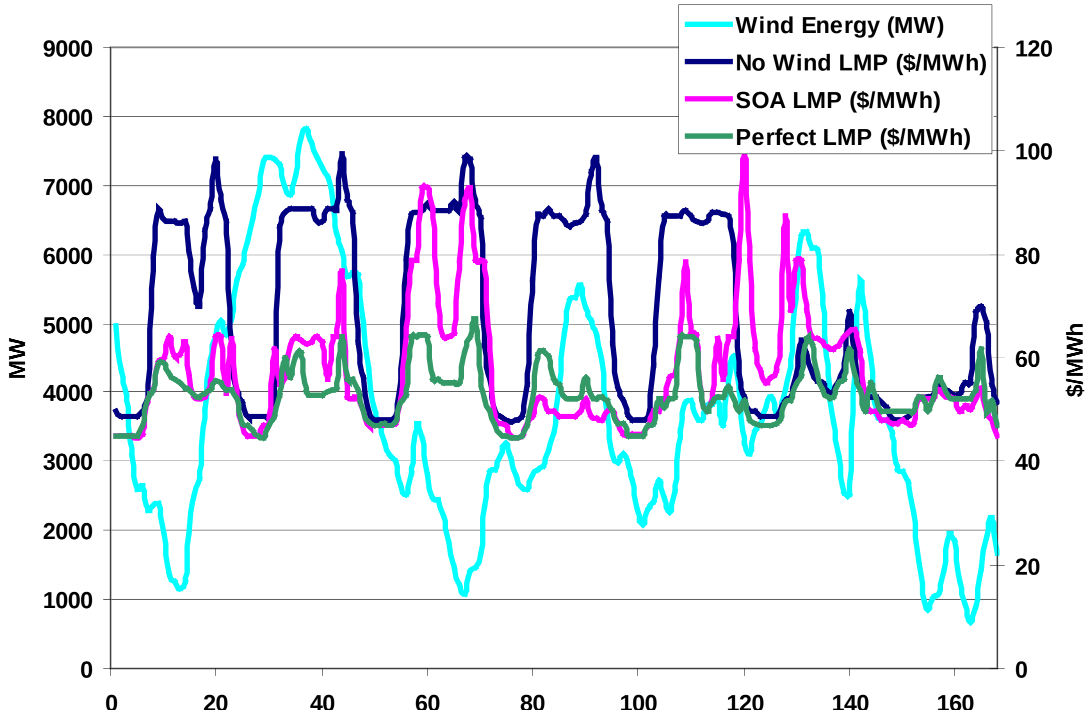


Figure 5–96 2004 shape year LMP comparison, wind energy, Week of April 1

Figure 5–97 shows the variation in the value of the wind generation as a function of shape year. Although the load energy varies, the annual variations are within a few $ MWh.

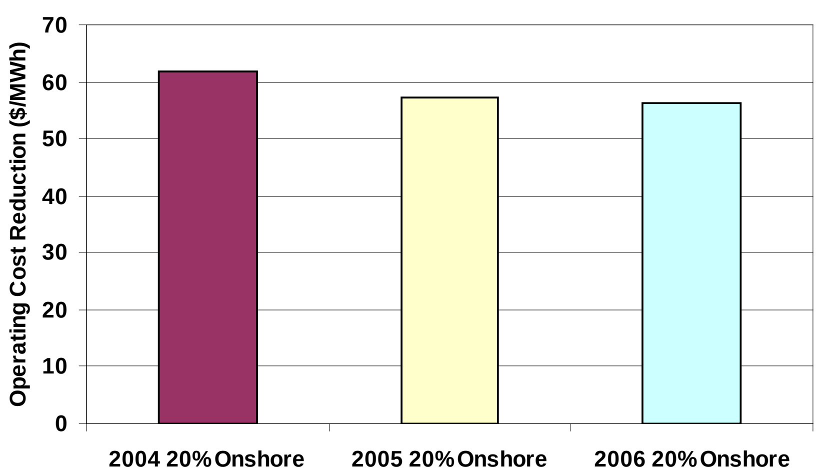


Figure 5–97 ISO-NE operating cost reduction per MWh of wind generation, S-o-A forecast, 20% Energy_ Best Sites Onshore, by shape year

Table 5–14 summarizes the number of hours that the ISO-NE interfaces were limiting or at their maximum value. The table shows the number of hours each interface was limiting, in the No Wind scenario and the 20% Energy_Best Sites Onshore scenario, for the 2020 simulation when the 2004, 2005, and 2006 load and wind shapes were used. As shown in Table 5–13, using the 2004 load shape has the highest load factor of the three years. Not surprisingly, the No Wind scenario using this shape has the highest amount of hours with the interfaces limiting. The No wind scenario using the 2005 and 2006 shapes has considerably less limiting hours. The 20% Energy_Best Sites Onshore scenarios with the different shapes have similar much lower hours limiting than the no wind. Although some hours still exist with the interfaces limiting, the Governors' 4 GW overlay was built adequately to handle the varying load amounts when using the different shape years.

Table 5–14 ISO-NE Interface Hours Limiting

Interface	2004 No wind	2005 No wind	2006 No wind	2004 20% Energy_Best Sites Onshore	2005 20% Energy_Best Sites Onshore	2006 20% Energy_Best Sites Onshore
North-South	3653	1784	1795	542	460	326
Boston Import	0	0	0	3	2	4
New England East-West	0	0	0	0	0	0
Connecticut Export	0	0	0	0	0	0
Connecticut Import	0	0	0	0	0	0
Southwestern Connecticut Import	0	0	0	0	0	0
Norwalk-Stamford Import	0	0	0	0	0	0
New York-New England	455	731	119	357	910	412
Orrington South	3026	1293	656	0	0	0
Surowiec South	81	55	37	575	410	311
Maine-New Hampshire	27	0	2	0	0	0
SEMA Export	0	0	0	0	0	0
West - East	0	0	0	0	0	0
NB - NE	631	518	283	683	523	559
SEMA/RI Export	63	0	6	0	0	0

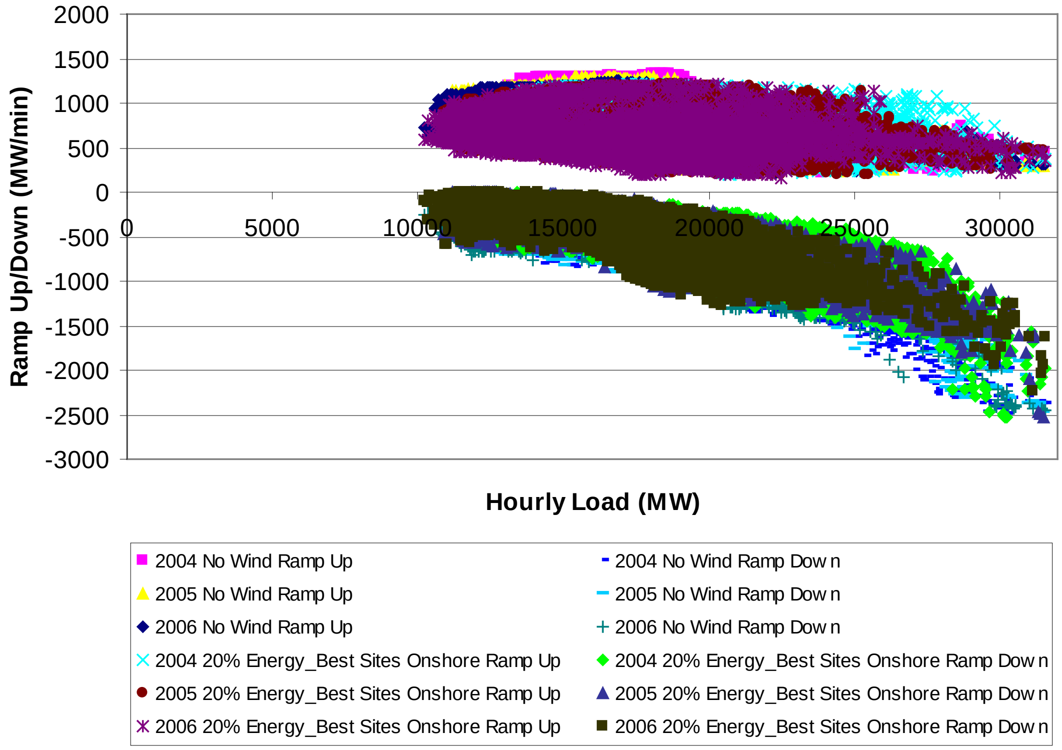
5.2.5.1 Ramp and Range Capability

Figure 5–98 compares the hourly ramp up/down capability against the hourly load for the No Wind and 20% Energy_Best Sites Onshore scenarios for the three years of shapes. The upper figure shows the total range and the bottom figure expands the graph to just show the hours with less than +/- 100 MW/min ramping capability. The ten-minute spinning reserve for ISO-NE is 700 MW, which would correspond to a ramp up capability of 70 MW/min. As can be seen from the curve, the ramp up capability never seems to be a problem. The regulation requirement at the 20% wind penetration level is roughly 400 MW (see section 4.4.1). Again, from the ramp up side this doesn't appear to present any difficulty. However, the ramp down capability is deficient several hundred hours and may possibly require either changes to the unit commitment or spilling of some wind energy.

Table 5–15 shows a summary of the number of hours with less than 100 MW/min of ramp down capability for the six cases shown. While none of the No Wind cases showed any hours with the ramp down capability less than 100 MW/minute there was considerable differences between the three years for the 20% cases.

Table 5–15 Number of hours with ramp down capability < 100 MW/minute, various study years.

Scenario	# Hours
2004 No Wind	0
2005 No Wind	0
2006 No Wind	0
2004 20% Energy_Best Sites Onshore	103
2005 20% Energy_Best Sites Onshore	208
2006 20% Energy_Best Sites Onshore	374



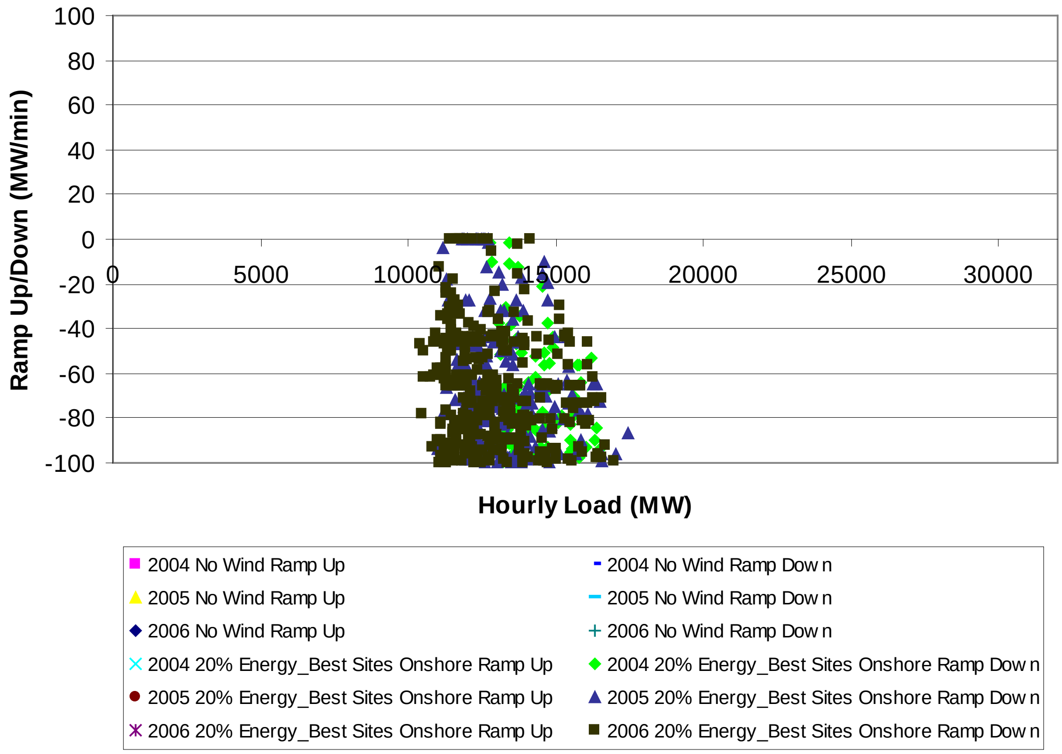


Figure 5–98 Hourly Ramp Up/Down vs. Load, Shape Year Comparison

5.3 Additional Operational Sensitivities

The following section looks at various sensitivities. All sensitivities were done using the No Wind and 20% Energy_Best Sites Onshore scenario or 20% Energy_Best Sites Maritimes scenarios. All were paired with their corresponding constrained transmission configuration (i.e. 2019 ISO-NE and 4 GW Governors overlay) full transmission and the 20% Energy_Best Sites Onshore and 20% Energy_Best Sites Maritimes scenario used a S-o-A wind forecast.

5.3.1 Carbon Price Sensitivity

The following section analyzes the impacts of adding a carbon cost to the entire system studied. The 20% Energy_Best Sites Onshore case, which contains no carbon cost, was compared to the identical case with a \$40/ton of CO2 and \$65/ton of CO2 cost adder to observe the impacts of carbon prices on the New England bulk power system. In addition, the same analysis was performed on the No Wind case.

Figure 5–99 shows the generation by type for the 20% Energy_Best Sites Onshore case, the No Wind case, and these cases with both a \$40/ton and \$65/ton carbon cost added.

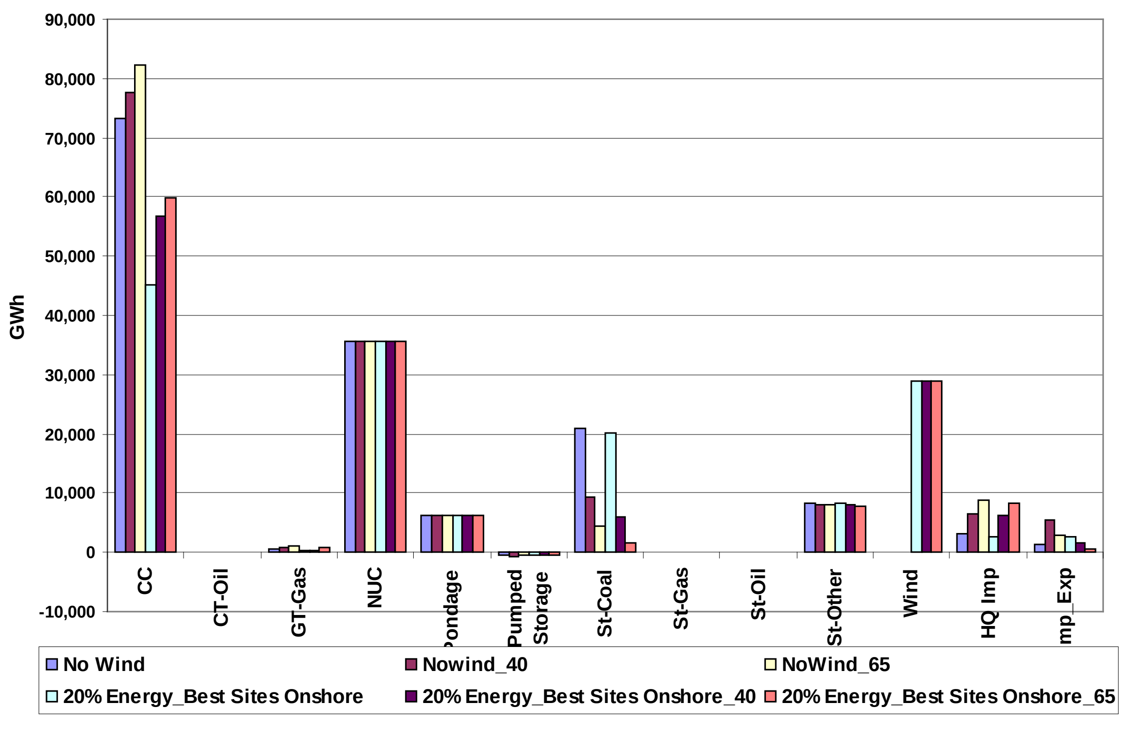


Figure 5–99 Carbon cost impact on ISO-NE generation by type

In both scenarios, it can be seen in the figure that St-Coal generation is largely displaced by combined cycles as the carbon cost increases. Steam-coal units produce approximately 1 ton of

CO2 per MWh of energy vs. approximately 0.6ton tons of CO2 per MWh of energy for gas fired units. Because of the much higher efficiencies possible with combined cycle generation these resources may emit 0.4 tons/MWh of CO2. The additional costs due to carbon prices on coal-fired units vs. gas-fired units will force coal to be above the margin on a more regular basis, and operate less frequently. It can also be seen that imports, particularly those from HQ where no carbon cost was added, increase along with the carbon cost due to the higher prices in ISO-NE. In the scope of this study, it was not possible to analyze the dynamics of a carbon cost on the price of fuels that may increase the cost of gas and decrease the delivered price of coal.

Figure 5–100 compares the full load costs for cc's and St-Coal units given no carbon cost and a $40/ton carbon cost, with respect to gas price. Given an average Full Load Heat Rate (FLHR) or average heat rate at the unit's maximum operating point by type of unit and a $2.86/ton coal price, it can be seen that the full load cost for a CC unit will be lower than that of St-Coal unit when gas prices drop to approximately $4/MMBTU. Under a $40/ton CO2 policy and the same delivered coal price assumption, the effective coal dispatch price would increase from $30/MWh to $70/MWh. The gas price would only need to drop to approximately $6.25/MMBTU for a CC to have a lower full load cost than a St-Coal unit. Some displacement occurs at higher gas prices because the incremental heat rates of a CC and St-Coal units have a great deal of variation displacement of St-Coal can be seen with the increase in Carbon price in Figure 5–99.

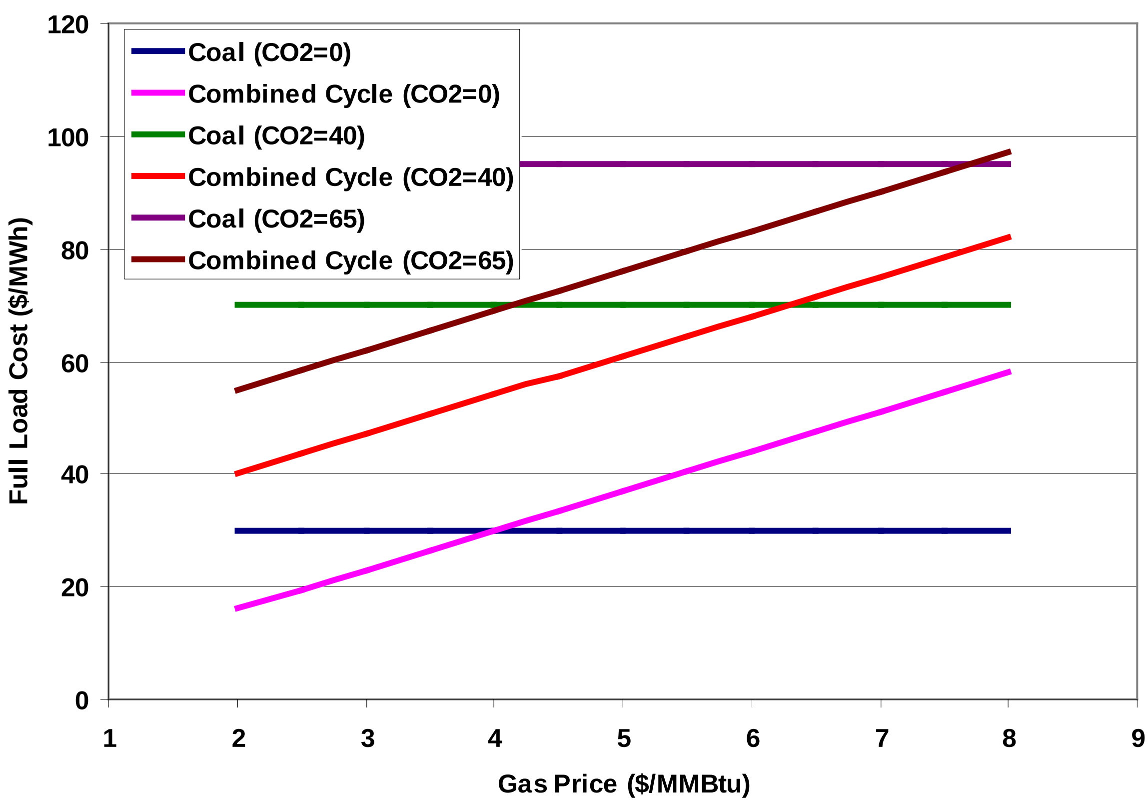


Figure 5–100 Steam Coal vs. Combined cycle full load variable cost

The revenue by type comparison is shown in Figure 5–101. As expected, the largest increase in revenue occurs for the CC generation. This is mainly due to the additional generation shown in Figure 5–99 and the higher prices in ISO-NE due to the carbon cost. Other types of generation unaffected by the carbon cost, such as wind and nuclear also have revenue gains due to higher ISO-NE prices.

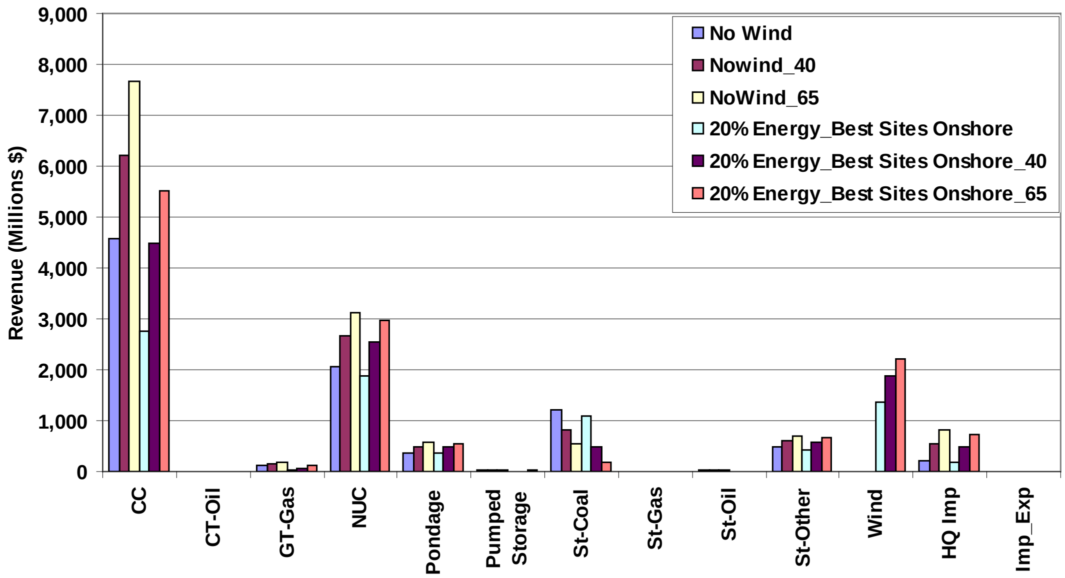


Figure 5–101 Carbon cost impact on ISO-NE revenue by type

Figure 5–102 compares the value of the wind generation between the original and carbon cost scenarios. Wind energy becomes more valuable as the price of carbon increases due to the increased costs for CO2 emitting generation, while wind costs remain unchanged. A $65/ton carbon cost increases the value of the wind by over $30/MWh.

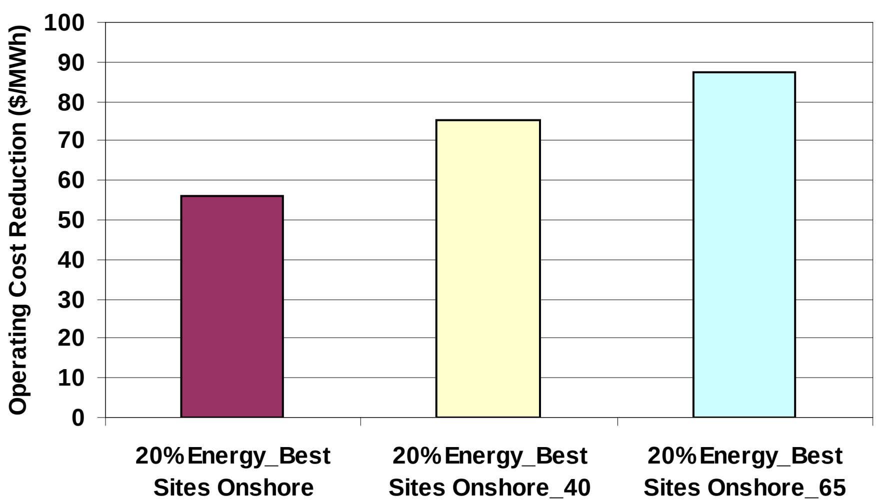


Figure 5–102 Carbon cost impact on ISO-NE operating cost reduction per MWh of wind generation

Figure 5–103 compares the LMP duration for the six scenarios. The No Wind cases increase in price with the addition of a carbon cost. The 20% Energy_Best Sites Onshore results are similar.

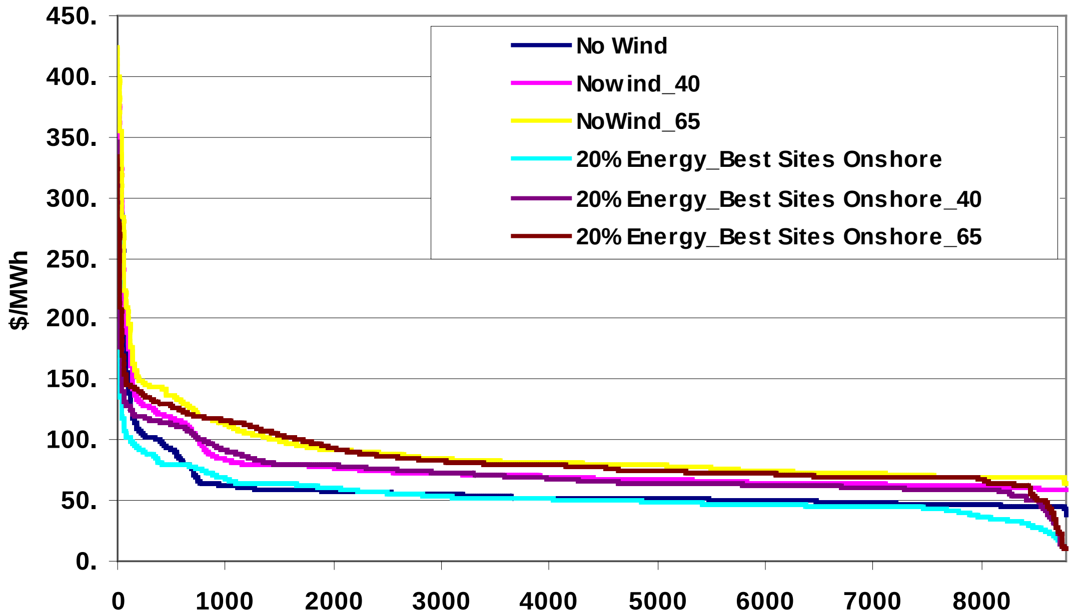


Figure 5–103 Carbon cost impact on ISO-NE annual LMP duration curve

Figure 5–104 compares the weighted average annual LMP for ISO-NE. As implied in Figure 5–102, as the carbon cost increases, LMPs increase substantially.

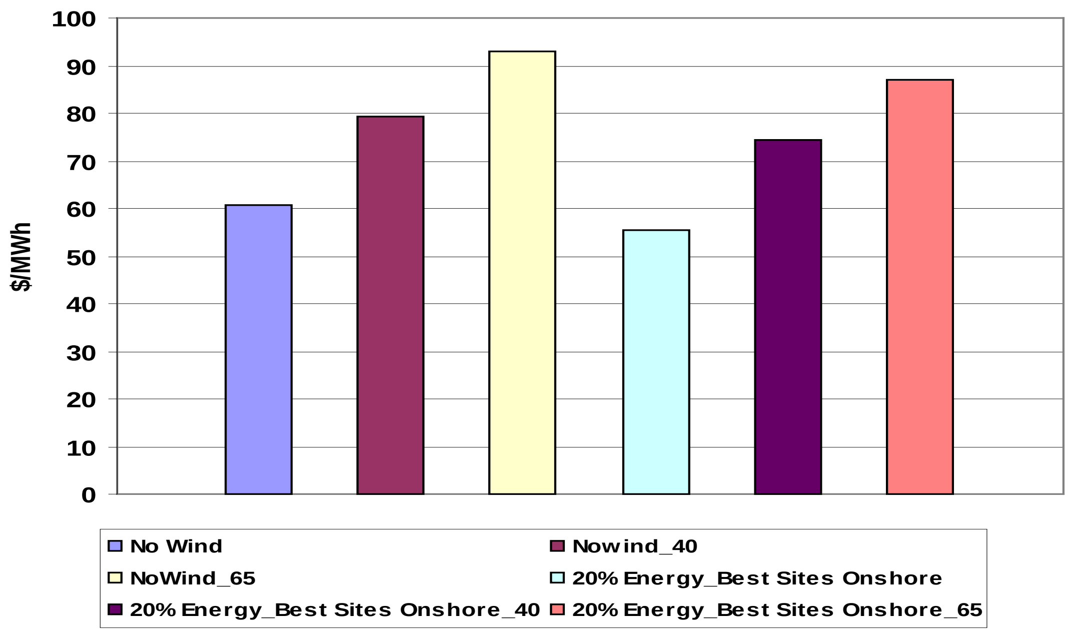


Figure 5–104 Carbon cost impacts on annual load weighted average ISO-NE LMP

Figure 5–105 below shows the ISO-NE emissions for each scenario. Due to the large decreases in coal plant production, SOx output drops off significantly. As expected, CO2 output also drops as the carbon cost increases.

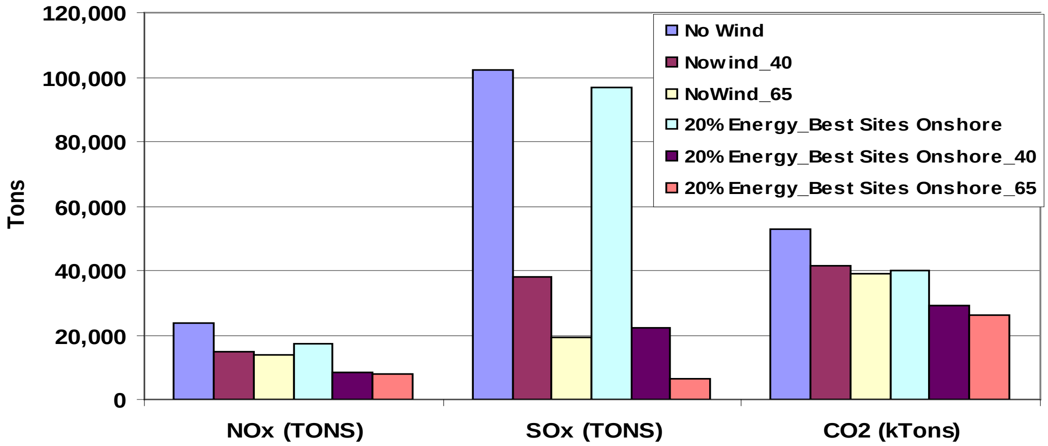


Figure 5–105 Carbon cost impact on ISO-NE emissions

5.3.2 Fuel Price Sensitivity

In addition to the CO2 sensitivities, a fuel price sensitivity taking into account carbon cost was also analyzed. The No Wind and 20% Energy_Best Sites Onshore with $65/ton carbon cost were modeled with a higher and lower fuel price for all types of fuel. In the high fuel price scenario, gas, oil, and coal were each doubled. In the low fuel price scenario, the price of each fuel was reduced by 25%.

Figure 5–106 shows the ISO-NE generation by type for each of the six scenarios. In the low fuel case, gas prices are reduced by $2/MMBTU in ISO-NE while coal is reduced by approximately $.70/ton in the same area. It can be seen that CC units increase their output and displace nearly all St-Coal units due to the combination of impacts from the $65/ton carbon policy and the reduced fuel prices. The high fuel case results in a gas price increase of $8/MMBTU and a coal price increase of approximately 3$/ton. The large increase in costs for gas-fired units allows St-Coal to partially displace CC generation.

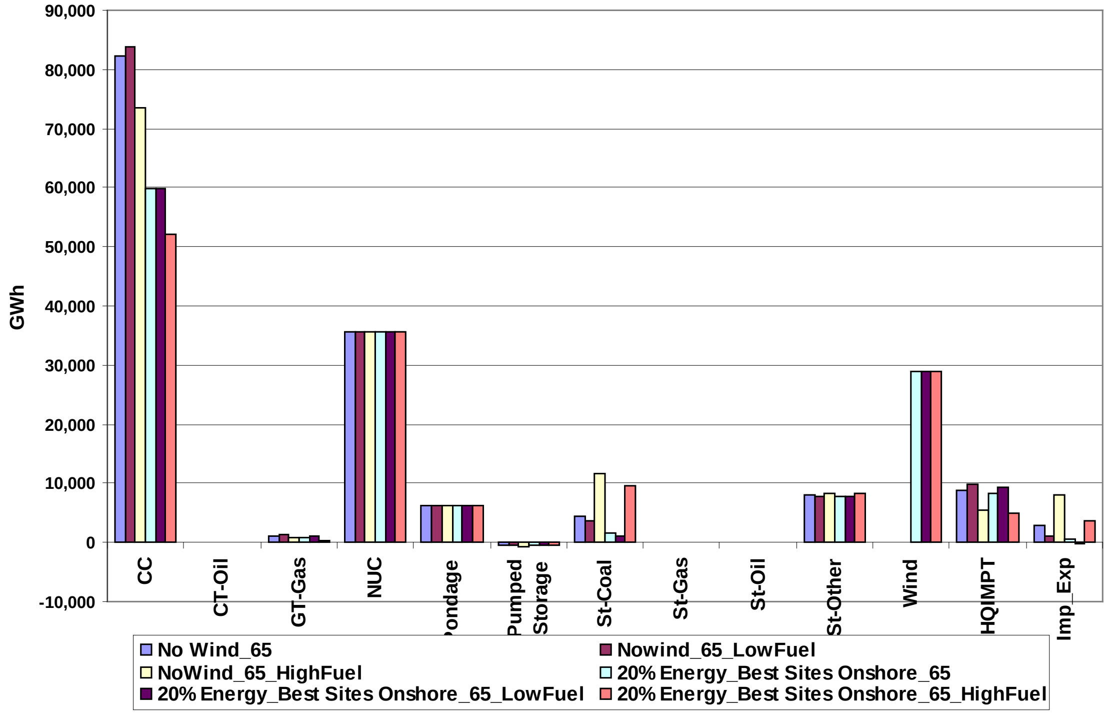


Figure 5–106 Fuel price impact on ISO-NE generation by type

Figure 5–107 shows the ISO-NE revenue by type of unit, while Figure 5–108 shows the ISO-NE total variable cost by type. As the fuel price increases, revenue increases due to higher spot prices; however, total variable cost for non-nuclear thermal generation is also driven up by the increase in fuel price.

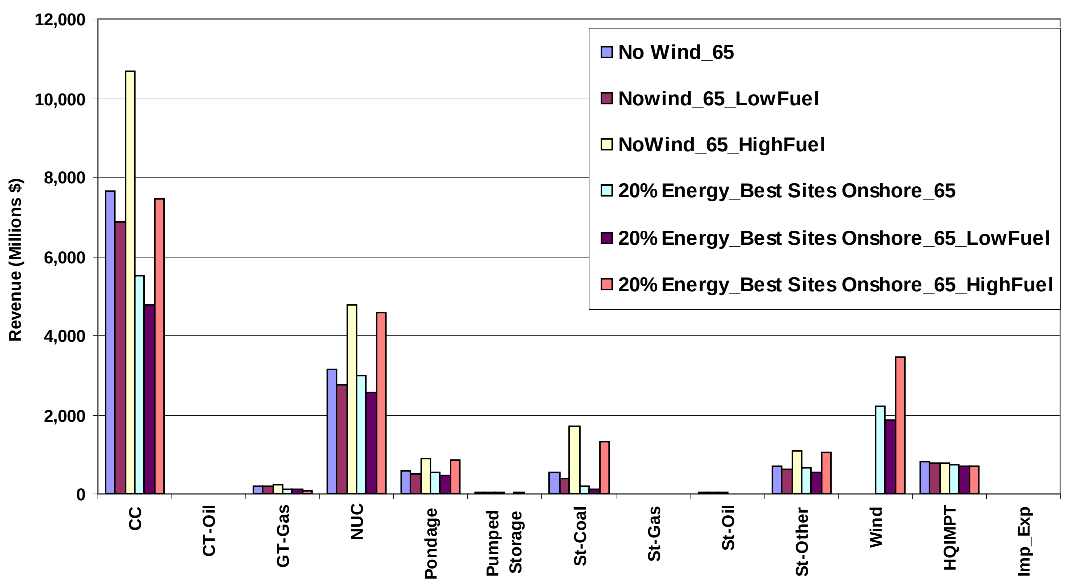


Figure 5–107 Fuel price impact on ISO-NE revenue by type

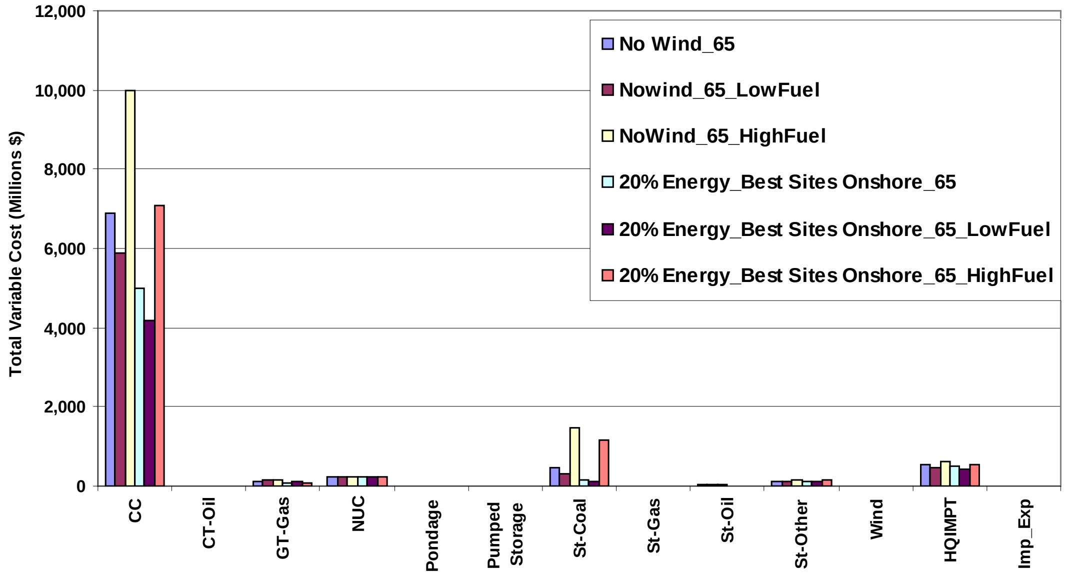


Figure 5–108 Fuel price impact on ISO-NE total variable cost by type

Figure 5–109 shows the annual load weighted average LMP for ISO-NE. In the No Wind case, the decrease in fuel costs under the low fuel scenario decreases the price, but only partially counteracts the price increase due to the carbon policy. The high fuel scenario raises prices, and in combination with the carbon policy, results in the highest average LMP's. The Onshore cases show similar results.

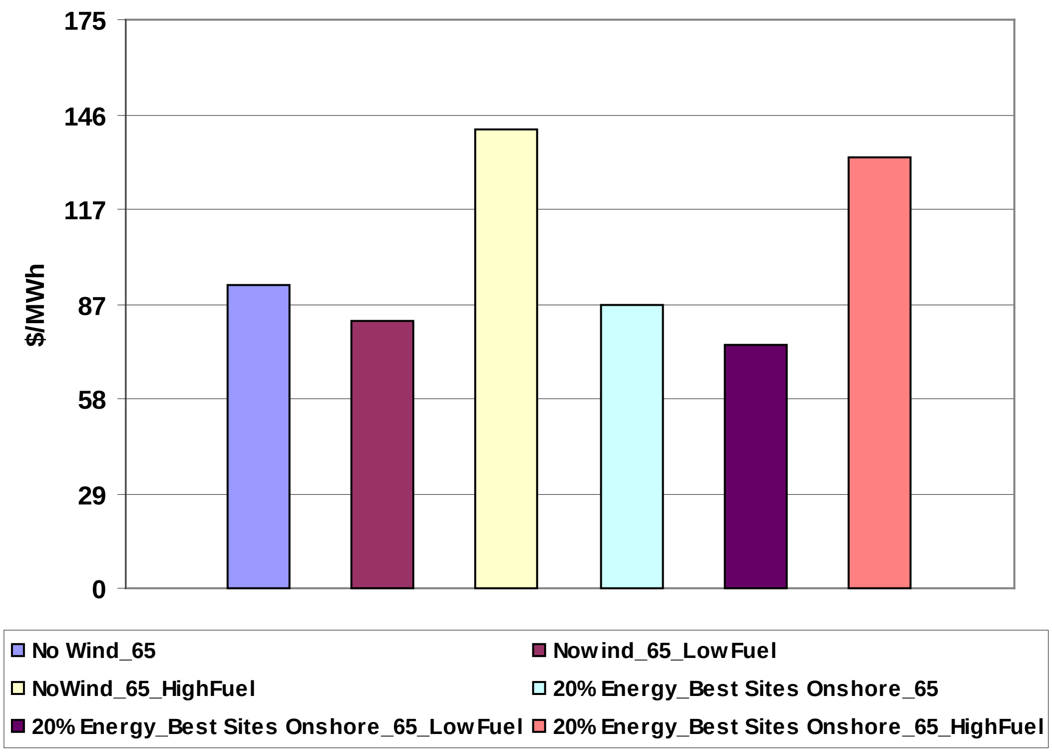


Figure 5–109 Fuel price impacts on annual load weighted average ISO-NE LMP

5.3.3 *Load Forecast Uncertainty Sensitivity*

The following sensitivity looked at how including an imperfect load forecast with a S-o-A wind forecast for the ISO-NE system would change operations. This was done only for ISO-NE. The other regions had perfect knowledge of the hourly load but used a S-o-A wind forecast. The 2006 ISO-NE load forecast error was used as an adder to the 2006 RSP zonal extrapolated load for the commitment phase of the MAPS model. The load forecast error was determined by comparing the 2006 ISO-NE day-ahead load forecast to the 2006 Actual load[73]. The actual 2006 extrapolated load and wind was used for the dispatch.

It is important to analyze the effect an imperfect load forecast has on the system as well as an imperfect wind forecast. Forecasts are not perfect and contain errors. The load forecast error might be additive or balance out the wind forecast error. Therefore introducing an imperfect load forecast increases the complexity of operating the system.

This analysis assesses the impacts of load forecast error combined with wind forecast error and the resulting impacts. Figure 5–110 shows duration curves for the 2020 load forecast, actual load, wind forecast, actual wind, the net load forecast, and actual net load that were used in the simulation.

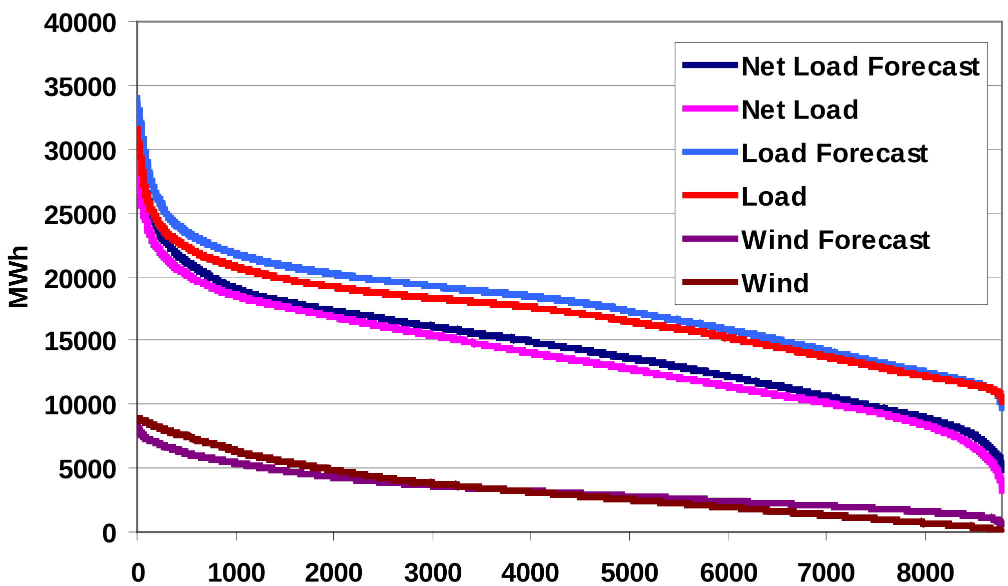


Figure 5–110 20% Energy_Best Sites Onshore annual load and wind duration comparison

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[73] http://www.iso-ne.com/markets/hstdata/znl_info/hourly/2006_smd_hourly.xls

Figure 5–111 shows, for the month of April, the hourly load forecast, actual load, wind forecast, and actual wind. The load forecast is higher during most the peak hours, but the wind forecast is typically lower. The higher peak load forecast likely represents a bias applied by the ISO to reliably operate the system during these times.

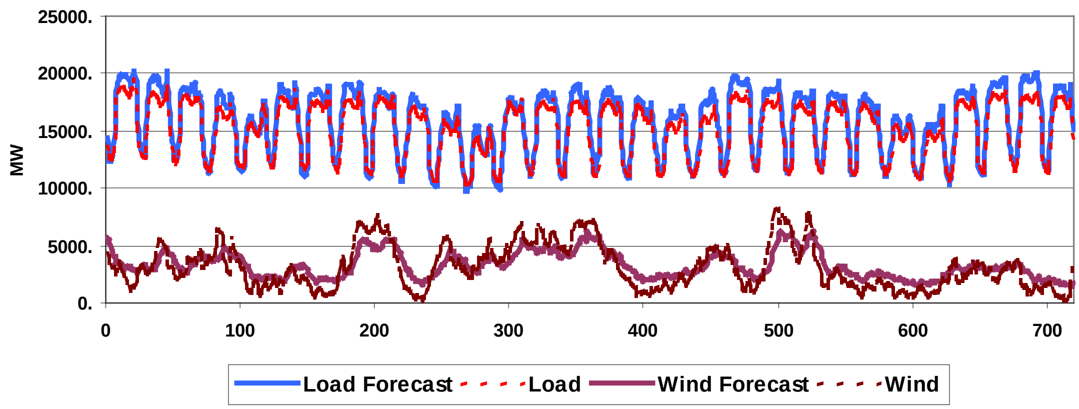

Figure 5–111 20% Energy_Best Sites Onshore annual load and wind comparison, month of April

Figure 5–112 compares the generation by type for ISO-NE for the No Wind, the No Wind using the (imperfect) load forecast, 20% Energy_Best Sites Onshore with S-o-A wind forecast, and 20% Energy_Best Sites Onshore with S-o-A wind forecast and (imperfect) load forecast. The load forecast impacts the CC generation. As shown in Figure 5–111, the load forecast is typically higher than the actual load. This causes an over commitment of generation, primarily CC units. The effect of the load forecast causes an additional 12 GWh of wind curtailment. This equates to 0.04% of the annual wind energy produced in the 20% Energy_Best Sites onshore case with load forecast error.

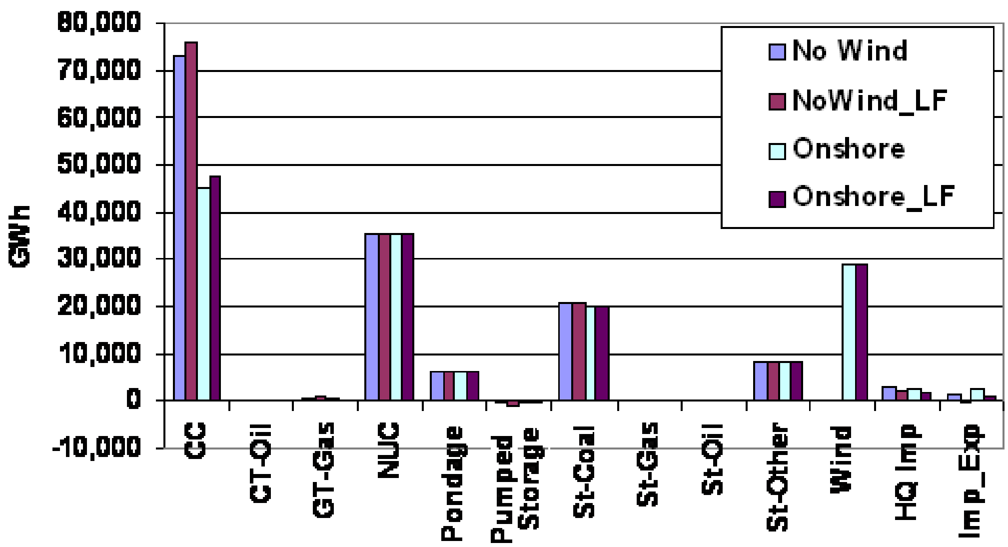

Figure 5–112 Load forecast impact on ISO-NE generation by type

The over commitment of the CC units impacts the total ISO-NE emissions as seen in Figure 5–113. The NOx and CO2 are higher in the load forecast cases than the cases without load forecast uncertainty (i.e. the cases with perfect load forecasts). The over commitment of the CC generation backs the CC units down to lower operating points during the dispatch to a less efficient operating point on their average heat rate curve and therefore produce higher emission amounts.

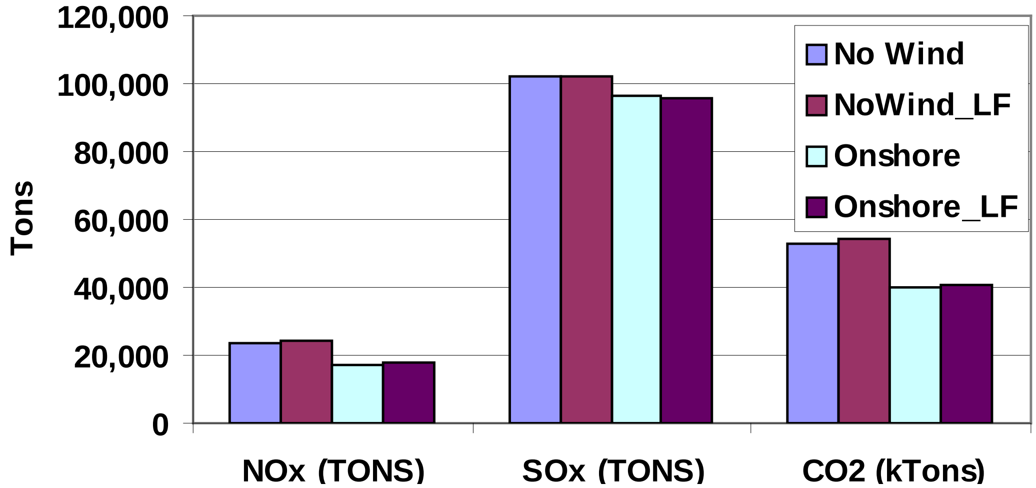

Figure 5–113 Load forecast impact on ISO-NE emissions

Figure 5–114 compares the load-weighted average LMP for ISO-NE. The price is lower in the cases that have load forecast error built into them. Although CC units are backed down to a less efficient lower operating point, the incremental cost is lower. Therefore, average LMP is reduced.

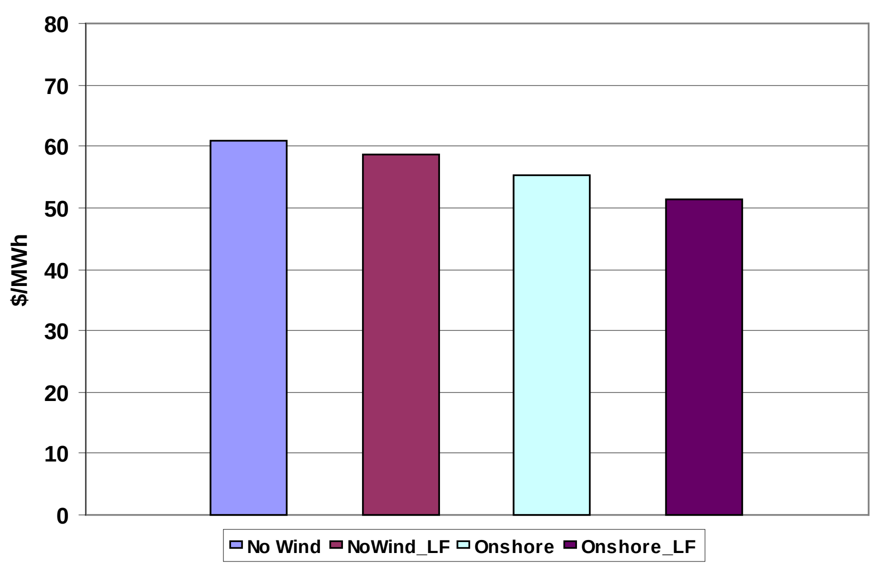

Figure 5–114 Load forecast impact on annual load weighted average ISO-NE LMP

The revenue by type is reflected in Figure 5–115. The revenue is lower for most of the generation. The CCs revenue is slightly higher because of the increased operation.

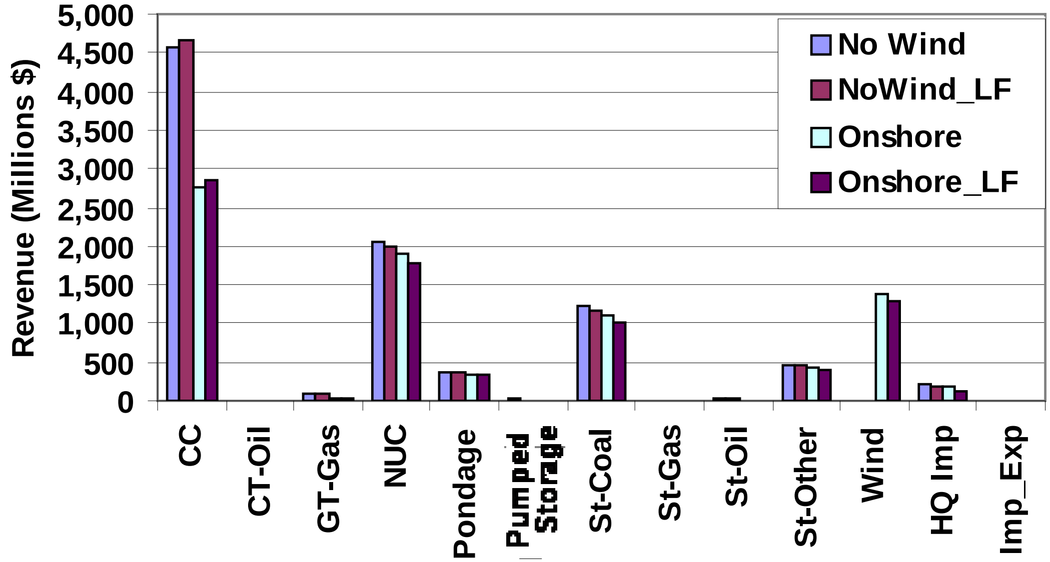

Figure 5–115 Load forecast impact on ISO-NE revenue by type

Figure 5–116 compares the value of the wind for the case with and without forecast error. The value is also included for a case with perfect load knowledge and a perfect wind forecast. With perfect knowledge, the wind has a value of $58/MWh to $55/MWh when a load forecast error is assumed and a S-o-A wind forecast is used.

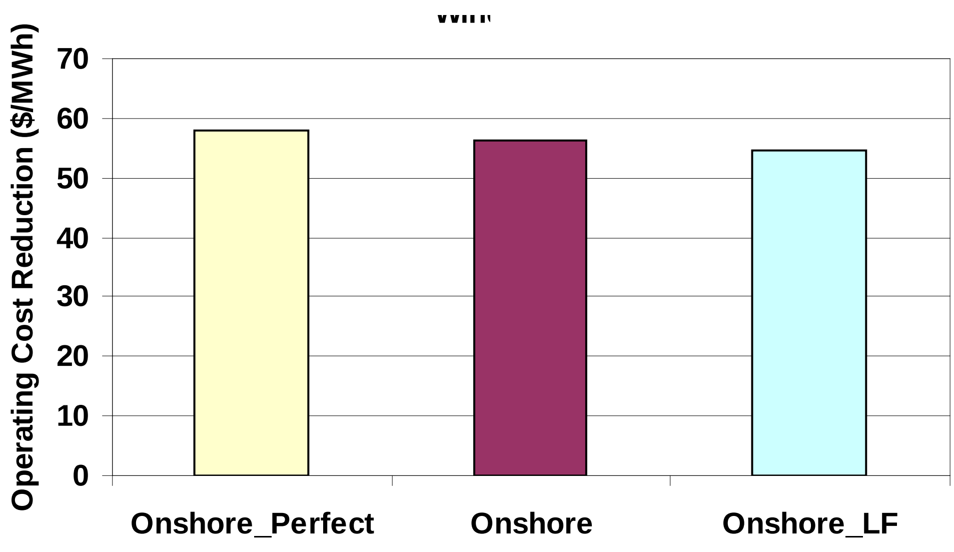

Figure 5–116 Load forecast impact on ISO-NE operating cost reduction per MWh of wind generation

5.3.4 Maritimes Interface Expansion Sensitivity

The following section compares the impact of quadrupling the import/export capability from the Maritimes to ISO-NE. The Maritimes to ISO-NE interface was raised from 500 MW/-1000 MW to 2000 MW/-4000 MW. The 20% Energy_Best Sites Maritimes scenario was evaluated.

Figure 5–117 shows the generation by type for the No Wind, No Wind with quadruple import capability from the Maritimes, 20% Energy_Best Sites Maritimes, and 20% Energy_Best Sites Maritimes with quadruple import capability from the Maritimes. The comparison of the No Wind and 20% Energy_Best Sites Maritimes scenarios show the increased interface limits result in a small change in imports. It is important to note that the Maritimes wind generation was counted in the "wind" category and not the "imports." Combined Cycles are displaced within New England in the No Wind sensitivity case to account for the additional imports. Gas turbines also run slightly more in the No Wind sensitivity as NE exports more to the Maritimes in the winter months during which the Maritimes has its peak load season. The 20% Energy_Best Sites Maritimes with increased limits results in ISO-NE importing slightly more energy than the 20% Energy_Best Sites Maritimes case in addition to the wind.

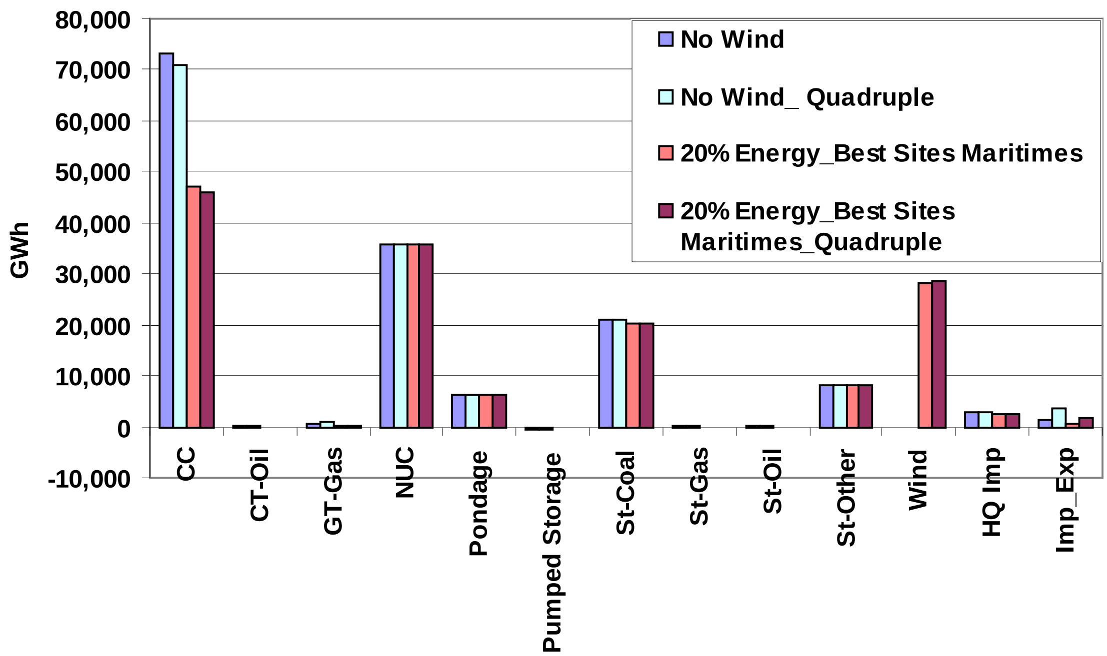

Figure 5–117 Maritimes interface expansion impact on ISO-NE generation by type

The revenue by type comparison is shown in Figure 5–118. Due to the increased seasonal exports in the No Wind case, ISO-NE prices are slightly higher on an annual basis. With the change in interface flows, NB prices are reduced, also reducing total system cost. These higher prices in ISO-NE result in higher revenues for all types of generation. A similar result can be seen for the 20% Energy_Best Sites Maritimes cases.

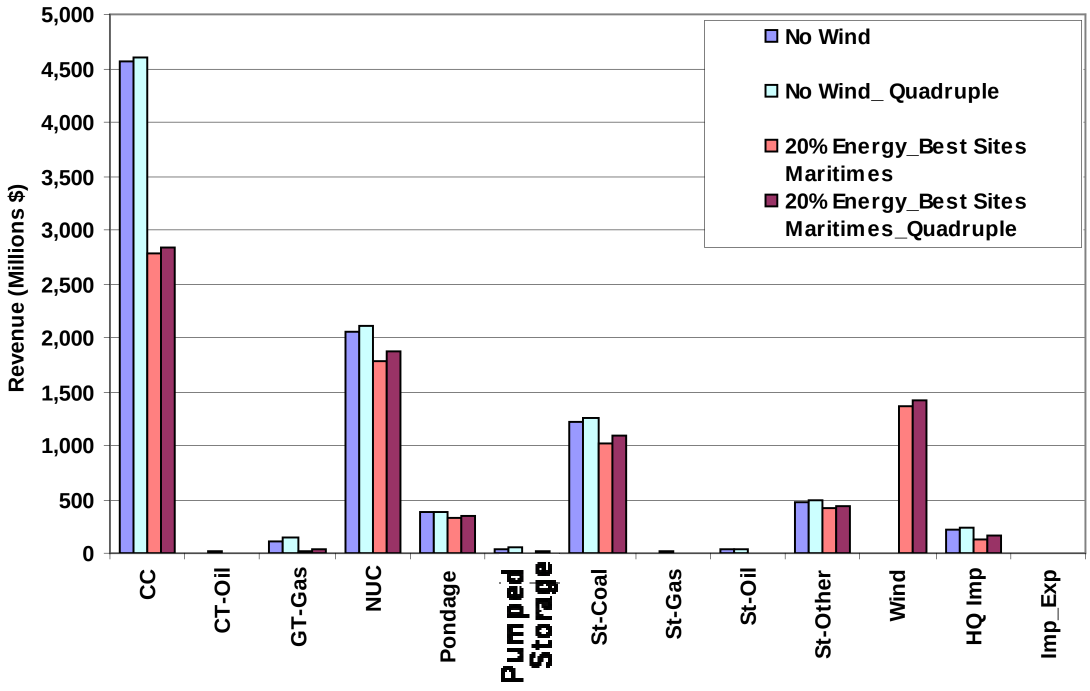

Figure 5–118 Maritimes interface expansion impact on ISO-NE revenue by type

Figure 5–119 compares the value of the wind generation between the original and quadruple import/export capability scenario. The value is similar between the two scenarios; however, wind becomes slightly more valuable, about $1/MWh more valuable.

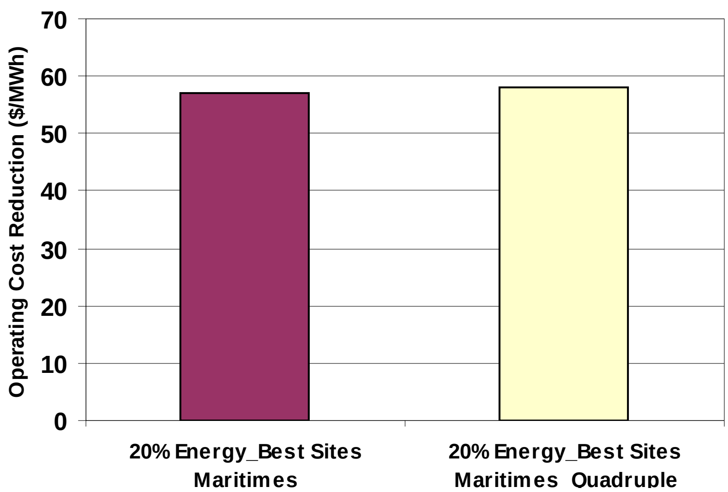

Figure 5–119 Maritimes interface expansion impact on ISO-NE operating cost reduction per MWh of wind generation

Quadrupling the interface limits from ISO-NE to the Maritimes reduces wind curtailment from 328.65 GWh in the 20% Energy_Best Sites Maritimes to 11.08 GWh in the 20% Energy_Best Sites Maritimes_Quadruple scenario.

Figure 5–120 compares the flow duration on the ISO-NE to Maritimes interface for the four scenarios. Note that negative flow, is flow from the Maritimes to ISO-NE. The No Wind with quadruple import/export capability has more exports to the ISO-NE and less imports to Maritimes. The 20% Energy_Best Sites Maritimes with quadruple interface limits exports more than 20% Energy_Best Sites Maritimes scenario to ISO-NE.

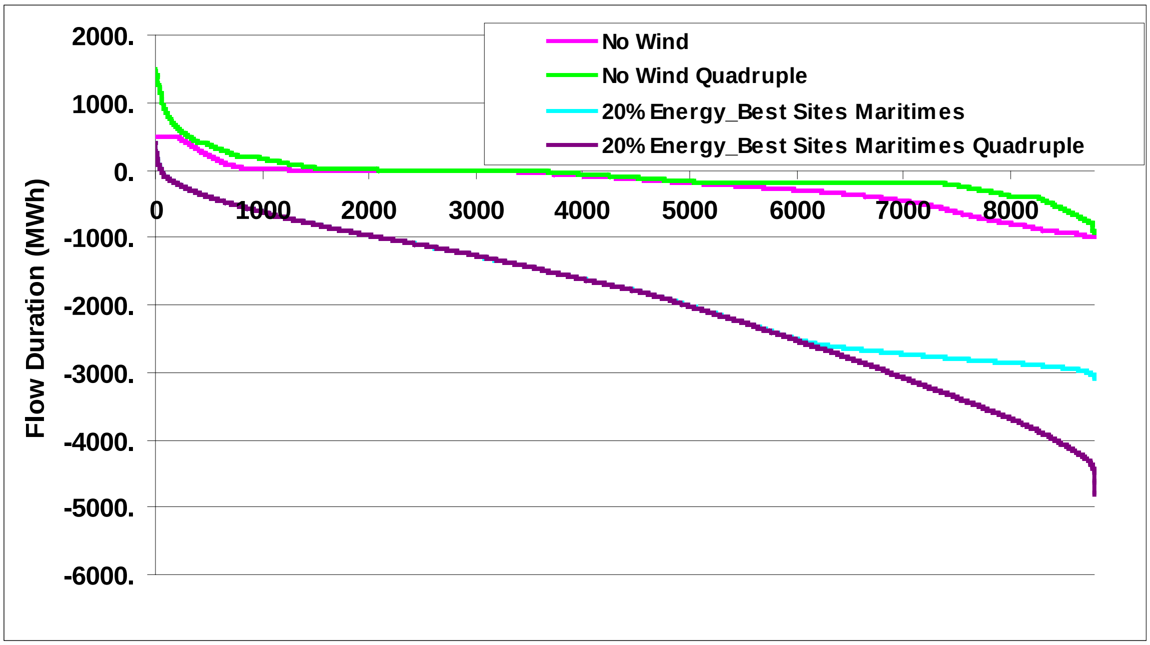

Figure 5–120 ISO-NE to Maritimes interface flow comparison

Quadrupling the interface limits to the Maritimes has minimal impact on the ISO-NE system. The cost of the transmission expansion would likely out-weigh the impacts.

5.3.5 ISO-NE Interface Sensitivity

The following section compares the impact of doubling the import/export capability from NY, Maritimes, and Hydro Quebec to ISO-NE. The NY to ISO-NE AC interface was raised from +-1,600 MW to +-3,200 MW. The Maritimes to ISO-NE interface was raised from 500 MW/-1000 MW to 1000 MW/-2000 MW. The HQ Import capacity was increased from 1,600 MW to 3,200 MW.

Figure 5–121 shows the generation by type for the No Wind, No Wind with double import capability, 20% Energy_Best Sites Onshore, and 20% Energy_Best Sites Onshore with double import capability. The comparison of the No Wind and 20% Energy_Best Sites Onshore scenarios show the net increased imports displace the CC generation. The HQ imports roughly double. In the No Wind with double import capability, the imp/exp flips. The 20% Energy_Best Sites Onshore with double import capability the imp/exp remains roughly the same as the 20% Energy_Best Sites Onshore.

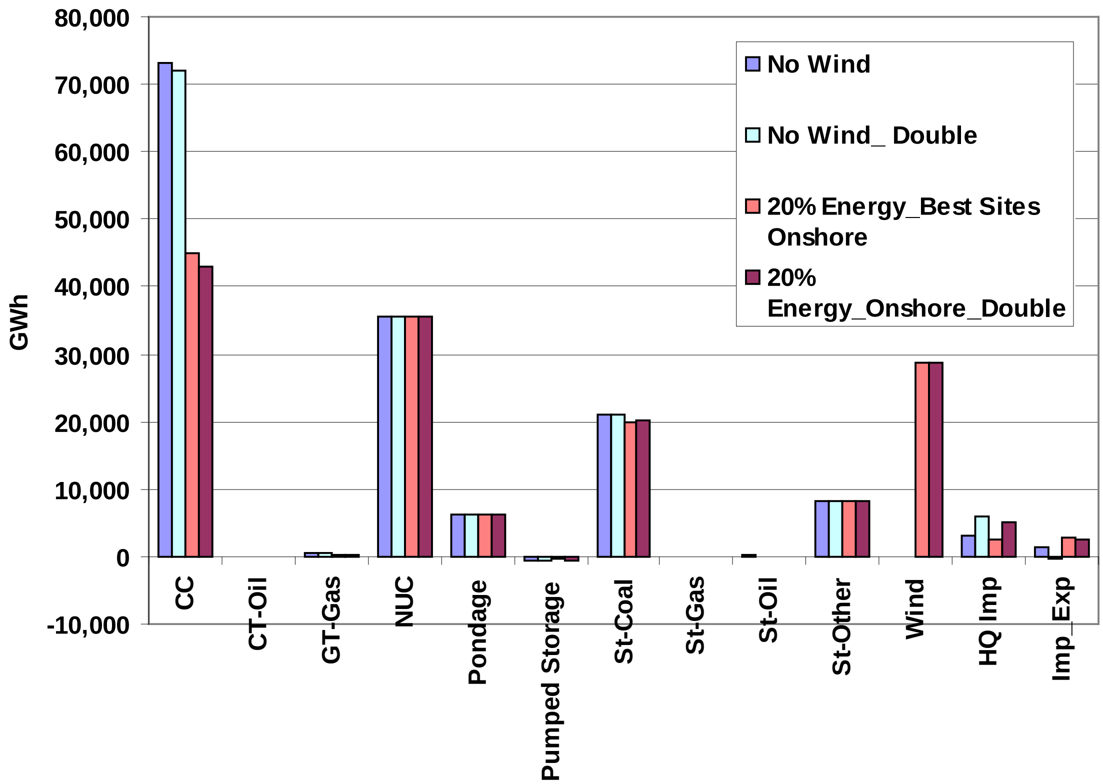

Figure 5–121 Interface expansion impact on ISO-NE generation by type

The revenue by type comparison is shown in Figure 5–122. As expected, the largest decrease in revenue occurs to the CC generation. This is because of the displacement shown in Figure 5–121.

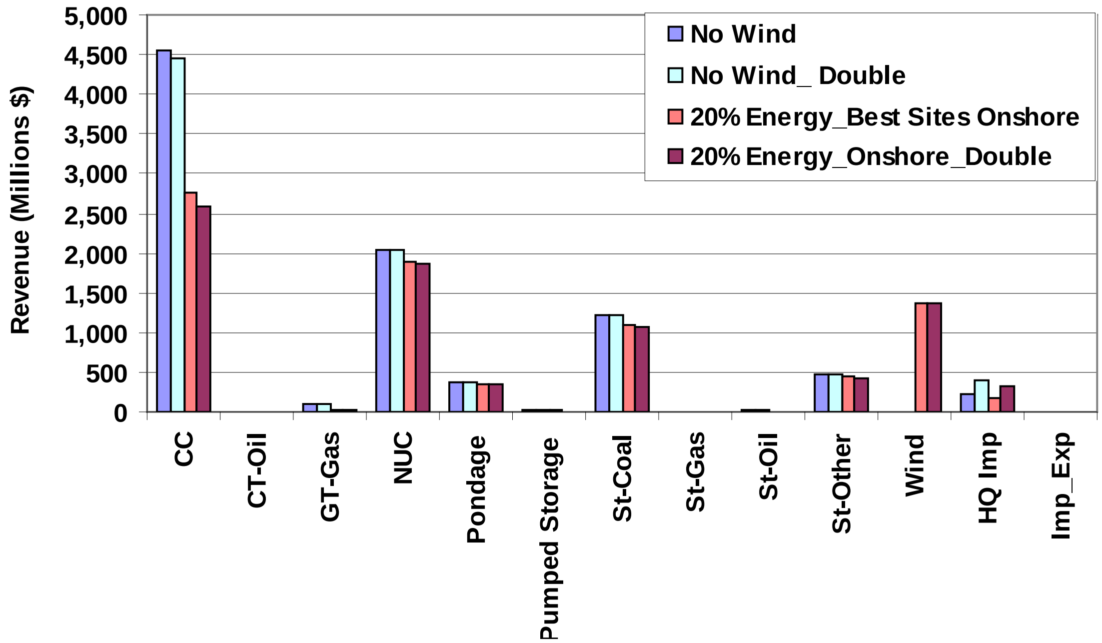

Figure 5–122 Interface expansion impact on ISO-NE revenue by type

Figure 5–123 compares the value of the wind generation between the original and double import/export capability scenario. Doubling the import capability reduces the operating cost for ISO-NE slightly more and therefore adds more value to the wind, about $1/MWh.

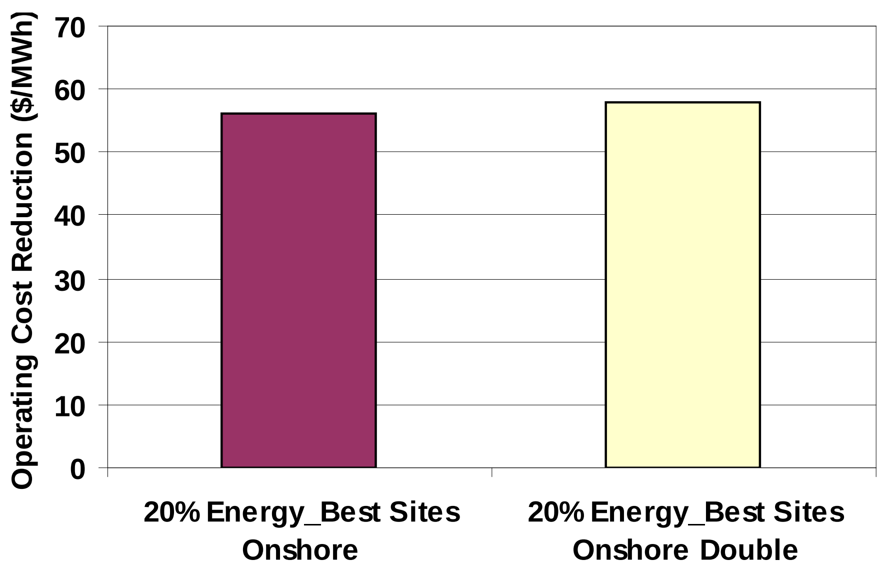

Figure 5–123 Interface expansion impact on ISO-NE operating cost reduction per MWh of wind generation

Figure 5–124 compares the flow duration on the ISO-NE to Maritimes interface for the four scenarios. The No Wind with double import/export capability has more exports to the Maritimes and less imports to ISO-NE. The two 20% Energy_Best Sites Onshore are similar.

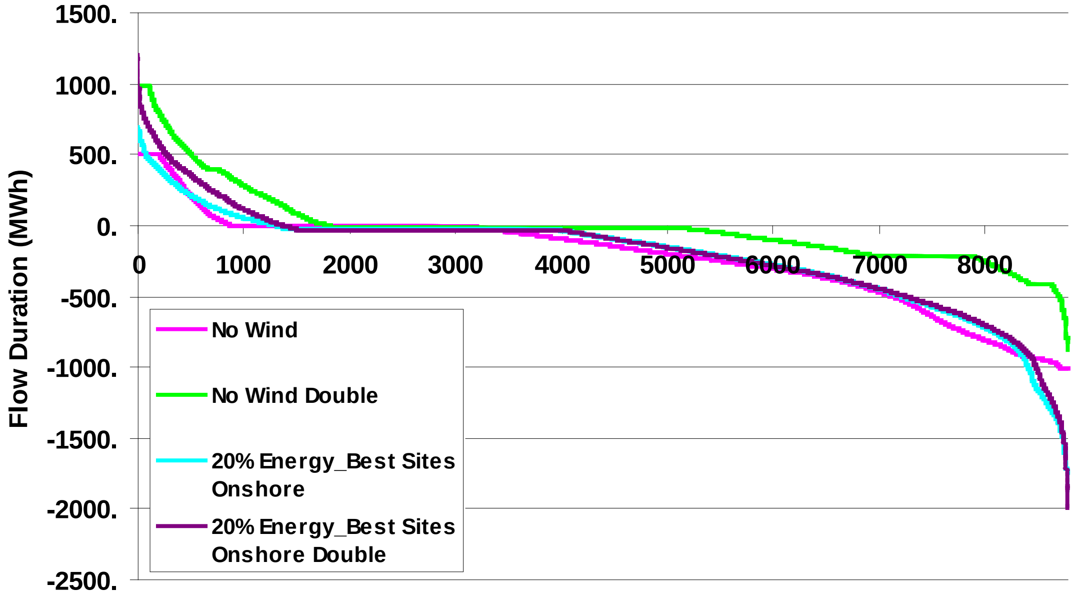

Figure 5–124 ISO-NE to Maritimes Interface flow comparison

Figure 5–125 compares the flow duration on the ISO-NE to NY interface for the four scenarios. There is practically no impact by doubling the import/export capability.

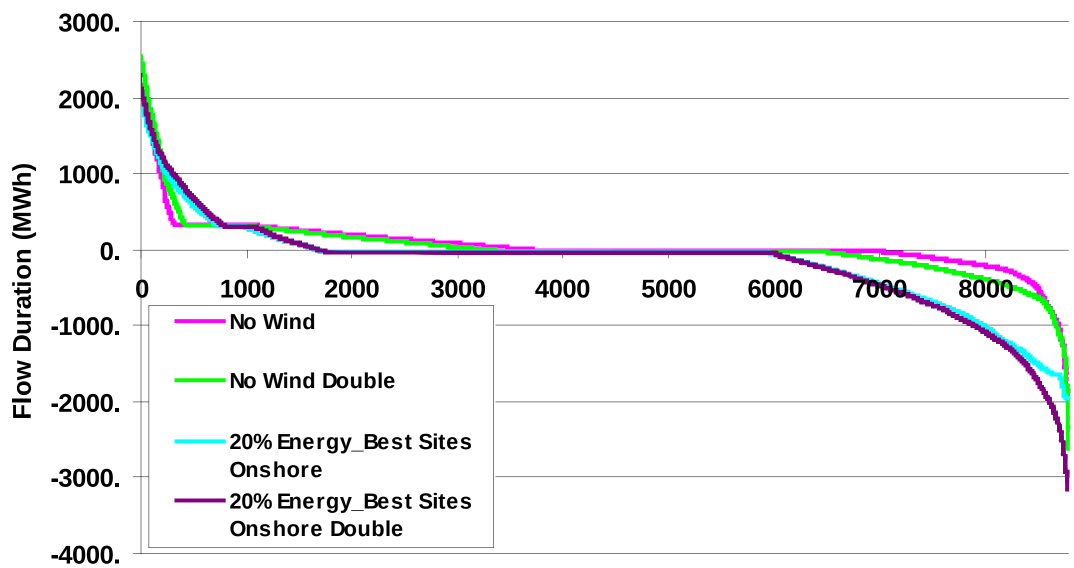

Figure 5–125 ISO-NE to NYISO Interface flow comparison

Figure 5–126 compares the generation duration of the HQ IMP generator for the four scenarios. The generation doubles in comparison of the scenarios.

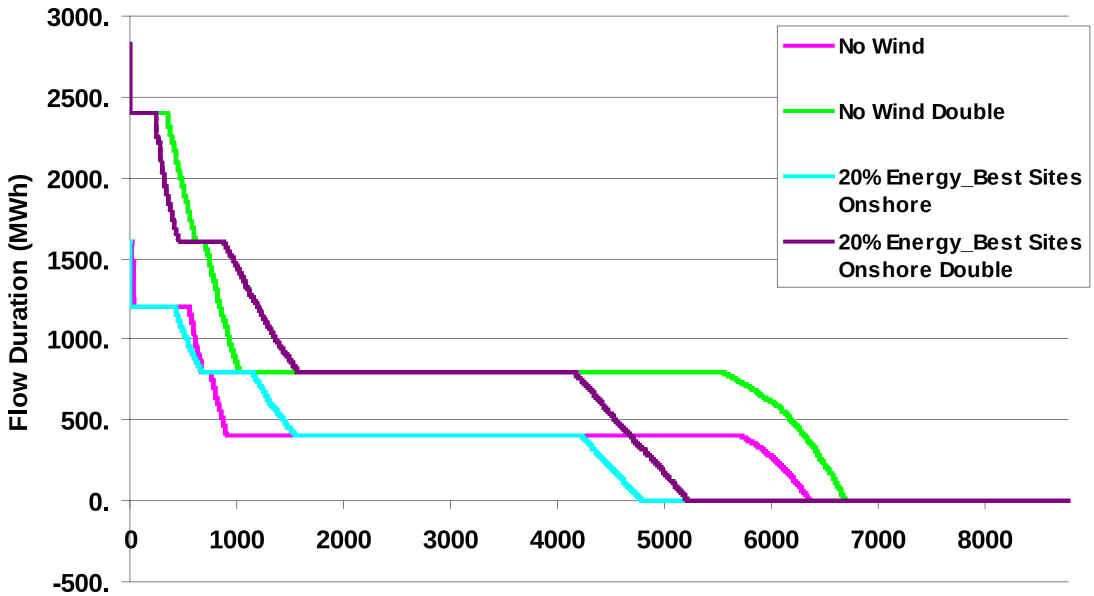

Figure 5–126 HQ Imports comparison

5.4 Operational Analysis Observations and Conclusions

From an hourly operational analysis viewpoint, integration of high levels of wind into the assumed ISO-NE system is feasible and produces energy values in the range of $50 – $54 per megawatt hour of wind energy generated; however, these results are based on numerous assumptions and hypothetical scenarios developed for modeling purposes only. The reduction in system-wide variable operating cost is essentially the marginal cost of energy, which should not be equated to a reduction in $/MWh for market clearing price (i.e. Locational Marginal Prices--LMPs). Low-priced wind resources could displace marginal resources, but that differential is not the same as reductions in LMPs.

As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and therefore should not be considered the primary basis for evaluating the different scenarios.

The assumed ISO-NE generation portfolio appears to be compatible with the studied penetrations of wind. Even up to 24% energy there were no significant operating issues observed, like running out of ramp/range up capability. There were few hours where the ramp/range went to 0, roughly 16 hours. Potentially, this can be addressed by curtailing wind. The generation displacement in ISO-NE is primarily combined cycles for all levels of penetration with some coal displacement occurring at higher penetrations. There were relatively small changes in PSH utilization across all levels of penetration. 20% wind penetration also had the following impacts:

- NOx - ~6,000 tons
- SOx - ~4,000 tons
- CO2 - ~12 million tons
- LMP – $5 to $11/MWh

For a given penetration of wind energy, differences in the locations of wind plants had very little effect on overall system performance. For example, the system operating costs and operational performance were roughly the same for all the 20% wind energy penetration scenarios analyzed. This is primarily because all the wind layout alternatives had somewhat similar wind profiles (since all of the higher penetration scenarios included the wind generation from the Full Queue), there was no significant congestion on the assumed transmission systems, and the assumed system had considerable flexibility, which made it robust in its capability of managing the uncertainty and variability of additional wind generation across and between the studied scenarios.

The individual metrics (e.g., prices, emissions) are useful in comparing scenarios, but should not be used in isolation to identify a preferred scenario or to predict actual future results.

There were very few hours when transmission congestion was an issue given assumed build-outs. Refinement of transmission build outs should be evaluated. The investment costs required for both the wind generation and transmission expansion were not considered in this analysis and will be an important factor in deciding which of the development paths suggested by the scenarios might be pursued. Some scenarios that showed the least transmission congestion also required the greatest investment in transmission, so congestion results should not be evaluated apart from transmission expansion requirements. Some scenarios that showed the greatest reductions in LMPs and generator emissions also used wind resources with low capacity factors, which would result in higher capital costs.

The impact on generation displacement and revenue reduction increased gradually with increasing wind penetration from the 2.5% through the 24% level. There appeared to be no major step change in the impact across this range.

The existing ISO-NE generation fleet is dominated by natural-gas-fired resources, which are potentially very flexible in terms of ramping and maneuvering. As shown in the upper left pie chart of Figure 5–127, natural gas resources provide about 50% of total annual electric energy in New England assuming no wind generation on the system. Wind generation would primarily displace natural-gas-fired generation since gas-fired generation is most often on the margin in the ISO-NE market. The pie charts show that as the penetration of wind generation increases, energy from natural gas resources is reduced while energy from other resources remains relatively constant. At a 24% wind energy penetration, natural gas resources would still be called upon to provide more than 25% of the total annual energy (lower right pie chart). In effect, a 24% wind energy scenario would likely result in wind and natural-gas-fired generation providing approximately the same amount of energy to the system, which would represent a major shift in the fuel mix for the region. It is unclear, given the large decrease in energy market revenues for natural-gas-fired resources, whether these units would be viable and therefore continue to be available to supply the system needs under this scenario. Revenue reduction for units not being displaced by wind energy is roughly 5%-10%, based on lower spot prices. For units that are being displaced, their revenue losses are even greater. This will likely lead to higher bids for capacity and may lead to higher bids for energy in order to maintain viability. The correct market signals must be in place in order to ensure that an adequate fleet of flexible resources is maintained. During peak hours, wind has a much lower than nameplate capacity value, even though up to 24% of energy is produced. Capacity value is discussed further in Chapter 6 of this report.

Incorporating the day-ahead wind forecast, even if it is imperfect, in the commitment decision was shown to make a significant impact at all levels of penetration. Analysis performed for the NEWIS indicates that these effects, and hence the case for implementation of a wind power forecast, grows as wind power penetrations increase.

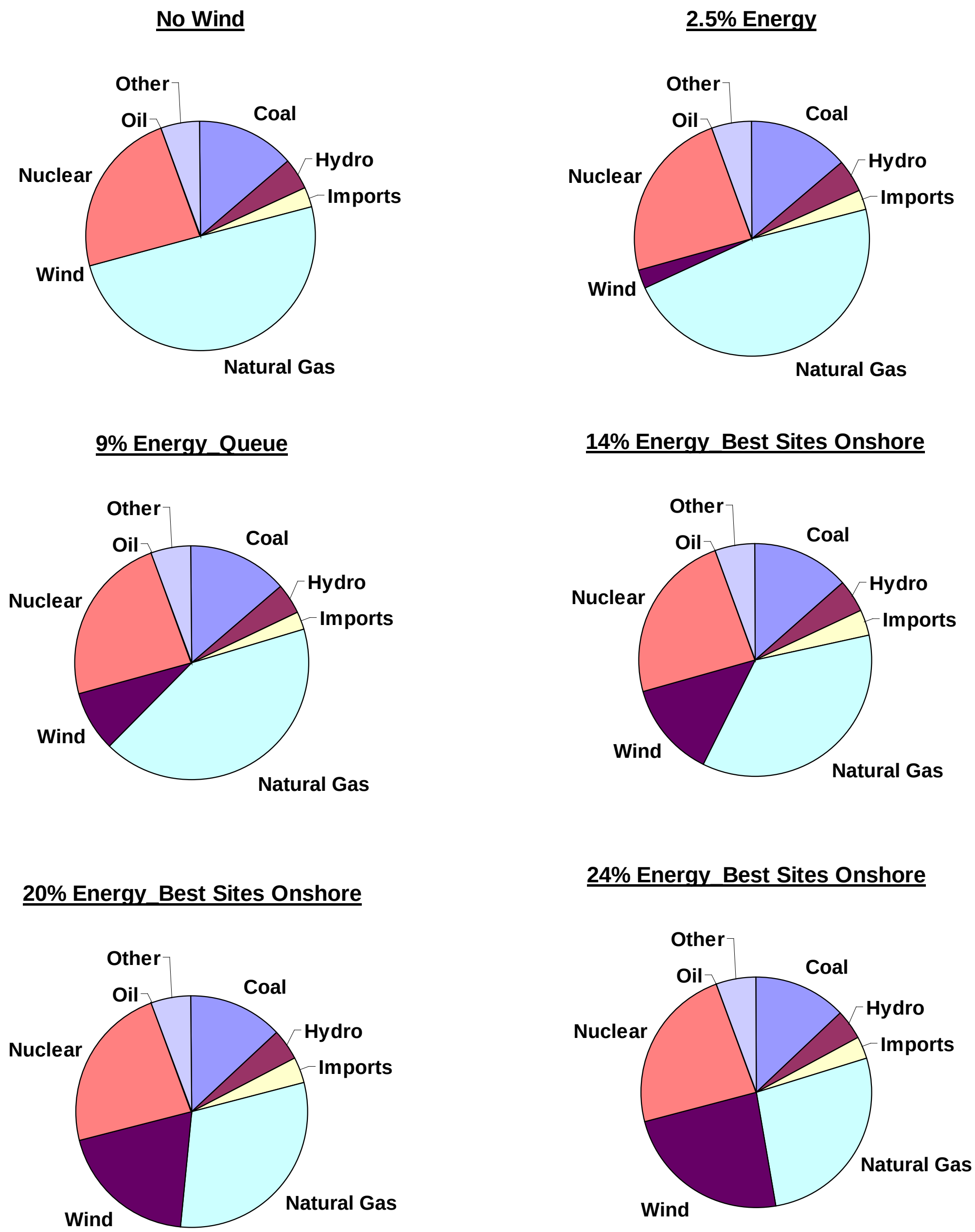

Figure 5–127 Annual Energy from ISO-NE Generation Fleet with Increasing Wind Energy Penetration.

6 Reliability Analysis

6.1 Introduction

A capacity value analysis was performed on the various wind generation scenarios being examined in New England. As with the operational analysis, multiple yearly wind profiles and load shapes were considered. The variation in results between the different annual patterns tends to be more pronounced in the capacity valuations as compared to the production simulations because the capacity value is much more a function of the wind performance for a few critical hours and days whereas the production value is a function of the generation throughout the year. This analysis considered variations in wind penetration, scenario layout and annual load shapes and wind profiles for all of the wind scenario aggregations. The capacity values were developed for each aggregation and no attempt was made to isolate the capacity value of wind resources by individual geographic area. It is also important to differentiate the “capacity value” from the similar sounding “capacity factor.” The “capacity factor” is the annual energy production divided by the nameplate rating and the number of hours in the year. The capacity factors for the individual wind plants ranged from 27% to 47% based on their location. The “capacity value” is the expected amount of capacity that can be counted on to meet the installed capacity requirements needed to satisfy the system reliability criteria. As will be discussed later, the capacity values are often approximated by the average capacity factors during just the peak load hours. The capacity values for the various scenarios examined ranged from 20% to 36%.

Figure 6–1 shows a summary of how the results vary for a range of penetrations and annual patterns for the "Onshore" scenarios. (All of the scenarios at the 14% and 20% level will be examined in more detail later in this chapter.) The capacity values, in MW, are shown for each year of the analysis, along with the three-year average value. The red squares show the average capacity value as a percent of the installed nameplate capacity (right hand scale). The average capacity values decrease from 36% for the 2.5% penetration scenario down to 20% for the 20% penetration scenario.

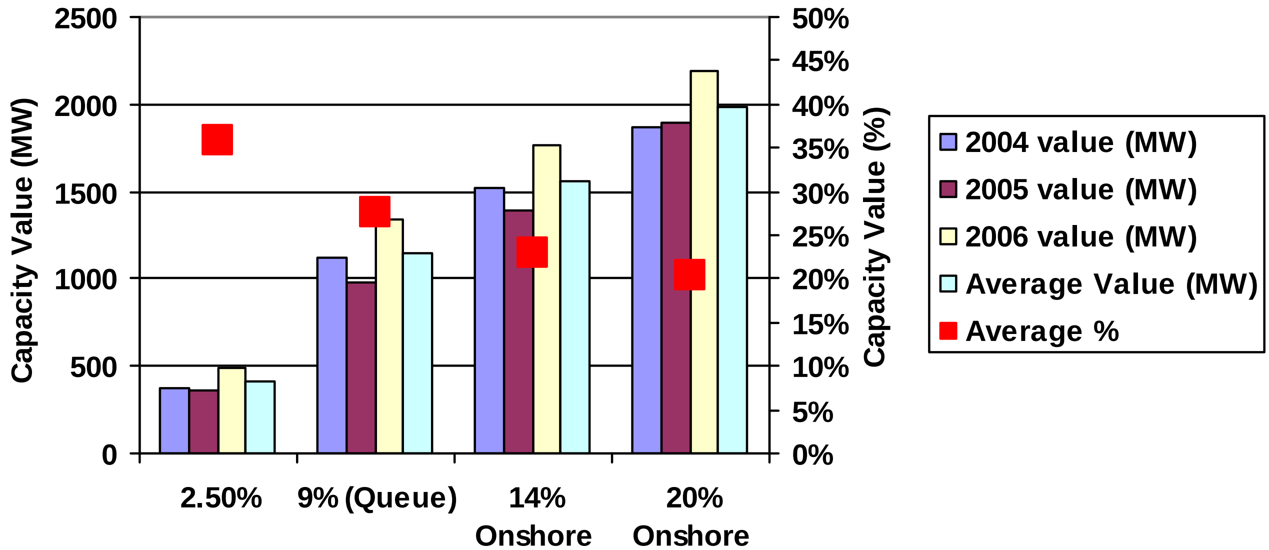

Figure 6–1 Capacity value results

The variability from year to year is typical of results seen in other wind integration studies (such as the New York and the Western Wind and Solar Integration Study discussed previously), as is the decrease in value with increasing penetrations. There are two primary causes for the decreasing values. The first is just saturation. The wind generation is not constant throughout the day or the year. Although there is variability in the generation, there are also patterns that emerge. As increasing amounts of generation are added with similar patterns, the original "peak hour" of the day has less and less impact on the daily risk while other hours, when the wind may not be as strong, become relatively more prominent in the calculation. Diversity of locations will help mitigate this effect, but similar diurnal patterns will exist. The second reason for the decrease is that the best sites were added first. The wind plants were ranked based on decreasing capacity factor. As higher penetrations were required, the capacity factors of the plants added decreased.

6.2 Methodology

A Loss of Load Expectation (LOLE) analysis was performed for the proposed 2020 ISO-NE system in order to determine the Effective Load Carrying Capability (ELCC) of the wind scenarios. The model used was the GE Multi-Area Reliability Simulation (MARS) program. Details of the model are discussed in Appendix D. The data used is the same as for the production simulation analysis with the following exceptions. In order to fully reflect the value within New England the neighboring systems were ignored. In addition, transmission constraints within New England were ignored. In this way, the capacity value of the wind generation will purely be a function of the hourly wind generation patterns, hourly load shapes and the size and characteristics of the balance of thermal and hydro generation within New England. For the 2004-based load and wind profiles, this resulted in an LOLE of 0.575 days/year. This is larger than the ISO-NE planning criteria of 0.1 days/year because, among other factors, the interconnection to neighboring systems and emergency operating procedures were ignored.

Increasing amounts of perfect capacity (that is, no planned or forced outages) were then added to the system to produce the results shown in Figure 6–2. As the capacity additions increased, the expected number of outages per year decreased. This then set the framework for the evaluation of the various wind generation scenarios.

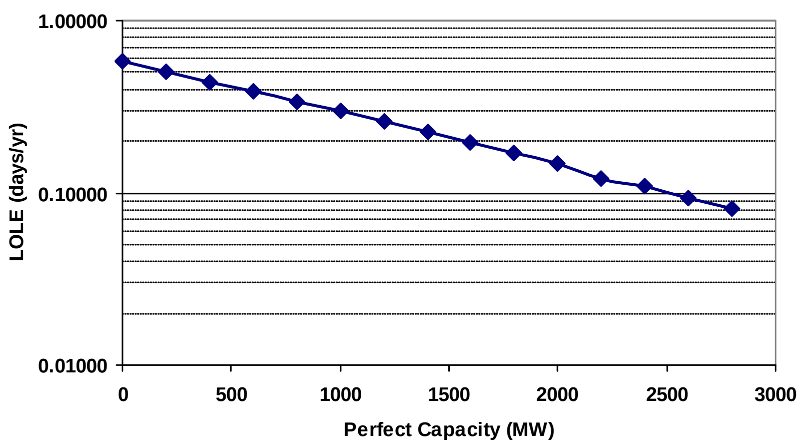

Figure 6–2 Perfect capacity impact for 2004 shapes

As the reliability index was then calculated for each of the scenarios, it could then be plotted on the curve shown in Figure 6–2 and the corresponding value in perfect capacity could be determined. These results are shown in Figure 6–3. The “Base Scenarios” refer to the “No Wind”, “2.5%” and “9 %(Queue)” cases. For example, the 2.5% energy scenario reduced the risk to 0.451 days/year. Interpolating from the curve shows that it would require 370 MW of perfect capacity to achieve the same amount of risk improvement. Therefore, the 2.5% energy scenario has a capacity value of 370 MW. Since this scenario included 1140 MW of nameplate wind capacity then the capacity value was 33% (= 370/1140). Each of the other scenarios was then evaluated and the reliability results are shown in Figure 6–3. Note that the first point off the y-axis corresponds to the 2.5% energy scenario.

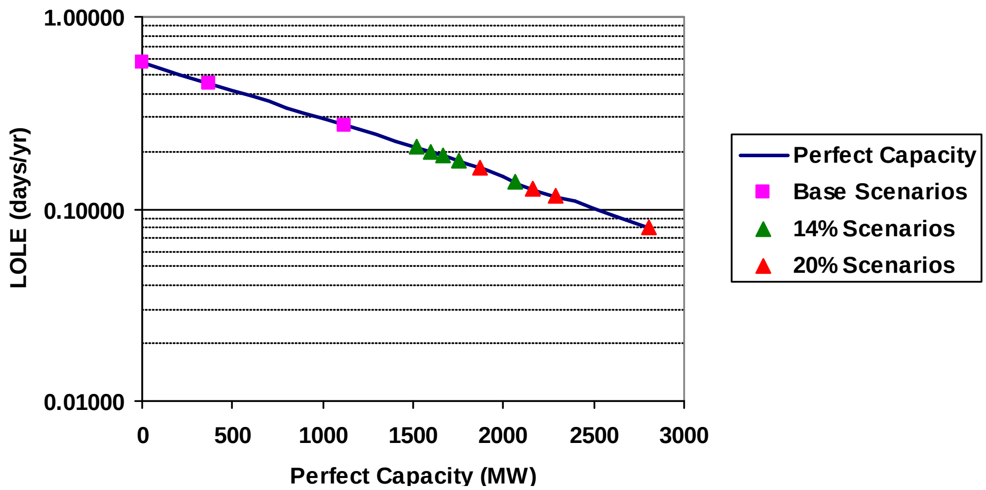

Figure 6–3 LOLE analysis with 2004 based profiles

This analysis was then repeated for each of the annual shapes. The base "perfect capacity" curves are shown in Figure 6–4. Although all three load shapes were adjusted to the same annual peak the starting "no wind" reliability was different due to the underlying shapes. This will be discussed more later in the chapter.

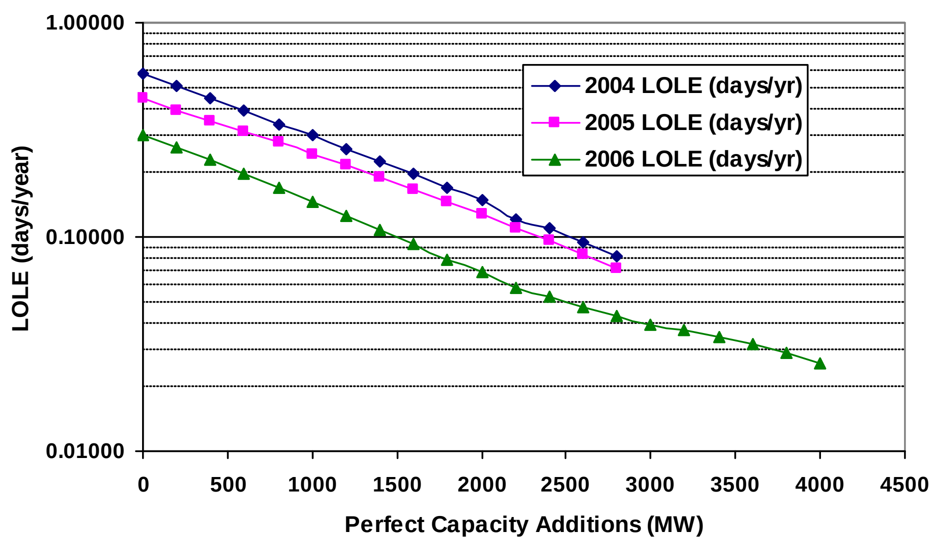

Figure 6–4 Perfect capacity impacts for all three years

6.3 Capacity Value Variation by Scenario

There was only a single scenario layout for the 2.5% and 9% energy cases. However, the 14% energy and 20% energy penetration scenarios considered several different layout alternatives, as has been discussed previously. Because the annual capacity factor varied between the scenario layout alternatives the amount of nameplate capacity also varied. In order to more easily compare the results the capacity values are shown as a percent of the installed capacity rather than as MW values. Figure 6–5 shows the annual and average results for the various scenarios with 14% energy. (Note: the “Best Sites” scenario is also referred to as the “Balance” scenario.) The output from the offshore sites tended to be more aligned with the load profile, and therefore had better capacity values. The text line under the chart shows the percent of offshore nameplate capacity in each scenario. The scenarios were ranked in order of increasing offshore percentage to highlight the impact. Although all scenarios delivered 14% wind energy the capacity values ranged from roughly 20% to 40%.

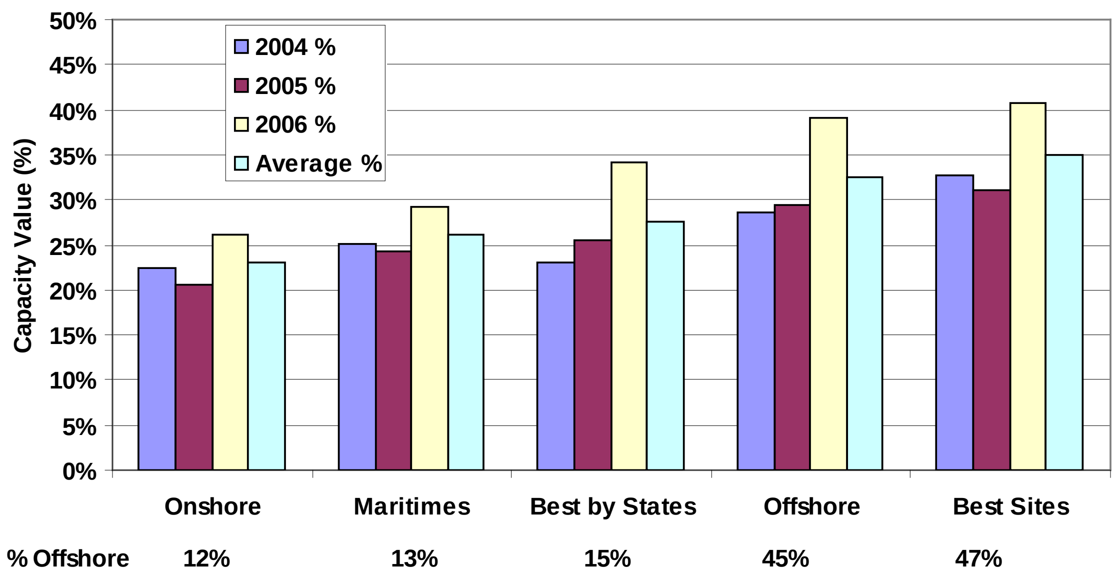

Figure 6–5 Capacity value (% of nameplate) for 14% scenarios

Figure 6–6 shows similar results for the 20% energy scenarios. Although the Maritime scenario only had 9% of the energy from offshore locations the wind profiles were more like the offshore patterns due to scenario layout largely along the coastal area. It can be seen that the capacity value varies for the different scenario layouts but also from year to year for the same scenario. Figure 6–7 combines the 14% and 20% results for easy comparison.

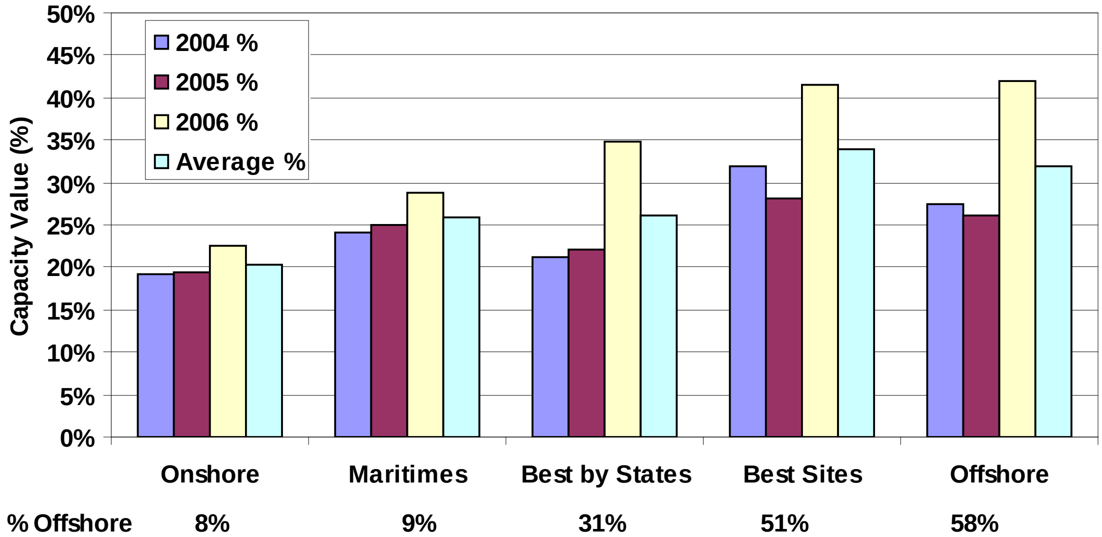

Figure 6–6 Capacity value (% of nameplate) for 20% scenarios

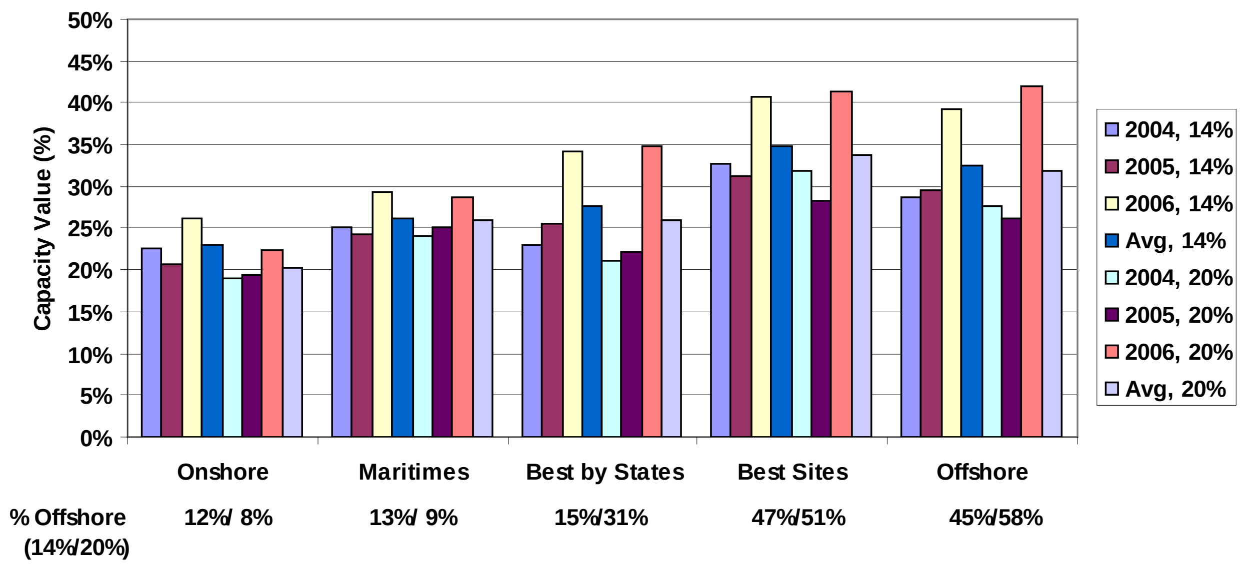

Figure 6–7 Capacity value (% of nameplate) for 14% and 20% scenarios

6.4 Capacity Value Variation by Shape Year

The capacity value of variable generation is a function of the alignment of the load and wind shapes. While there is a definite seasonal and diurnal shape to the wind generation, it is not clear how tightly it is correlated to loads, therefore it may be useful to permute the available wind and load profiles to see how much the coincidence of the load and wind contributed to the overall result. Figure 6–8 matches each of the load shapes to each of the wind profiles. The 2006 wind profile gave similar results for all three load shapes but the other two wind profiles produced capacity values that varied by almost a factor of two for different load shapes. This would indicate that the 2006 wind profile tended to have relatively consistent wind throughout the peak load periods while the other two wind profiles managed to match the peak load days in some years but not in others.

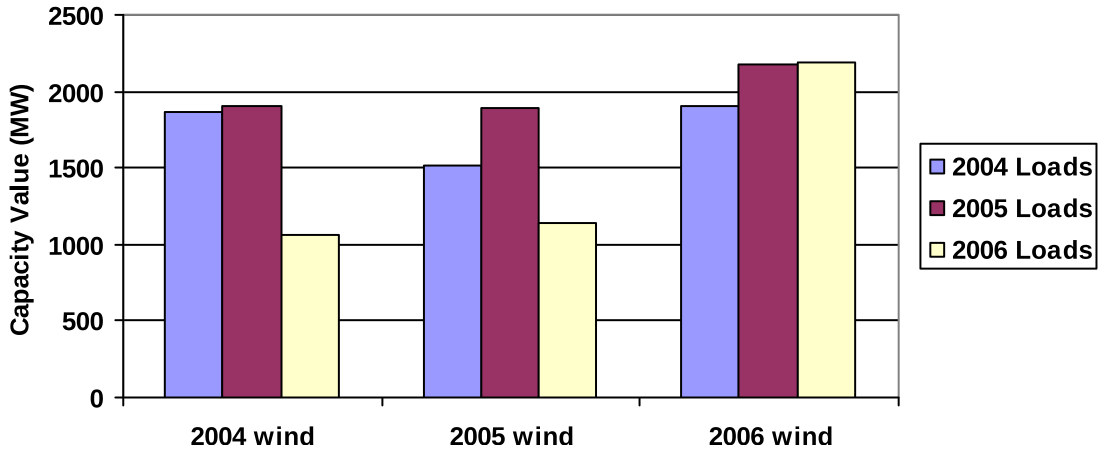

Figure 6–8 Impact of load and wind shapes - capacity values for 20% onshore scenario

Although the system risk comes from more than just the peak day of the year it is often useful to see what is happening on that day. Figure 6–9 shows the load shapes for the three years and the generation from the 20% Onshore and Offshore scenarios. The load profiles are quite similar but the wind profiles are significantly different. Some of the key statistics from this figure and the peak load hour are listed in Table 6–1. The aggregate scenario wind generation during the peak load hour ranges from 10% of nameplate for the 2004 Onshore case to 65% for the 2006 Offshore scenario. Overall, the Onshore scenarios average 23% availability at the peak hour and the Offshore scenarios average 54%. This is typical of their performance, even though the average annual capacity factors are not that different: 34% for Onshore and 40% for Offshore.

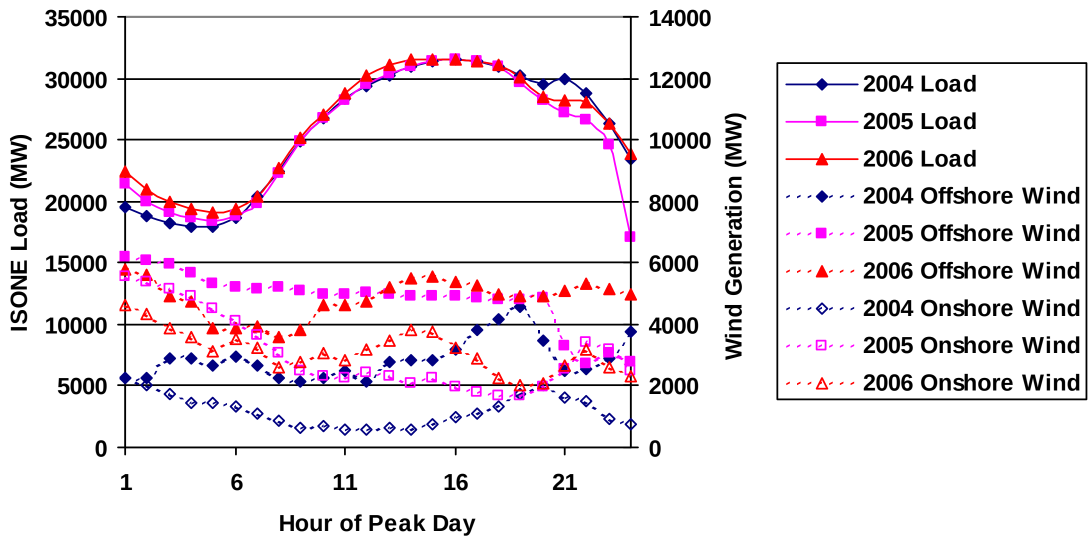

Figure 6–9 Load and wind on peak day

Table 6–1 Wind generation at the peak hour

	2004 Offshore Wind	2005 Offshore Wind	2006 Offshore Wind	2004 Onshore Wind	2005 Onshore Wind	2006 Onshore Wind
capacity	8360	8360	8360	9770	9770	9770
daily max	4578	6182	5810	2272	5533	4645
%	55%	74%	69%	23%	57%	48%
gen @ peak	3157	4896	5468	988	1940	3810
%	38%	59%	65%	10%	20%	39%

Figure 6–10 shows the average daily profile for the three years for these two scenarios. Even though the Onshore scenarios have 1410 MW more installed capacity the Offshore scenarios average more generation during the late afternoon/early evening period when the peak loads occur.

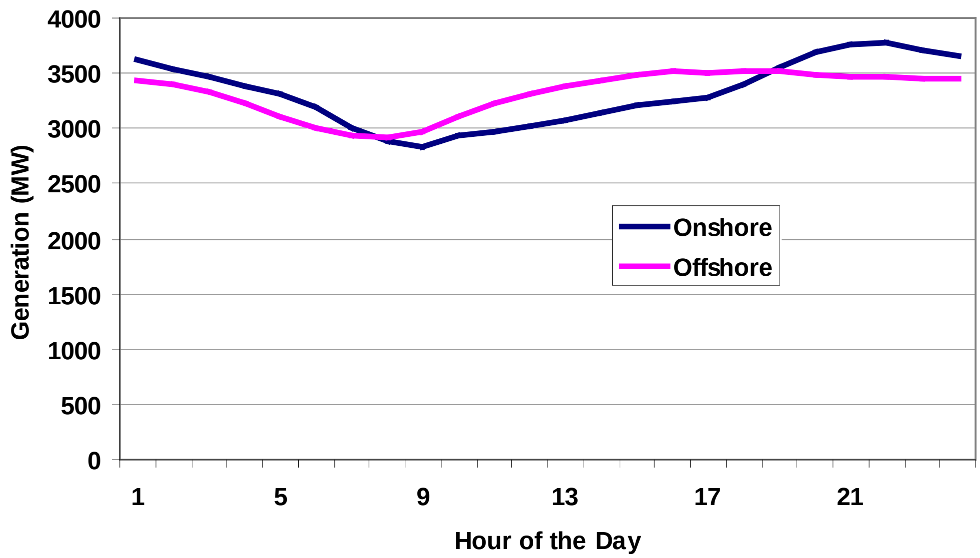

Figure 6–10 Average daily profiles, 20% energy scenarios.

Figure 6–11 shows the annual wind generation duration curves for the 20% scenarios. The energy under each curve is roughly the same but the Onshore cases tend to drop more rapidly from their peak values than the Offshore cases do.

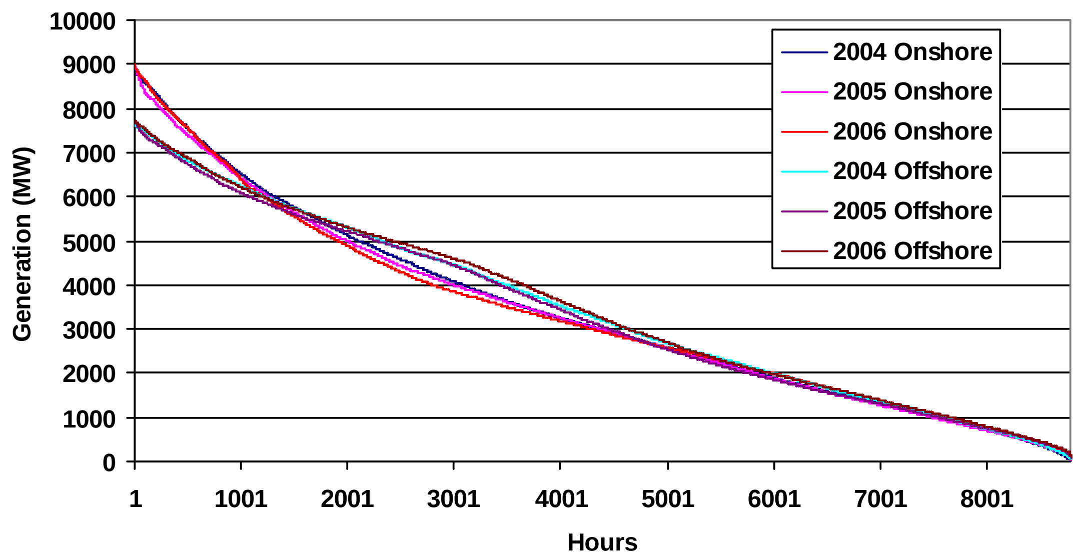

Figure 6–11 Generation duration curves for 20% penetration

Figure 6–12 shows the monthly capacity factors for the cases. The Offshore cases have significantly more energy in the peak month of July, particularly in 2006.

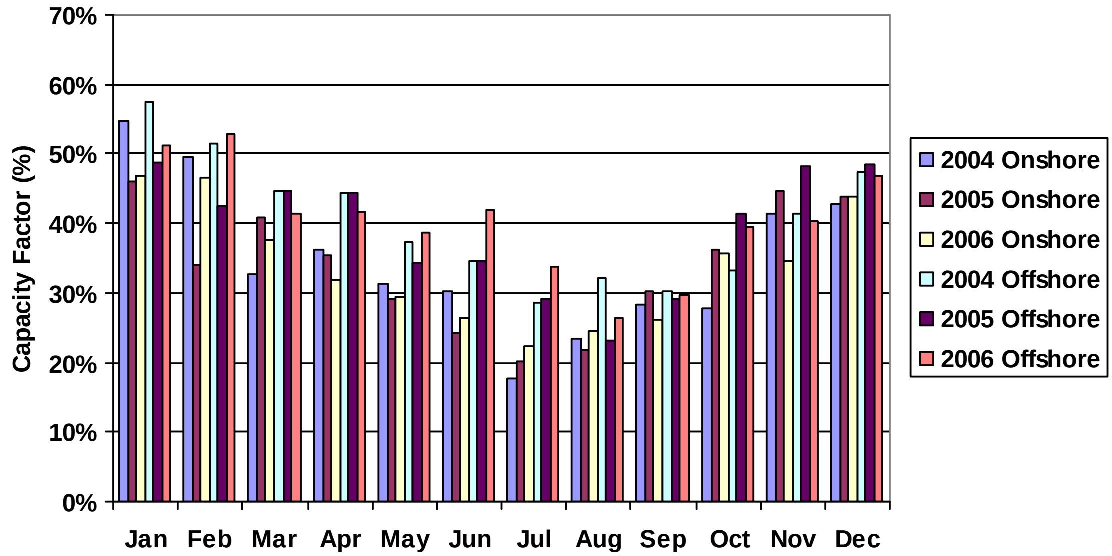

Figure 6–12 Monthly wind capacity factors for 20% scenarios

The load shapes are also a critical factor in the capacity value calculations. Figure 6–13 shows the profiles of the daily peak loads for the three load shape years.

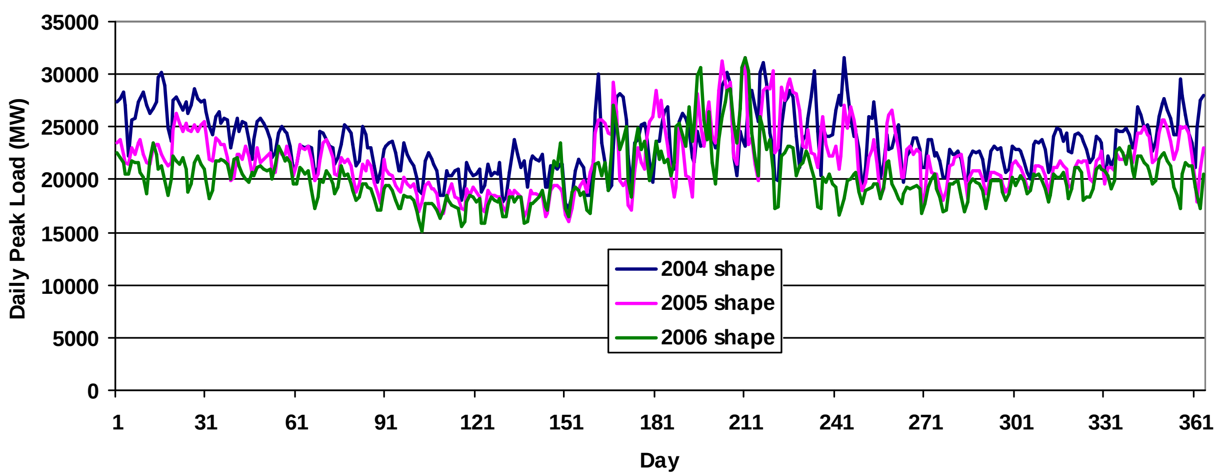

Figure 6–13 Chronological daily peak loads

Figure 6–14 sorts these daily peaks into duration curves. It can be readily seen that the 2006 daily peaks drop off much more rapidly than the other two years. This means that the wind generation on the top couple of days will have a relatively larger impact on the annual LOLE than in the other years.

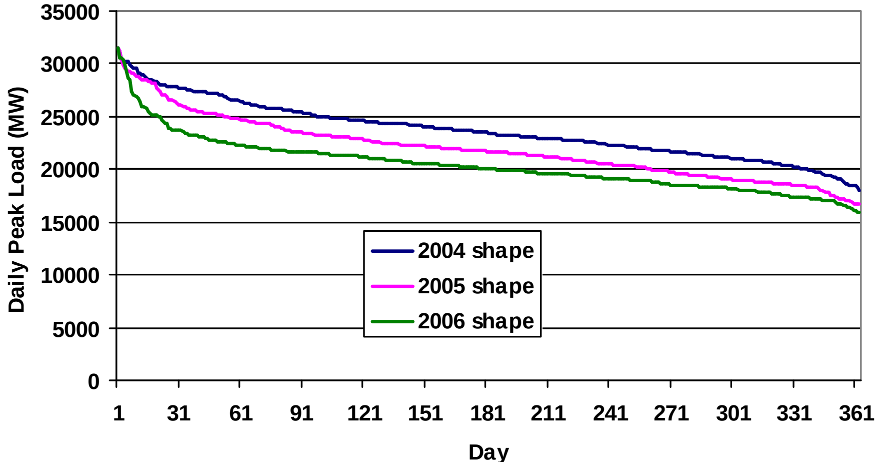

Figure 6–14 Daily peak load duration curve

The risk of system outage is exponentially related to the available reserves. Therefore, for a given level of installed capacity the risk, or LOLE, will vary exponentially with the daily peak load. Because the wind plants do not present a constant available capacity, like a typical thermal plant, the risk will vary exponentially with the amount of wind generation in the peak load hours. Figure 6–15 shows the highest six daily peak loads for the three shape years and the corresponding wind generation for the 20% onshore scenarios. When the loads are above 30,000 MW the wind generation in the 2006 case averages roughly 500 MW more generation than in the other two annual profiles. It is for these reasons that the aggregate wind capacity values calculated with the 2006 profiles were significantly higher than the other years.

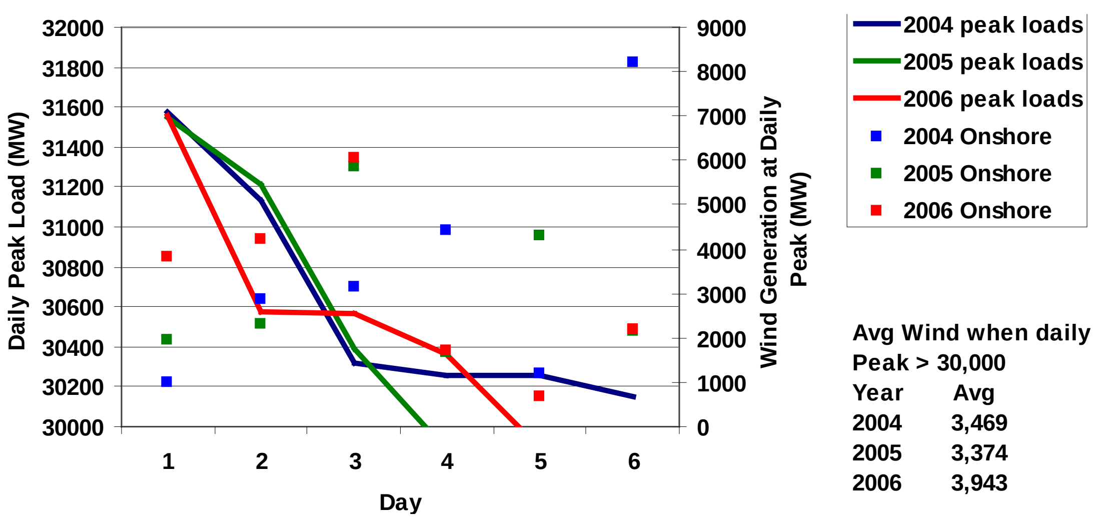

Figure 6–15 Load shapes and wind generation

Care must be taken, however, when looking at average values. Figure 6–16 expands the scope from the previous figure to show the load profile for the highest 50 daily peaks from the 2006 shape along with the corresponding hourly wind generation (as a percent of nameplate capacity) for the 20% onshore scenario (green triangles). Also shown is the rolling average capacity factor (pink line). If averages were all that mattered then it might be expected that the capacity value would be at least 30%. However, the capacity value was only 22% for this scenario. The reason is all of the points falling below the 30% line. It is these lower wind outputs that negatively affect the system risk and lower the overall capacity value. As a simple example, assume that when wind is generating at least at 30% of its rated value that no outages occur. If the wind goes up to 40% there is still no outage and therefore the risk has not improved. But if in the next hour the wind drops to 20% of its rating then there is an outage even though the average for the two hours is equal to 30%. Average capacity factors over a range of high load hours can provide a relative measure of the capacity value of the wind but a full reliability analysis is necessary to see the full impact of the non-windy days.

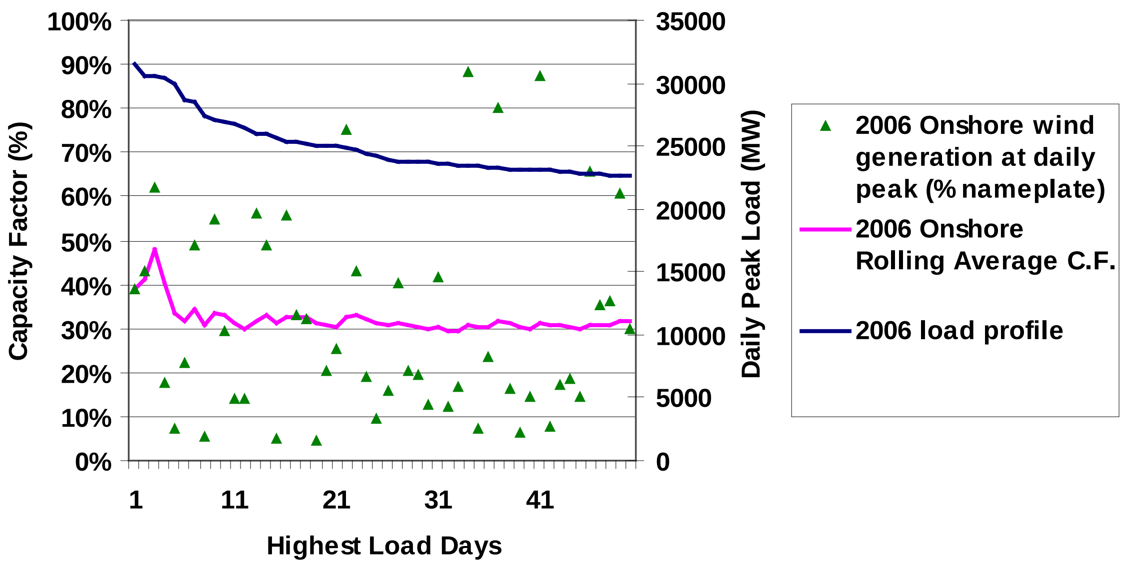

Figure 6–16 Highest Load Days, 20% Onshore Scenario, 2006 load shapes

6.5 Approximate Methodologies

The current ISO New England methodology for estimating the capacity value of wind generation uses the average capacity factor of the wind plants from 2 p.m. to 6 p.m. for the months of June through September. The results are then averaged over the past five years. That calculation was applied to the individual wind profiles for the available three years of data. Figure 6–17 compares the results for the ISO-NE's capacity factor methodology to the full ELCC technique shown previously. The ISO-NE approximate technique appears to slightly underestimate the capacity value at low penetrations and over estimate the value at the 20% level; however, it gives an overall reasonable approximation across the scenarios studied. Additionally, only three years of data were available for the ELCC calculation and the results of this method can vary somewhat from year to year. Earlier in this chapter there was discussion as to why capacity value tends to drop off with increasing penetration due to saturation and progressively poorer sites. Since the approximate methodology is only a function of the capacity factor in a specified time window then saturation does not apply. Only the impact of using the most attractive sites first, followed by sites with decreasing capacity factors is seen in the blue bars in the following charts. The approximate capacity values (labeled On-Peak CF) in Figure 6–17 only drop from 30% to 25% while the values determined from the full ELCC methodology dropped from 32% to 19%.

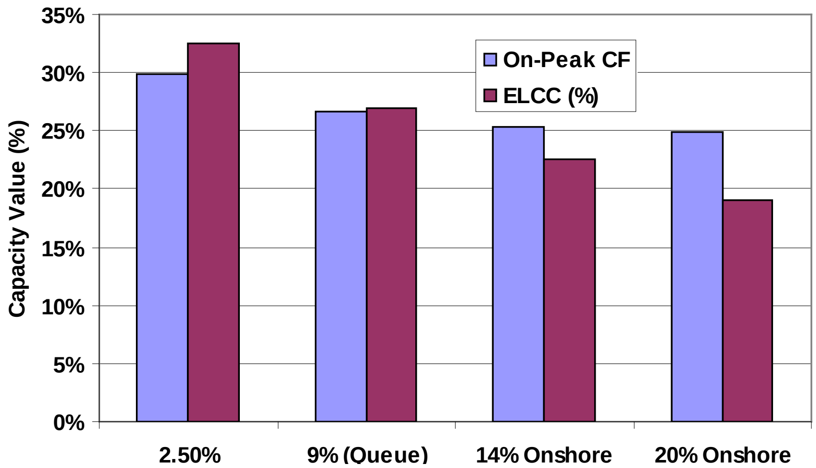

Figure 6–17 Comparison of capacity value methodologies, 2004 shapes.

Figure 6–18 and Figure 6–19 show similar results for the 2005 and 2006 load and wind shapes. Figure 6–20 shows the three year average of the two methodologies.

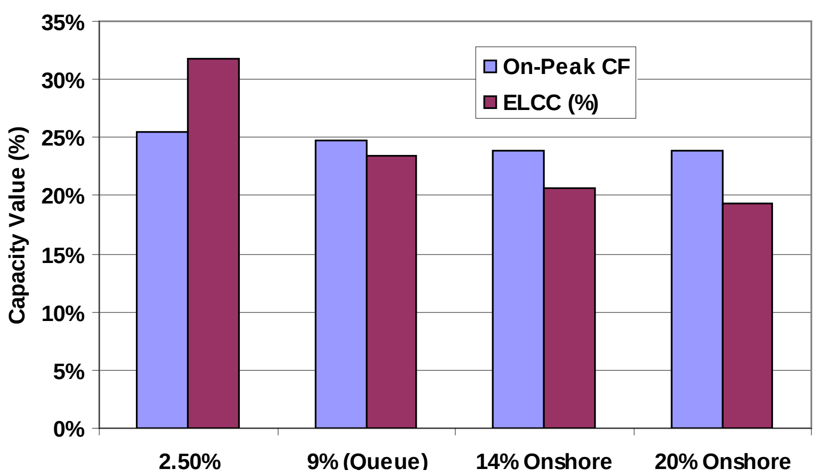

Figure 6–18 Comparison of capacity value methodologies, 2005 shapes.

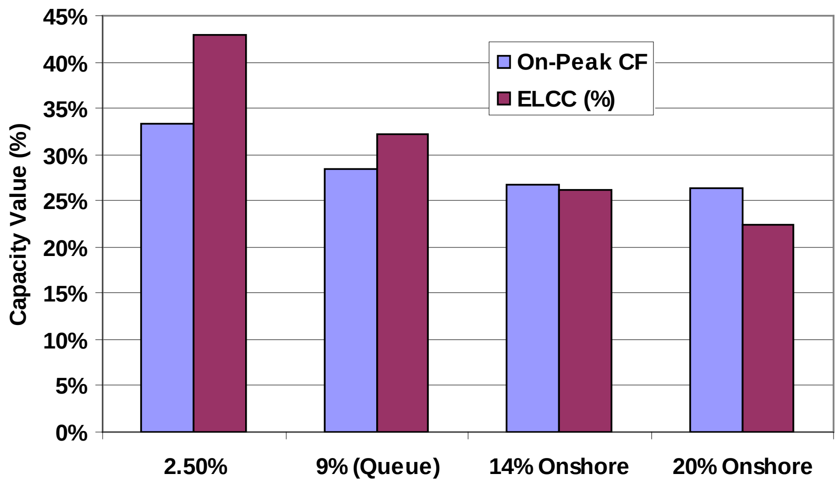

Figure 6–19 Comparison of capacity value methodologies, 2006 shapes.

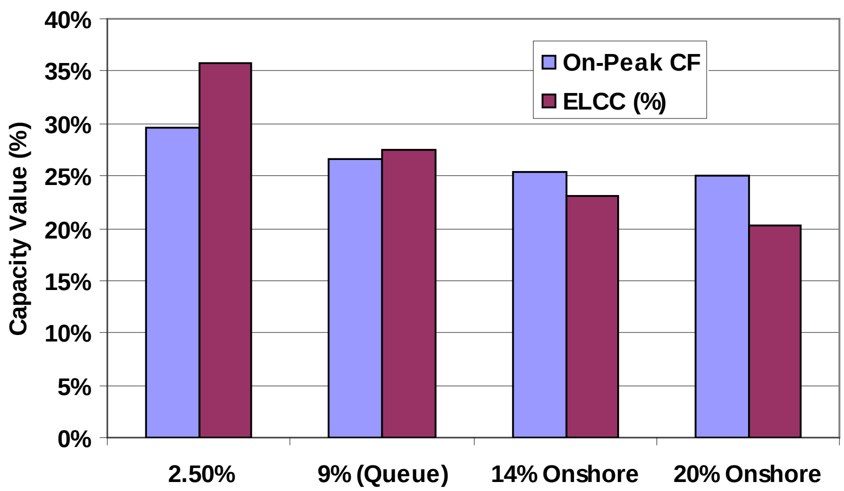

Figure 6–20 Comparison of capacity value methodologies, three year average.

All three individual years and the three-year average curve show similar results. Both methods show a decreasing capacity value as the wind penetration increases. Looking at the average results over three years, at the 2.5% energy penetration the approximate calculation underestimates the capacity value by about five percentage points, roughly 30% versus 35%. At the 20% penetration the effect is reversed. Now the approximate method appears to overestimate the capacity value by five percentage points, 25% versus 20%. The crossover appears to occur at roughly the 10% penetration level. Figure 6–21 shows that the differences in results are similar at the 20% level for the Onshore and Offshore Scenarios.

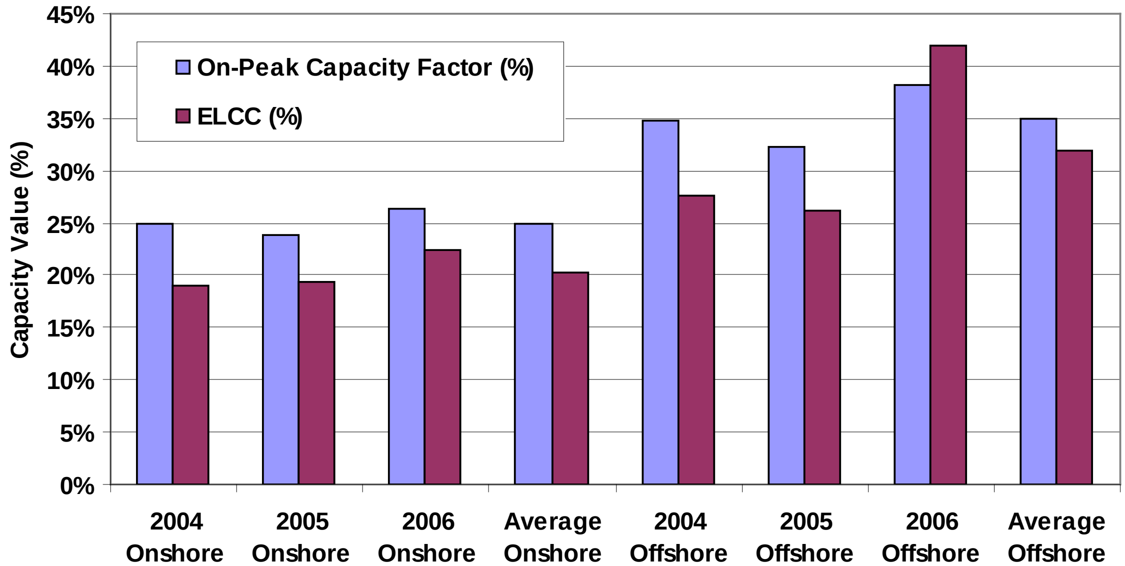

Figure 6–21 Comparison of capacity value methodologies, 20% Onshore and Offshore Scenarios.

Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE monitor a comparison between its current approximate method and the LOLE/ELCC as operational experience is gained. As wind penetration increases the Installed Capacity Requirement (ICR) may not accurately account for the intermittent nature of wind resources. GE recommends that the ISO evaluate potential improvements to the calculation of capacity values for wind resources. An example of the methodology could be:

$$CV\ CORRECTION\ FACTOR = CV_{TOTAL,\ LOLE} / CV_{TOTAL,\ APPROX\ METHOD}$$

$$CV_{PLANT} = CV_{PLANT,\ APPROX\ METHOD} \times CV\ CORRECTION\ FACTOR$$

where,

$CV_{TOTAL,\ LOLE}$ = the aggregate capacity value of all wind generation in ISO-NE, calculated using LOLE methods for all hours

$CV_{TOTAL,\ APPROX\ METHOD}$ = the aggregate capacity value of all wind generation in ISO-NE calculated using the approximate method for peak load hours

$CV_{PLANT,\ APPROX\ METHOD}$ = capacity value for a specific wind plant, calculated using the approximate method for peak load hours

CV_{PLANT} = capacity value for a specific plant, adjusted to be consistent with overall system LOLE calculations

Figure 6–22 shows the capacity value for each of the individual sites in the 20% Onshore Scenario, as determined using the approximate methodology. The two sites in the 40% to 50% band are the two actual offshore sites. The rest of the sites are all onshore and generally fall in the 20% to 30% range.

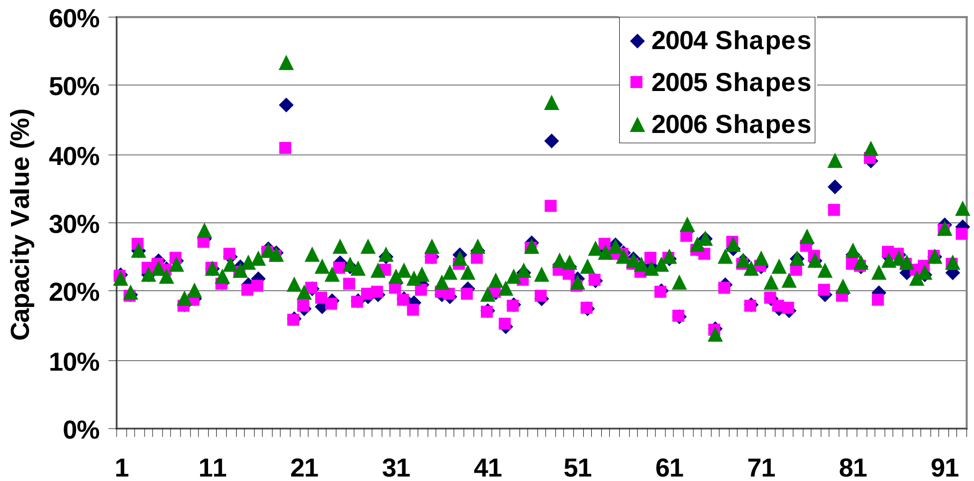

Figure 6–22 On-peak capacity factors by site for the 20% Onshore Scenario.

Figure 6–23 compares the annual capacity factor to the on-peak capacity factor for all of the sites in the 20% Onshore Scenario. In general, the capacity value (as approximated by the on-peak capacity factor) is less than the annual capacity factor, as indicated by the heavy black line.

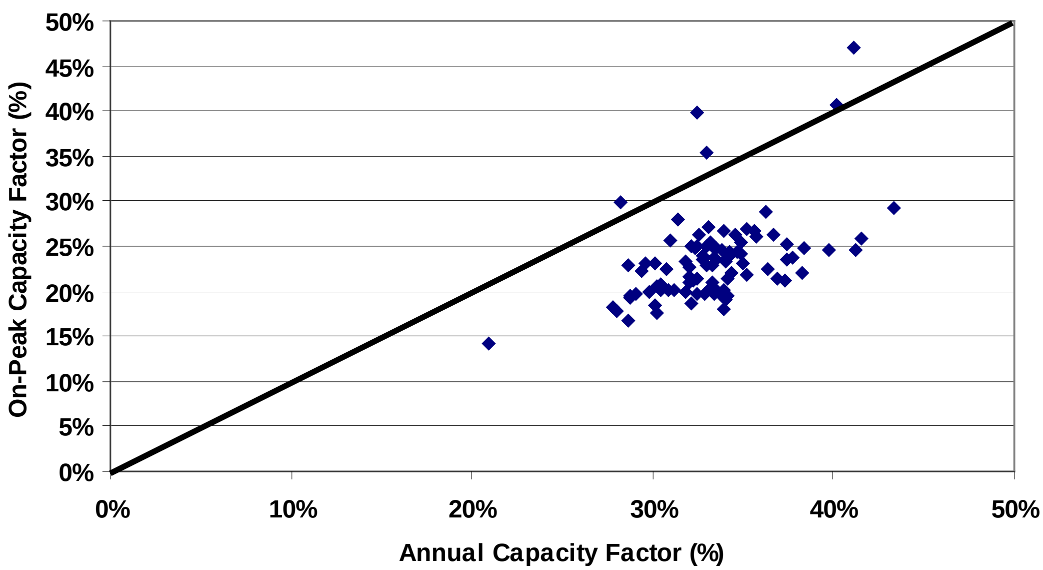

Figure 6–23 Annual capacity factor versus on-peak capacity factor, 3 year average.

6.6 Hourly Reliability Measures

Because wind and load vary hourly throughout the year the entire reliability analysis was repeated using the hours/year measure of LOLE instead of the days/year values. The results for the 20% scenario are shown in Figure 6–24. Although the index is now looking at all of the hours when outages may occur and not just the number of days, the capacity values do not change significantly.

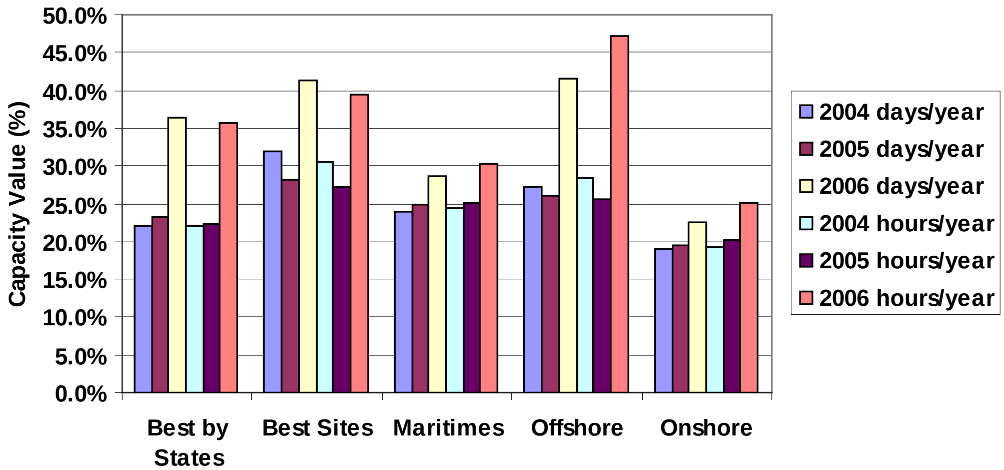

Figure 6–24 Capacity Value based on days/year versus hours/year, 20% scenario

6.7 Capacity Value Observations

This analysis used a Loss of Load Expectation (LOLE) model to calculate the Effective Load Carrying Capability (ELCC) also referred to as the capacity value, for a range of wind penetrations and scenario layouts for three different sets of annual wind and load profiles. A summary of the significant results are shown in Table 6–2. Along with the effective capacity of each scenario Table 6–2 also includes in brackets the percent of the installed capacity that is offshore. Wind capacity values can vary significantly with wind profiles, load profiles, and siting of the wind generation. On average, the 20% Onshore scenario had a capacity value of roughly 20% while the corresponding Offshore scenario was slightly better than 30%. It is important to examine multiple years of both wind and load profiles as the capacity value can be affected by the wind performance in just a few hours. The Onshore values are roughly consistent with results found in the Eastern Wind Integration and Transmission Study. The offshore sites were shown to significantly improve the capacity value.

Table 6–2 Capacity value (%) by scenario.

Scenario	3-Year Average Capacity Value (%) [% Offshore]	14% Energy 3-Year Average Capacity Value (%) [% Offshore]	20% Energy 3-Year Average Capacity Value (%) [% Offshore]
2.5 % Energy	36% [40%]		
9% Energy (Queue)	28% [20%]		
Onshore		23% [12%]	20% [8%]
Maritimes		26% [13%]	26% [9%]
Best by States		28% [15%]	26% [29%]
Best Sites		35% [47%]	34% [51%]
Offshore		34% [45%]	32% [58%]

Wind generation is added for its energy value, not for capacity reasons. Having said that it is still fair to ask “Which scenario provides the cheapest capacity value?” If capital costs for installed wind nameplate capacity for on-shore plants are assumed to be $2000/KW and off-shore plants are $3000/KW then the investment cost for the installed wind plants of each scenario can be estimated. This total investment cost can then be divided by the effective capacity to produce an average $/KW of effective capacity for each of the scenarios. Figure 6–25 presents these results in order from lowest to highest cost.

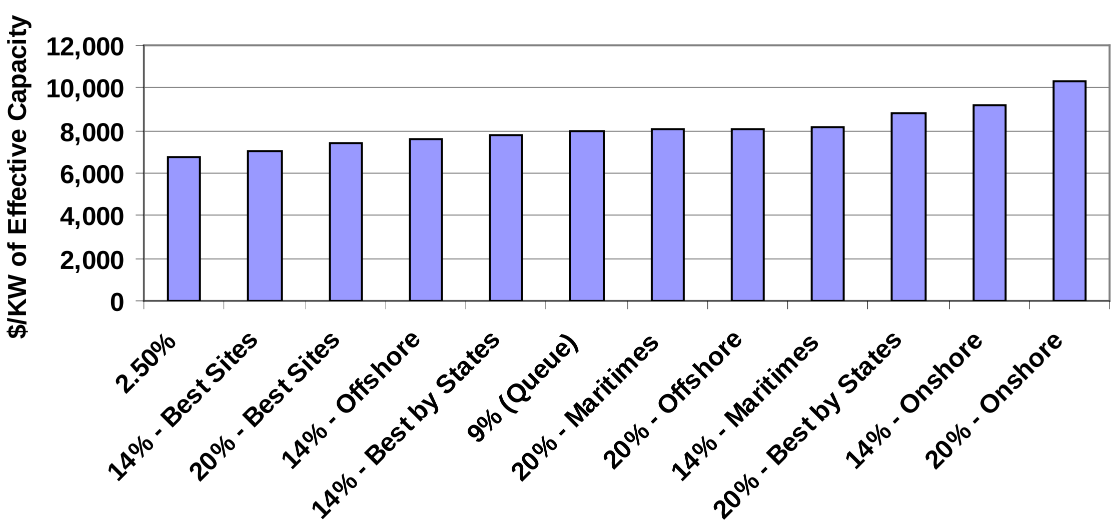

Figure 6–25 Net capital cost in $/KW of effective capacity.

The highest cost is more than 50% above the minimum value. The 14% and 20% “Best Site” scenarios are towards the low cost end of the curve while the corresponding “Onshore” scenarios are at the highest end. Again, it should be cautioned that these reflect the capacity value only and do not include the costs for the necessary transmission or the economic and environmental value of the fuel displaced.

7 Key Findings and Recommendations

The study results show that New England could potentially integrate wind resources to meet up to 24% of the region's total annual electric energy needs in 2020 if the system includes transmission upgrades comparable to the configurations identified in the Governors' Study. It is important to note that this study assumes (1) the continued availability of existing supply-side and demand-side resources as cleared through the second FCA (in other words, no significant retirements relative to the capacity cleared through the second FCA), (2) the retention of the additional resources cleared in the second Forward Capacity Auction, and (3) increases in regulation and operating reserves as recommended in this study.

Figure 7–1 shows the annual energy from the ISO-NE generation fleet with increasing levels of wind generation for the NEWIS study of the horizon year 2020. The pie charts are for the best sites onshore layout, but since energy targets are the same for all layout alternatives within each scenario, the results presented in the pie charts are very similar across the range of layout alternatives within each scenario.

The existing ISO-NE generation fleet is dominated by natural-gas-fired resources, which are potentially very flexible in terms of ramping and maneuvering. As shown in the upper left pie chart of Figure 7–1, natural gas resources provide about 50% of total annual electric energy in New England assuming no wind generation on the system. Wind generation would primarily displace natural-gas-fired generation since gas-fired generation is most often on the margin in the ISO-NE market. The pie charts show that as the penetration of wind generation increases, energy from natural gas resources is reduced while energy from other resources remains relatively constant. At a 24% wind energy penetration, natural gas resources would still be called upon to provide more than 25% of the total annual energy (lower right pie chart). In effect, a 24% wind energy scenario would likely result in wind and natural-gas-fired generation providing approximately the same amount of energy to the system, which would represent a major shift in the fuel mix for the region. It is unclear, given the large decrease in energy market revenues for natural-gas-fired resources, whether these units would be viable and therefore continue to be available to supply the system needs under this scenario.

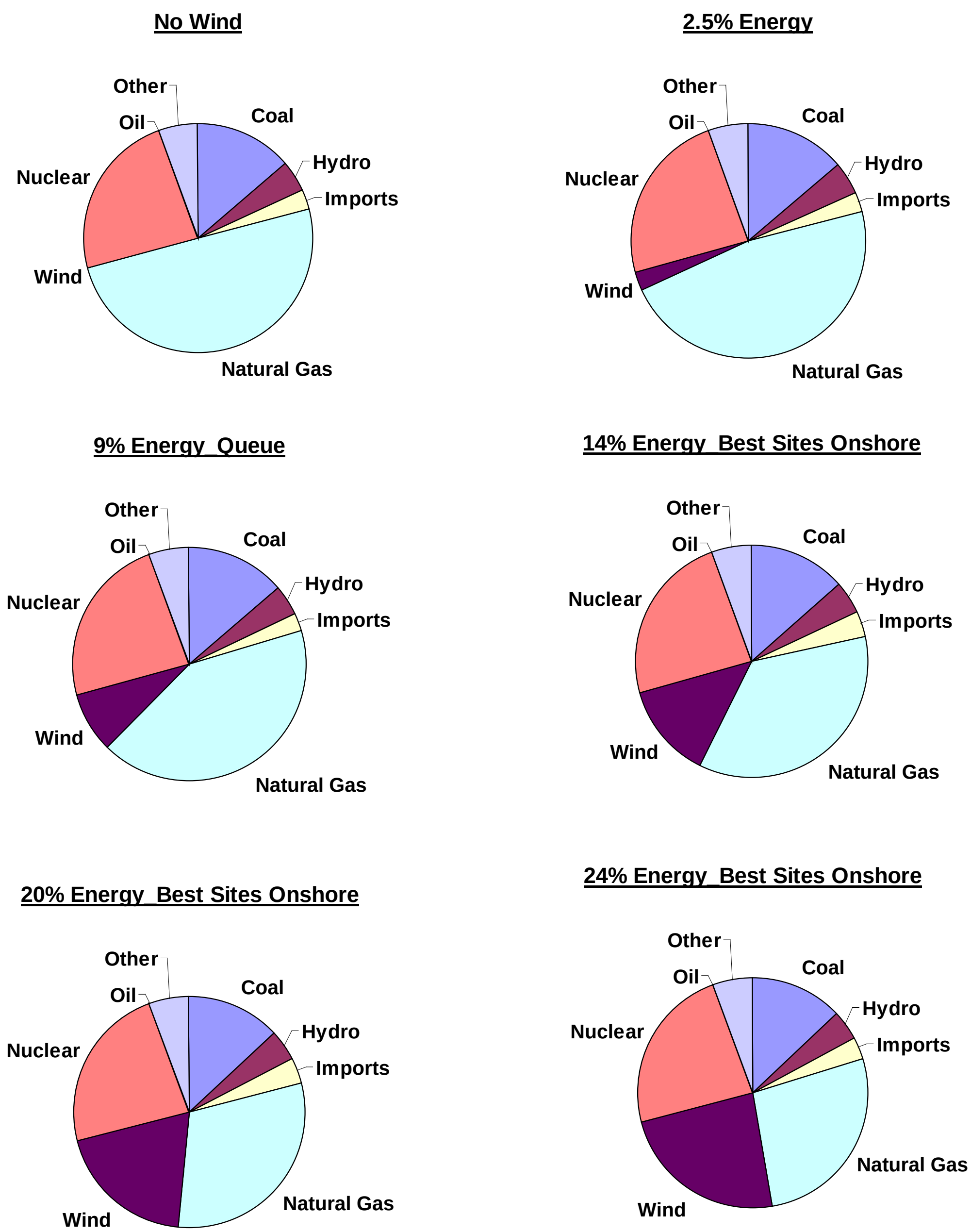

Figure 7–1 Annual Energy from ISO-NE Generation Fleet with Increasing Wind Energy Penetration.

The remainder of this chapter is organized as follows. Sections 7.1 through 7.4 summarize key analytical results related to statistical characterization of the scenarios, regulation and operating reserves, impacts on hourly operations, and capacity value of wind generation. Section 7.5 presents a high-level comparison of the study scenarios. Section 7.6 presents recommended changes to ISO-NE operating rules and practices related to the following issues:

- Capacity Value
- Regulation

- Reserves
- Wind Forecasting
- Maintaining System Flexibility
- Wind Generation and Dispatch
- Saving and Analyzing Operating Data

Section 7.7 summarizes other significant observations from the study results, including:

- Flexible Generation
- Energy Storage
- Dynamic Scheduling
- Load and Wind Forecasting with Distributed Wind Generation

Section 7.8 relates recommendations and observations in this report back to the technical requirements for interconnection of wind plants in the previously published Task 2 report. Section 7.9 includes recommendations for future work.

7.1 Statistical Analysis

The observations and conclusions here are made on the basis of three years of synthesized meteorological and wind production data corresponding to calendar years 2004, 2005, and 2006. Historical load data for those same calendar years were scaled up to account for anticipated load growth through year 2020.

The wind generation scenarios defined for this study show that the winter season in New England is where the highest wind energy production can be expected. As is the case in many other parts of the United States, the higher load season of summer is the “off-season” for wind generation.

While New England may benefit from an increase in electric energy provided by wind generation primarily during the winter period, the region will still need to have adequate capacity to serve summer peak demand. Given current operating practices and market structures, the potential displacement of electric energy provided by existing resources raises some concern for maintaining adequate capacity (essential for resource adequacy) and a flexible generation fleet (essential to balance the variability of wind generation).

The capacity factors for all scenarios follow the same general trend. Seasonal capacity factors above 45% in winter are observed for several of the scenarios. In summer, capacity factors drop to less than 30%, except for those scenarios that contain a significant share of offshore wind resources.

Based on averages over the entire dataset, seasonal daily patterns in both winter and summer exhibit some diurnal (daily) behavior. Winter wind production shows two daily maxima, one in the early morning after sunrise, and the other in late afternoon to early evening. Summer patterns contain a drop during the nighttime hours prior to sunrise, then an increase in production through the morning hours. It is enticing to think that such patterns could assist operationally with morning load pickup and peak energy demand, but the patterns described here are averages of many days. The likelihood of any specific day ascribing to the long-term average pattern is small.

The net load average patterns by season reveal only subtle changes from the average load shape. No significant operational issues can be detected from these average patterns. At the extremes, the minimum hourly net load over the data set is influenced substantially. In one of the 20% energy scenario layouts, the minimum net load drops from just about 10 GW for load alone to just over 3 GW. Impacts of these low net load periods were assessed with the production simulation analysis.

The day-ahead wind power forecasts developed for each scenario show an overall forecast accuracy of 15% to 20% Mean Absolute Error (MAE). This is consistent with what is considered the state of the commercial art. These forecast errors represent the major source of uncertainty attributable to wind generation. The impacts of forecast errors on hourly operations were evaluated in the production simulation analysis.

Shorter-term wind power forecasts are also valuable for system operations. This study addressed the use of persistence forecasts over the hour-ahead and ten-minute-ahead time periods. A persistence forecast assumes that future generation output will be the same as current conditions. For slowly changing conditions, short-term persistence forecasts are currently about as accurate statistically as those that are skill-based, but this relationship breaks down as hour-to-hour wind variability increases. Operationally significant changes in wind generation over short periods of time, from minutes to hours (known as ramping events), highlight this issue. As a first estimate, operationally significant ramps are often considered to be a 20 percent change in power production within 60 minutes or less. However, the actual percent change that is operationally significant varies depending on the characteristics of the power grid and its resources. As the rate and magnitude of a ramp increases, persistence forecasts tend to become less and less accurate for the prediction of short-term wind generation.

While the persistence assumption works for a study like this one, in reality ISO-NE will need better ramp-forecasting tools as wind penetration increases. Such tools would give operators the means to prepare for volatile periods by allocating additional reserves or making other system adjustments. There has been recent progress in this area and better ramp forecasting tools are now being developed. For example, AWS Truepower recently deployed a system for the Electric Reliability Council of Texas (ERCOT) known as the ERCOT Large Ramp Alert System (ELRAS), which provides probabilistic and deterministic ramp event forecast information through a customized web-based interface. ELRAS uses a weather prediction model running in a rapid update cycle, ramp regime-based advanced statistical techniques, and meteorological feature tracking software to predict a range of possible wind ramp scenarios over the next nine hours. It is highly recommended that ISO-NE pursue the development of a similar system tailored to forecast the types of ramps that may impact New England.

7.2 Regulation and Operating Reserves

Statistical analysis of load and wind generation profiles as well as ISO-NE operating records of Area Control Error (ACE) performance were used to quantify the impact of increasing penetration of wind generation on regulation and operating reserve requirements.

All differences between the scenarios stem from the different variability characteristics extracted from three years of mesoscale wind production data in the NEWRAM. The methodology and ISO-NE load are the same for each scenario, so wind variability is the only source of differences between scenarios.

7.2.1.1 Regulation

Significant penetration of wind generation will increase the regulation capacity requirement and will increase the frequency of utilization of these resources. The study identified a need for an increase in the regulation requirement even in the lowest wind penetration scenario (2.5% wind energy), and the requirement would have noticeable increases for higher penetration levels. For example, the average regulation requirement for the load only (i.e., no wind) case was 82 MW. This requirement increases to 161 MW in the 9% wind energy scenario—and to as high as 313 MW in the 20% scenario.

The primary driver for increased regulation requirements due to wind power is the error in short-term wind power forecasting. The economic dispatch process is not equipped to adjust fast enough for the errors inherent in short-term wind forecasting and this error must be balanced by regulating resources. (This error must be accounted for in addition to the load forecasting error.)

Figure 7–2 shows regulation-duration curves for increasing levels of wind penetration. It shows the number of hours per year where regulation needs to be equal to or greater than a given value. For example, the dark blue curve (the left-most curve) shows that between 30 MW and 190 MW of regulation are required for load alone. The 2.5% Partial Queue scenario (the light blue line to the right of the load-only curve) increases the regulation requirement to a range of approximately 40 MW to 210 MW; the overall shape tracks that of the load-only regulation requirement curve. In the higher wind penetration scenarios, this minimum amount of required regulation capacity increases and the average amount of regulation required increases such that the shapes of the curves no longer track that of the load-only curve—this is indicative that the increased regulation capacity will likely be required to be utilized more frequently. The purple curve (the middle curve) shows that a range of approximately 50 MW to 270 MW of regulation is required with 9% wind energy penetration. The yellow and red curves (to the right of the 9% wind penetration curve just discussed) show that the required regulation increases to ranges of approximately 75 MW to 345 MW and approximately 80 MW to 430 MW, respectively. These estimates are based on rigorous statistical analysis of wind and load variability.

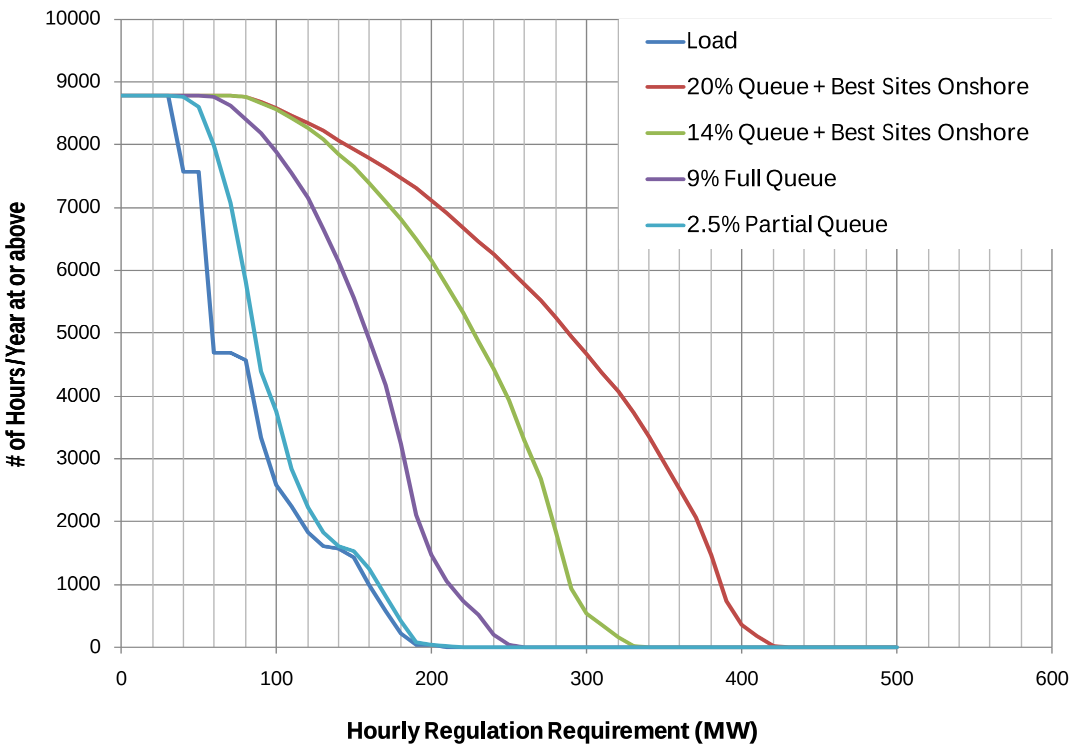

Figure 7–2 Regulation Requirements with Increasing Wind Energy Penetration

At 20% wind energy penetration, the average regulation requirement is estimated to increase from approximately 80 MW without wind, to a high of approximately 315 MW with 20% wind depending on the differences within the scenario. At lower penetration levels, the incremental regulation requirement is smaller. The hourly analysis indicates average regulation requirements would increase to a high of approximately 230 MW with 14% wind energy penetration. At 9% wind energy penetration, the average regulation would increase to approximately 160 MW. At the lowest wind penetration studied (2.5%) average required regulation capability would increase to approximately 100 MW. Alternate calculation methods that include historical records of ACE performance, synthesized 1-minute wind power output, and ISO-NE operating experience suggest that the regulation requirement may increase less than these amounts.

There are some small differences in regulation impacts discernable amongst layouts at the same energy penetration levels. This can be traced directly to the statistics of variability used in these calculations. Based on the ISO-NE wind generation mesoscale data, some scenario layouts of wind generation exhibit higher variability from one ten-minute interval to the next. A number of factors could contribute to this result, including the relative size of the individual plants in the scenario layout (and the impact on spatial and geographic diversity), the local characteristics of the wind resource as replicated in the numerical weather simulations from which the data is generated, and even the number of individual turbines comprising the scenario, as more turbines would imply more spatial diversity. At the same time, however, the differences may be within the margin of uncertainty inherent in the analytical methodologies for calculating regulation impacts. Given these uncertainties, it is difficult to draw concrete conclusions regarding the relative merits of one scenario layout over the others.

ISO-NE routinely analyzes regulation requirements and makes adjustments. As wind generation is developed in the market footprint, similar analyses will take place. Control performance objectives and the empirically observed operating data that includes wind generation should be taken into account in the regulation adjustment process.

ISO-NE’s current practice for monitoring control performance and evaluating reserve policy should be expanded to explicitly include consideration of wind generation once it reaches a threshold where it is visible in operational metrics. A few methods by which this might be done are discussed in Chapter 4, and ISO-NE will likely find other and better ways as their experience with wind generation grows. ISO-NE should collect and archive high-resolution data from each wind generation facility to support these evaluations.

Analysis of these results indicates, assuming no attrition of resources capable of providing regulation capacity, that there may be adequate supply to match the increased regulation requirements under the wind integration scenarios considered. ISO-NE’s business process is robust and is designed to assure regulation adequacy as the required amount of regulation develops over time and the needs of the system change.

7.2.1.2 Operating Reserves

Additional spinning and non-spinning reserves will be required as wind penetration grows. The analysis indicates that Ten Minute Spinning Reserve (TMSR) would need to be supplemented as penetration grows to maintain current levels of contingency response. Increasing TMSR by the average amount of additional regulation required for wind generation is a potential option to ensure that the spinning reserve available for contingencies would be consistent with current practice.

Using this approach, TMSR would likely need to increase by 310 MW for the 20% energy penetration scenarios, about 125 MW for 14% penetration, and about 80 MW for 9% penetration.

In addition to the penetration level, the amount is also dependent on the following factors:

- The amount of upward movement that can be extracted from the sub-hourly energy market – the analysis indicates that additional Ten Minute Non-Spinning Reserve (TMNSR), or a separate market product for wind generation, would be needed at 20% penetration
- The current production level of wind generation relative to the aggregate nameplate capacity, and
- The number of times per period (e.g., year) that TMSR and Thirty Minute Operating Reserve (TMOR) can be deployed – for the examples here, it was assumed that these would be deployed 10 times per period.

The amount of additional non-spinning reserve that would be needed under conditions of limited market flexibility and volatile wind generation conditions is about 300 MW for the 20% Best Sites Onshore case, and 150 MW for the 9% Energy Queue case. This incremental amount would maintain the TMNSR designated for contingency events per existing practice, where it is occasionally deployed for load changes. “Volatile wind generation conditions” would ultimately be based on ongoing monitoring and characterization of the operating wind generation. Over time, curves like those in Figure 4-5 would be developed from monitoring data and provide operators with an increasingly confident estimate of the expected amount of wind generation that could be lost over a defined interval.

The additional TMNSR would be used to cover potentially unforecasted extreme changes (reductions) in wind generation. As such, its purpose and frequency of deployment are different from the current TMNSR. This may require consideration of a separate market product that recognizes these differences. ISO-NE should also investigate whether additional TMOR could be substituted to some extent for the TMSR and/or TMNSR requirements related to wind variability.

Due to the increases in TMSR and TMNSR, overall Total Operating Reserve (TOR) increases in all wind energy scenarios. For the 2.5% wind energy scenario, the average required TOR increases from 2,250 MW to 2,270 MW as compared to the no wind energy scenario baseline. The average required TOR increases to approximately 2,600 MW with 14% wind penetration and about 2,750 MW with 20% penetration.

The need for additional reserves varies as a function of wind generation. Therefore, it would be advantageous to have a process for scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind generation. It may be inefficient to schedule additional reserves using the existing "schedule" approach, by hour of day and season of year, since that may result in carrying excessive reserves for most hours of the year. The process for developing and implementing a day-ahead reserves scheduling process may involve considerable effort and investigation of this process was outside the scope of the NEWIS.

7.3 Analysis of Hourly Operations

Production simulation analysis was used at an hourly time-step to investigate operations of the ISO-NE system for all the study scenarios under the previously stated assumptions of transmission expansion, no attrition of dispatchable resources, addition of resources that have cleared in the second Forward Capacity Auction, and the use of all of the technical capability of the system (i.e., exploiting all system flexibility). The results of this analysis indicate that integrating wind generation up to the 24% wind energy scenario is operationally feasible and may reduce average system-wide variable operating costs (i.e., fuel and variable O&M costs) in ISO-NE by $50 to $54 per megawatt-hour of wind energy[74]; however, these results are based on numerous assumptions and hypothetical scenarios developed for modeling purposes only. The reduction in system-wide variable operating cost is essentially the marginal cost of energy, which should not be equated to a reduction in $/MWh for market clearing price (i.e. Locational Marginal Prices--LMPs). Low-priced wind resources could displace marginal resources, but that differential is not the same as reductions in LMPs.

[74] In essence, this is the cost to replace one MWh of energy from wind generation with one MWh of energy from the next available resource from the assumed fleet of conventional resources.

As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and therefore should not be considered the primary basis for evaluating the different scenarios.

Wind energy penetrations of 2.5%, 9%, 14%, 20%, and 24% were evaluated. As wind penetrations were increased up to 24%, there were increasing amounts of ramp down insufficiencies with up to approximately 540 hours where there may potentially be insufficient regulation down capability. There were no violations that occurred for the regulation up. The transmission system with the 4 GW overlay was adequately designed to handle 20% wind energy without significant congestion. The transmission system with the 8 GW overlay was adequately designed to handle 24% wind energy without significant congestion.

Wind generation primarily displaces natural-gas-fired combined cycle generation for all levels of wind penetration, with some coal displacement occurring at higher wind penetrations.

The study showed relatively small increases in the use of existing pumped-storage hydro for large wind penetrations; because balancing of net load—an essential requirement for large-scale wind integration—was largely provided by the flexibility of the natural-gas-fired generation fleet. It is possible that retirements (attrition) of some generation in the fleet would increase the utilization of PSH, but that was not examined in this study.

The lack of a price signal to increase use of energy storage is the primary reason the study showed small increases in the use of pumped-storage hydro in the higher wind penetrations. For energy arbitrage applications, like pumped storage hydro, a persistent spread in peak and off-peak prices is the most critical economic driver. The differences between on-peak and off-peak prices were small because natural-gas-fired generation remained on the margin most hours of the year. Over the past six years, GE has completed wind integration studies in Texas, California, Ontario, the western region of the United States, and Hawaii. In many of these studies, as the wind power penetration increases, spot prices tend to decrease, particularly during high priced peak hours. The off-peak hours remain relatively the same. Therefore, the peak and off-peak price spread shrinks and no longer has sufficient range for economic storage operation. An example of this can be seen in Figure 7–3. The figure shows the LMP for the week of April 1, 2020, for the 20% Best Sites Onshore scenario, using year 2004 wind and load shapes. It also shows the LMP for a case with no wind generation. The price spread decreases substantially, which reduces the economic driver for energy storage due to price arbitrage.

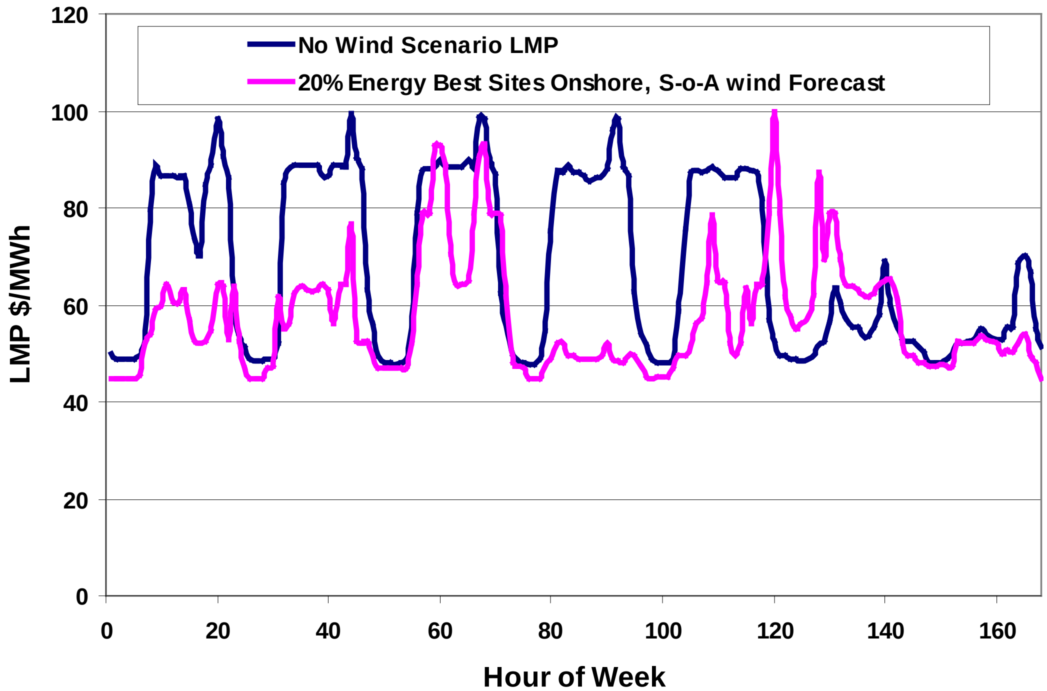

Figure 7–3 LMP for Week of April 1, Comparison of No Wind and 20% Wind Energy

With 20% wind energy penetration, the following impacts were observed on emissions and energy costs:

- NOx emissions were reduced by approximately 6,000 tons per year, a 26% reduction compared to no wind.
- SOx emissions were reduced by approximately 4,000 tons per year, a 6% reduction compared to no wind.
- CO_2 emissions were reduced by approximately 12,000,000 tons per year, a 25% reduction compared to no wind. (Wind generation will not displace other non- CO_2-producing generation, such as hydro and nuclear. Therefore, 20% energy from wind reduces the energy from CO_2-producing generation by 25 to 30%. Considering that wind generation primarily displaces natural-gas-fired generation in New England, the overall CO_2 production declines by 25% with 20% wind energy penetration).

- Average annual Locational Marginal Price (LMP) across ISO-NE[75] was reduced by
  - Best Sites Maritimes - $5/MWh
  - Best Sites Onshore - $6/MWh
  - Best Sites - $9/MWh
  - Best Sites Offshore - $9/MWh
  - Best Sites By State - $11/MWh

Variation in the LMP impact for the different layout alternatives results from the differences in the monthly wind profile as well as the daily profile. For example, the Maritimes layout alternative has slightly less energy in the summer than the other scenarios. Also, the Maritimes has less energy in the afternoon to early evening period, than the other scenarios when looking at the daily average summer profile. As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and actual changes in fuel prices, transmission system topology, and resource flexibility will have significant impacts on these results.

Revenue reductions for units not being displaced by wind energy is roughly 5%-10%, based on lower spot prices. For units that are being displaced, their revenue losses are even greater. This will likely lead to higher bids for capacity and may lead to higher bids for energy in order to maintain viability. The correct market signals must be in place in order to ensure that an adequate fleet of flexible resources is maintained.

The study scenarios utilized the transmission system overlays originally developed for the Governors' Study. With these transmission overlays, some scenarios exhibited no transmission congestion and others showed only a few hours per year with transmission congestion. This suggests that somewhat less extensive transmission enhancements might be adequate for the wind penetration levels studied, although further detailed transmission planning studies would be required to fully assess the transmission requirements of any actual wind generation projects.

[75] Based on the hourly marginal unit price. The results also do not account for other factors that may change business models of market participants.

7.4 Capacity Value of Wind Generation

Table 7–1 summarizes the average three-year capacity values for the total New England wind generation for all the scenarios analyzed in this study as calculated using the Loss of Load Expectation (LOLE) methodology where wind generation is treated as a load modifier. As mentioned in the NEWIS Task 2 report, using three years of data only gives some indication as to the variability of the effective capacity of wind generation from year to year. Along with the effective capacity of each scenario, Table 7–1 also includes in brackets the percent of the installed capacity that is offshore for that scenario.

Wind capacity values can vary significantly with wind profiles, load profiles, and siting of the wind generation. For example, the 20% Best Sites Onshore scenario has a wind generation capacity value of 20% while the corresponding 20% Best Sites Offshore scenario has a 32% capacity value. The capacity value of wind generation is dominated by the wind performance during just a few hours of the year when load demand is high. Hence, the capacity value of wind generation can vary significantly from year to year. For example, the 20% Best Sites Offshore scenario had wind capacity values of 27%, 26% and 42% for 2004, 2005 and 2006 wind and load profiles, resulting in the 32% average capacity value shown in Table 7–1.

Table 7–1 Summary of Wind Generation Capacity Values by Scenario and Energy Penetration

Scenario	3-Year Average Capacity Value (%) [% Offshore]	14% Energy 3-Year Average Capacity Value (%) [% Offshore]	20% Energy 3-Year Average Capacity Value (%) [% Offshore]
2.5 % Energy	36% [40%]		
9% Energy (Queue)	28% [20%]		
Onshore		23% [12%]	20% [8%]
Maritimes		26% [13%]	26% [9%]
Best by States		28% [15%]	26% [29%]
Best Sites		35% [47%]	34% [51%]
Offshore		34% [45%]	32% [58%]

7.5 High-Level Comparison of Scenarios

Overall, for a given penetration of wind energy, differences in the locations of wind plants had very little effect on overall system performance. For example, the system operating costs and operational performance were roughly the same for all the 20% wind energy penetration scenarios analyzed. This is primarily because all the wind layout alternatives had somewhat similar wind profiles (since all of the higher penetration scenarios included the wind generation from the Full Queue), there was no significant congestion on the assumed transmission systems, and the assumed system had considerable flexibility, which made it robust in its capability of managing the uncertainty and variability of additional wind generation across and between the studied scenarios.

The individual metrics (e.g., prices, emissions) are useful in comparing scenarios, but should not be used in isolation to identify a preferred scenario or to predict actual future results.

Offshore wind resources yielded higher capacity factors than onshore resources across all scenarios and also tended to better correlate with the system's electric load. The study indicates that offshore wind resources would have higher capital costs, but generally require less transmission expansion to access the electric grid. Some scenarios with the lowest predicted capital costs (for wind generation only) also required the most amount of transmission because the resources are remote from load centers and the existing transmission system.

Some scenarios that showed the least transmission congestion also required the greatest investment in transmission, so congestion results should not be evaluated apart from transmission expansion requirements. Some scenarios that showed the greatest reductions in LMPs and generator emissions also used wind resources with low capacity factors, which would result in higher capital costs.

7.6 Recommended Changes to ISO-NE Operating Rules and Practices

Capacity Value: Capacity value of wind generation is a function of many factors, including wind generation profiles for specific wind plants, system load profiles, and the penetration level of wind generation on the ISO-NE system. ISO-NE currently estimates the capacity value using an approximate methodology based on the plant capacity factor during peak load hours. This methodology was examined in Chapter 6 and gives an overall reasonable approximation across the scenarios studied. Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE monitor a comparison between its current approximate method and the LOLE/ELCC as operational experience is gained. As wind penetration increases, the Installed Capacity Requirement (ICR) may not accurately account for the intermittent nature of wind resources. GE recommends that the ISO evaluate potential improvements to the calculation of capacity values for wind resources. Given that the capacity value of wind is significantly less than that of typical dispatchable resources, much of the conventional capacity may be required regardless of wind penetration (Section 6.5).

Regulation: ISO-NE presently schedules regulation by time of day and season of year. This has historically worked well as regulation requirements were primarily driven by load, which has predictable diurnal and seasonal patterns. Wind generation does not have such regular patterns. At low levels of wind penetration, the existing process for scheduling regulation should be adequate, since the regulation requirement is not significantly affected by wind. However, with higher penetrations of wind generation (above 9%), it will likely become advantageous to adjust regulation requirements daily, as a function of forecasted and/or actual wind generation on the ISO-NE system. Due to the additional complexity of accommodating large-scale wind power, it is recommended that ISO-NE develop a methodology for calculating the regulation requirements for each hour of the next day, using day-ahead wind generation forecasts.

Determination of actual regulation requirements will need to grow from operating experience, similar to the present methods employed at ISO-NE (See Section 4.4.3).

TMSR: Spinning reserve is presently dictated by largest contingency (typically 50% of 1,500 MW, the largest credible contingency on the system). ISO-NE presently includes regulation within TMSR. With increased wind penetration, regulation requirements will increase to a level where this practice may need to be changed – probably before the system reaches 9% wind energy penetration. Either regulation should be allocated separately from TMSR, or TMSR should be increased to cover the increased regulation requirements. The latter alternative was assumed for this study, and TMSR values in this report reflect that (See Section 4.5.1).

TMNSR: Analysis of the production simulations for selected scenarios revealed that additional TMNSR might be needed to respond to large changes in wind generation over periods of tens of minutes to an hour or more. Given the assumption of no attrition of resources, displacement of marginal generation by wind energy may help to ensure that this capacity is available. In other words, some resources that are displaced by wind may be able to participate as fast start TMNSR—if those resources are assumed to continue to be available. A mechanism for securing this capacity as additional TMNSR during periods of volatile wind generation (as shown in the statistical analysis and the characterizations developed for the operating reserve analysis) may need to be developed. The use of TMOR instead of and/or in combination with TMNSR should be investigated (See Section 4.5.3).

Wind Forecast: Day-ahead wind forecasting should be included in the ISO-NE economic day-ahead security constrained unit commitment and reserve adequacy analysis. At the present level of wind penetration, this practice is not critical. At larger penetrations, if wind forecasts are not included in the economic day-ahead unit commitment, then conventional generation may be overcommitted, operating costs may be increased, LMPs may be depressed, the system may have much more spinning reserve margin than is necessary, and wind generation may be curtailed more often than necessary. Analysis performed for the NEWIS indicates that these effects, and hence the case for implementation of a wind power forecast, grows as wind power penetrations increase. Intra-day wind forecasting should also be performed in order to reduce dispatch inefficiencies and provide for situational awareness.

It would also be beneficial for ISO-NE to publish the day-ahead wind forecast along with the day-ahead load forecast, as this would contribute to overall market efficiency. Current practices for publishing the load forecast should be followed for publishing the wind forecast, subject to confidentiality requirements. This allows generation market participants to see the net load forecast and bid accordingly, just as they do with load today (See Section 5.2.4).

Wind Generation and Dispatch: Production simulation results showed increased hours of minimum generation conditions as wind penetration increases, which, given the policy support schemes for wind generation, implies increased frequency of negative LMPs. ISO-NE should not allow wind plants to respond in an uncontrolled manner to negative LMPs (e.g., as self-scheduled resources). Doing so may cause fast and excessive self-curtailment of wind generation. That is, due to their rapid control capability, all affected wind plants could possibly reduce their outputs to zero within a few minutes of receiving an unfavorable price signal. ISO-NE should consider adopting a methodology that sends dispatch signals to wind plants to control their output in a more granular and controlled manner (e.g., with dispatch down commands or specific curtailment orders). This method is recommended in the Task 2 report. NYISO has already implemented a similar method (See Section 5.2.1 for a discussion on the frequency of minimum generation issues.).

System Flexibility: Increased wind generation will displace other supply-side resources and reduce flexibility of the dispatchable generation mix—in a manner, which is system specific. Any conditions that reduce the system flexibility will potentially, negatively impact the ability of New England to integrate large amounts of wind power. Factors that could potentially reduce system flexibility can be market, regulatory, or operational practices, or system conditions that limit the ability of the system to use the flexibility of the available resources and can include such issues as: strict focus on (and possibly increased regulation of) marginal emissions rates as compared to total overall emissions, decreased external transaction frequency and/or capability, practices that impede the ability of all resources to provide all types of power system products within each resource’s technical limits, and/or long-term outages of power system equipment or chronic transmission system congestion.

Strict focus on marginal emissions rates can reduce system flexibility by encouraging generators to operate in a manner that reduces their flexibility (e.g., reducing allowed ramp rates or raising minimum generation levels in order to limit marginal emissions rates) and ignores the fact that as non-emitting resources are added to the system the overall level of emissions is reduced. Due to the variability and imperfect predictability of resources like wind power, dispatchable resources may need to be utilized in different operational modes that in some instances and/or during some hours may actually increase these units' emissions rates (in terms of tons of emittant per MWh of electrical energy), however the total emissions of the system will be reduced. The effects of the increases in marginal emissions rates are expected to be several orders of magnitude smaller than the effect of the overall reductions in emissions. Reduced frequency and/or capability of external interchange limits the ability of balancing areas to share some of the effects of wind power's variability and uncertainty with neighboring systems that at any given time might be better positioned to accommodate these effects. Practices that limit the ability of resources to participate in the power system markets to the full extent of their technical capability may cause the system to operate in a constrained manner, which reduces system flexibility. Self-scheduled generation reduces the flexibility of the dispatchable generation resource and can lead to excessive wind curtailment at higher penetrations of wind generation. It is recommended that ISO-NE examine its policies and practices for self-scheduled generation, and possibly change those policies to encourage more generation to remain under the control of ISO-NE dispatch commands. System flexibility can also be negatively impacted due to expected as well as unforeseen operational conditions of the system that reduce the ability to access and/or utilize the technical flexibility of the system resources. Examples of operational conditions that can negatively impact system flexibility include the long-term outage of resources that provide a large portion of the flexibility on the system, and chronic transmission system congestion or stability and/or voltage constraints along important transmission corridors.

Operating Records: It is recommended that ISO-NE record and save sub-hourly data from existing and new wind plants. System operating records, including forecasted wind, actual wind, forecasted load, and actual load should also be saved. Such data will enable ISO-NE to benchmark actual system operation with respect to system studies. ISO-NE should also periodically examine and analyze this data to learn from the actual performance of the ISO-NE system.

7.7 Other Observations from Study Results

Flexible Generation: The ISO-NE system presently has a high percentage of gas-fired generation, which can have good flexibility characteristics (e.g., ramping, turn-down). Using the assumed system, the results showed adequate flexible resources at wind energy penetration levels up to 20%. Also using the assumed system, there are periods of time in the 24% wind energy scenario when much of the natural-gas-fired generation is displaced by the wind generation, leaving less flexible coal and nuclear operating together with the wind generation. In this study, physical limits were used to determine how much units could be turned down when system conditions required such action. ISO-NE will need to be diligent in monitoring excessive self-scheduling, which could limit the apparent flexibility of the generation fleet. ISO-NE may need to investigate operating methods and/or market structures to encourage the generation fleet to make its physical flexibility available for system operations (See Section 5.2.1.2).

Energy Storage: Study results showed no need for additional energy storage capacity on the ISO-NE system given the flexibility provided by the assumed system. However, the need for energy storage may increase if there is attrition of existing flexible resources needed to balance net load and dispatchable resources. It is commonly believed that additional storage is necessary for large-scale wind integration. In New England, wind generation displaces natural-gas-fired generation during both on-peak and off-peak periods. Natural-gas-fired generation remains on the margin, and the periodic price differences are usually too small to incent increased utilization of pumped storage hydro-type energy storage, which is why the study results showed PSH utilization increasing only slightly and only at higher levels of wind penetration.

Additional energy storage may have some niche applications in regions where some strategically located storage facilities may economically replace or postpone the need for transmission system upgrades (i.e., mitigate congestion). Also, minute-to-minute type storage may be useful to augment existing regulation resources. But additional large-scale economic arbitrage type storage, like PSH, is likely not necessary (see Section 5.2.1).

Displacement of Energy from Conventional Generation: Energy from wind generation in New England primarily displaces energy from natural-gas-fired generation. Although displacement of fossil-fueled generation might be one of the objectives of regional energy policies, a consequence is that it may radically change the market economics for all resources on the system, but especially for the natural-gas-fired generation resources that are displaced. Although their participation in the ISO-NE market will continue to be important, to serve both energy (especially during summer high-load periods) and capacity requirements, the balance of revenues that resources receive from each of these market segments will change. Since total annual energy output from conventional resources would decline and energy prices also would decline under the study assumptions, capacity prices from these plants will likely need to increase if they are to remain economically viable and therefore able to provide the flexibility required for efficient system operation (See Section 5.2.1).

Dynamic Scheduling: Dynamic scheduling involves scheduling the output of a specific plant or group of plants in one operating area on transmission interties to another operating area. Dynamic scheduling implies that the intertie flows are adjusted on a minute-to-minute basis to follow the output of the dynamically scheduled plants. Most scenarios in this study included all necessary New England wind resources within the ISO-NE operating area, and therefore did not require dynamic scheduling. The Maritimes scenarios assumed that a portion of the ISO-NE wind generation would be imported from wind plants in the Canadian Maritimes using dynamic scheduling, so that ISO-NE would balance the variability due to the imported wind energy. The results showed, given the study assumptions, that ISO-NE has adequate resources to balance the imported Maritimes wind generation.

Load and Distributed Wind Forecasting: This study assumed that load forecast accuracy would remain the same as wind penetration increases. However, a portion of the wind generation added to the ISO-NE system will be distributed generation that may not be observed or controlled by ISO-NE. It will essentially act as a load-modifier. As such, distribution-connected wind generation will negatively affect the accuracy of load forecasts. As long as the amount of this distribution-connected wind-generation is fairly small and if ISO-NE is able to account for the magnitude and location of distribution-connected wind plants, it should be possible to include a correction term into the load forecasting algorithm (see Section 5.3.3).

7.8 Technical Requirements for Interconnection of Wind Generation

The Task 2 report, "Technical Requirements for Wind Generation Interconnection and Integration," includes a set of recommendations for interconnecting and integrating wind generation into the ISO-NE power grid. That report was completed before the statistical, production simulation, and reliability analyses of the NEWIS scenarios were performed. The recommendations contained in the Task 2 report were re-examined after the NEWIS scenario analysis was completed and the analysis performed reinforces the need to implement those recommendations. It was determined that no changes to the Task 2 recommendations are warranted at this time based on the results of the scenario analysis. A few of the most significant Task 2 recommendations are summarized below.

Active Power Control: Wind plants must have the capability to accept real-time power schedule commands from the ISO for the purpose of plant output curtailment. Such control would most often be used during periods when wind generation is high and other generating resources are already at minimum load.

AGC Capability: Wind plants should be encouraged to have the capability to accept Automatic Generation Control (AGC) signals, which would enable wind plants to provide regulation. The current ISO-NE market product requires symmetrical regulation, which means that wind generation could only provide this service when it is curtailed. Some other systems have asymmetrical regulation markets where wind generation could be quite effective at down-regulation even under non-curtailed operation, such as when other generation resources have been dispatched down to minimum load and/or other down regulation resources have been exhausted.

Centralized Wind Forecast: ISO-NE should implement a centralized wind power forecasting system that would be used in a manner similar to the existing load forecasting system. Information from the day-ahead wind forecast would be used for unit commitment as well as scheduling regulation and reserves. ISO-NE should also implement intra-day forecasting (e.g. an early warning ramp forecasting system) that will provide improved dispatch efficiency and situational awareness, and alert operators to the likelihood and potential magnitude and direction of wind ramp events.

Communications: Wind plants should have the same level of human operator control and supervision as similar sized conventional plants. Wind plants should also have automated control/monitoring functions, including communications with ISO-NE, to implement operator commands (active/reactive power schedules, voltage schedules, etc.) and provide ISO-NE with the data necessary to support wind forecasting functions. The Task 2 report contains detailed lists of required signals.

Capacity Value: Given that only three years of data were available for the LOLE calculation and that the results of this method can vary somewhat from year to year, it is recommended that ISO-NE should monitor a comparison between its current approximate method and the ELCC method for determining the aggregate capacity value of all wind generation facilities in the operating area, and the calculation should be updated periodically as operational experience is gained. Historical data should be used for existing plants; data from mesoscale simulations could be used for new plants until sufficient operation data is available.

If the recommendations developed and discussed in the Task 2 report are not implemented, it is highly likely that operational difficulties will emerge with significant amounts of wind generation. Two recent examples of some Balancing Authorities experiences with a lack of effective communication and control and/or a lack of an effective wind power forecast and the resulting operational difficulties include having to:

- Implement load-shedding[76] (albeit contracted-for load-shedding), and
- Spill water for hydro resources.[77]

Another example of operational difficulties that could arise includes the experience of some European TSO's with older windplants' lack of ability to participate in voltage control causing the system to sometimes be operated in very inefficient dispatch modes. This lack of voltage control participation, as well as the lack of communication and control capability, was found to have exacerbated the severe European UCTE disturbance in November of 2006[78].

7.9 Future Work

Several areas of interest that are candidates for further investigation are suggested by the study results. These include:

Transmission system overlay refinement. The transmission system overlays developed for the Governors' Study and used in this study were shown, based on thermal limit analysis only, to have adequate capacity for all scenarios. In fact, some NEWIS scenarios use transmission overlays that were "one size smaller" than those used for the Governors' Study scenarios, and still no or only minimal congestion was observed. Detailed and extensive transmission studies that include stability and voltage limits will be required in order to proceed with specific wind projects or large-scale wind integration.

A future study could start by analyzing wind penetration scenarios using a "copper sheet" approach to evaluate magnitude and duration of congestion due to existing transmission limitations. This would guide the design of specific transmission additions to minimize congestion with increased levels of wind generation.

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[76] ERCOT Event on February 26, 2008: Lessons Learned, available at: http://www1.eere.energy.gov/windandhydro/pdfs/43373.pdf.

[77] "Wind power surge forces BPA to increase spill at Columbia Basin dams" available at: http://www.oregonlive.com/environment/index.ssf/2008/07/columbia_basin_river_managers.html

[78] Final report: System Disturbance on 4 November 2006, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf

Sub-hourly performance during challenging periods. A more in-depth investigation of the dynamic performance of the system under conditions of high stress, such as coincident high penetration and high variability could be pursued using additional simulation tools that have been developed recently. Both long-term dynamic (differential equations) simulations and fine time resolution quasi-static time simulations could shed additional insight into the frequency, ACE, CPS2 and other performance measures of the system, as well as providing more quantitative insight into incremental maneuvering duties imposed on the incumbent generation and the impacts of this increased maneuvering on such quantities of interest as emissions and increased generator maintenance. Such analysis could be part of an assessment of possible increased operating costs associated with maneuvering (beyond those captured in the MAPS analysis).

Impacts of Cycling and Maneuvering on Thermal Units. Costs of starting and stopping units, and static impacts on heat rate were reflected in the study to the extent presently possible. However, the understanding of these impacts and the quantification of costs is still inadequate throughout the industry. A deeper quantification of the expected cycling duty, the ability of the thermal generation fleet to respond and an investigation of the costs—O&M, emissions, heat rate, and loss-of-life—would provide clearer guidance for both operating and market design strategies.

Economic Viability and Resource Retirements. The incumbent generating resources, particularly natural-gas-fired generation, will be strongly impacted by large-scale wind generation build-outs like those considered in the study. Investigation should be performed to determine the revenue impacts, and their implications for the long-term viability of the system resources that provide the flexibility required to integrate large-scale wind power. Such investigation could include examination of impact of possible resource retirements driven by reduced energy sales and revenues, and the efficacy of possible market structures for maintaining the necessary resources to maintain system reliability.

Demand Response. A deeper analysis of the efficacy and limitations of various demand-side options for adding system flexibility could help define directions and policies to pursue. Temporal aspects of various demand response options could be further investigated. For example, heating and cooling loads have significant time and duration constraints that will govern their effectiveness for different classes of response. Similarly, some types of commercial and industrial loads may offer options and limitations for providing various ancillary services that will be needed.

Weather, Production, and Forecasting Data. This study was based on sophisticated meso-scale wind modeling. The ISO should start to accumulate actual field data from operating wind plants, from met masts, and from actual. Further investigation and refinement of study results or use of such data in the suggested sub-hourly performance analysis, would increase confidence in results and may allow for further refinement of ISO plans and practices.

Network Planning Issues. This study was not a transmission planning study. The addition of significant wind generation, particularly multiple plants in close electrical proximity in parts of the New England grid that may be otherwise electrically remote (for example the addition of significant amounts of wind generation in Maine) poses a spectrum of application questions. A detailed investigation of a specific subsystem within New England considering local congestion, voltage control and coordination, control interaction, islanding risk and mitigation, and other engineering issues that span the gap between “interconnection” and “integration” would provide insight and help establish a much needed set of practices for future planning in New England (and elsewhere).

Appendix A – Extended Validation

Table A1 **Wind speed validation sites included in the NEWIS extended validation.**

Site	Eastern Wind Dataset Site Number	Distance from Site (km)	Period of Record
Eastern ME	4677	82.55	1/04-1/08
Central NY 1	5103	2.71	7/03-6/07
Central NY 2	5103	0.89	11/02-6/07
Northern NY	4594	0.35	8/02-6/07
Western NY	5910	19.89	11/03-12/07
Northern VT	3257	14.83	6/03-7/07
Western MA	6241	6.39	11/03-12/06
East Central ME	4677	73.58	7/02-12/08

A1. Wind Speed Validation

Table 1 is a list of the eight validation sites that were used for the extended wind speed validation conducted for the NEWIS by AWST. Included in the Table for each validation site is the number of the Eastern Wind Dataset site (i.e. the "simulated site") nearest to the validation site, the distance between the validation site and Eastern Wind Dataset site pair, and the period of record that wind speeds were measured at the validation sites. Wind speed validation plots for each validation pair (measured versus simulated) are included as Figures 1 through 4 below. These figures contain monthly means and the diurnal cycle (mean values) of each validation pair. For example, Figure 1 contains both the Eastern Maine and Central New York validation sites plotted against their respective simulated sites. As illustrated in Figures 1 through 4, the simulated and measured wind speeds are well-correlated.

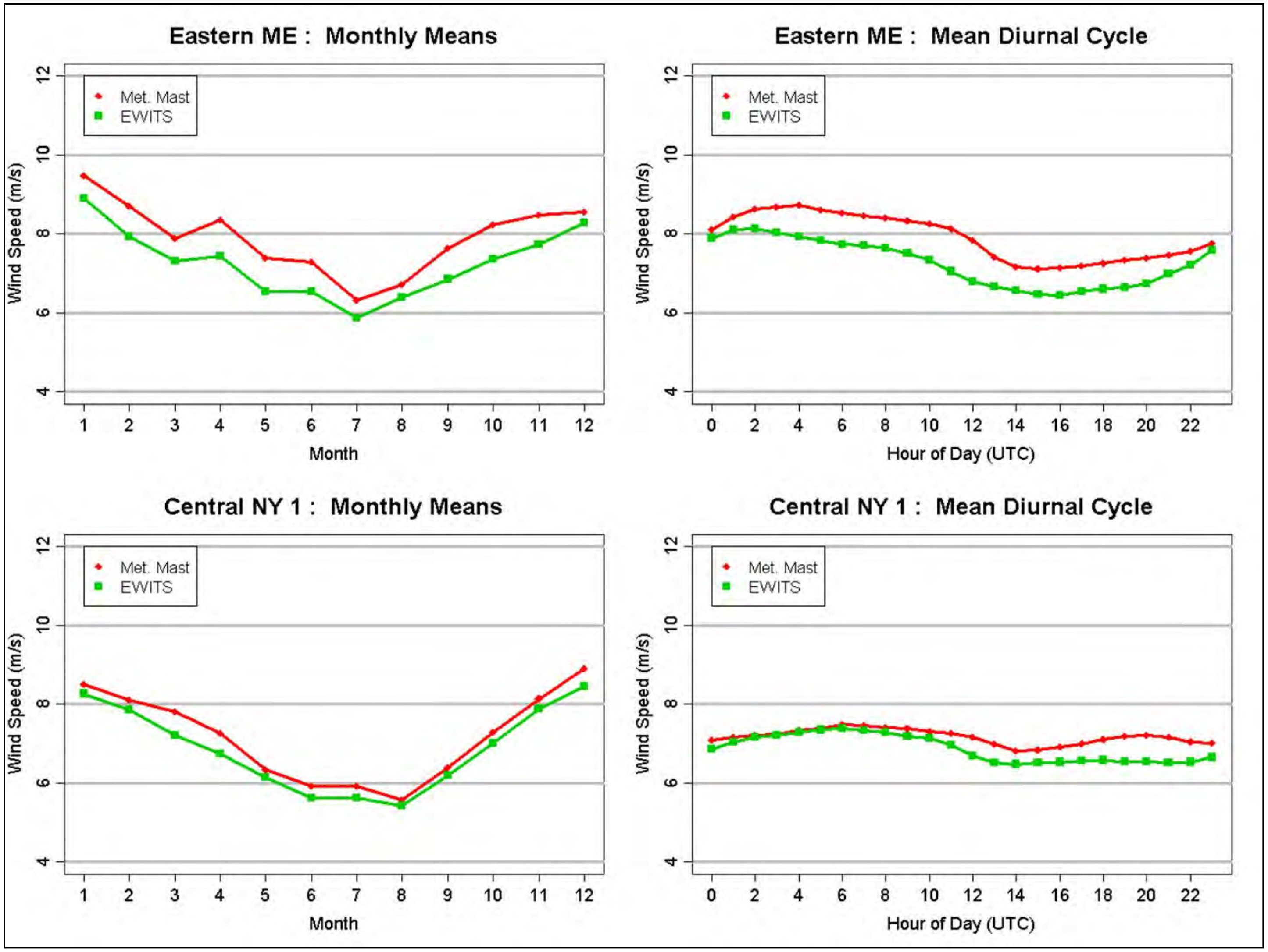


Figure A1 Wind speed validation plots for Eastern Maine and Central New York. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds are red plots represent measured wind speed data collected from tall towers)

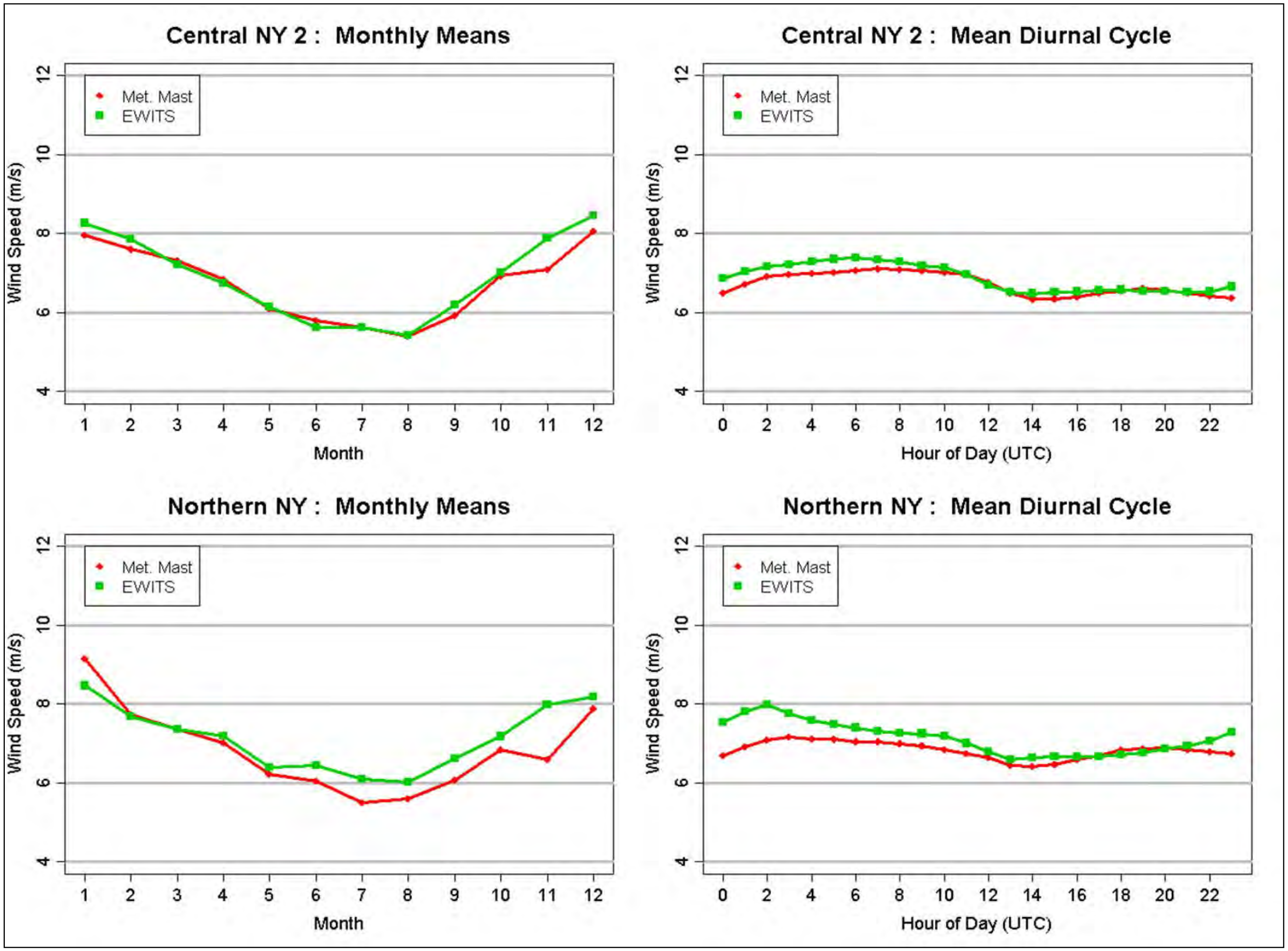


Figure A2 Wind speed validation plots for Central and Northern New York. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds are red plots represent measured wind speed data collected from tall towers)

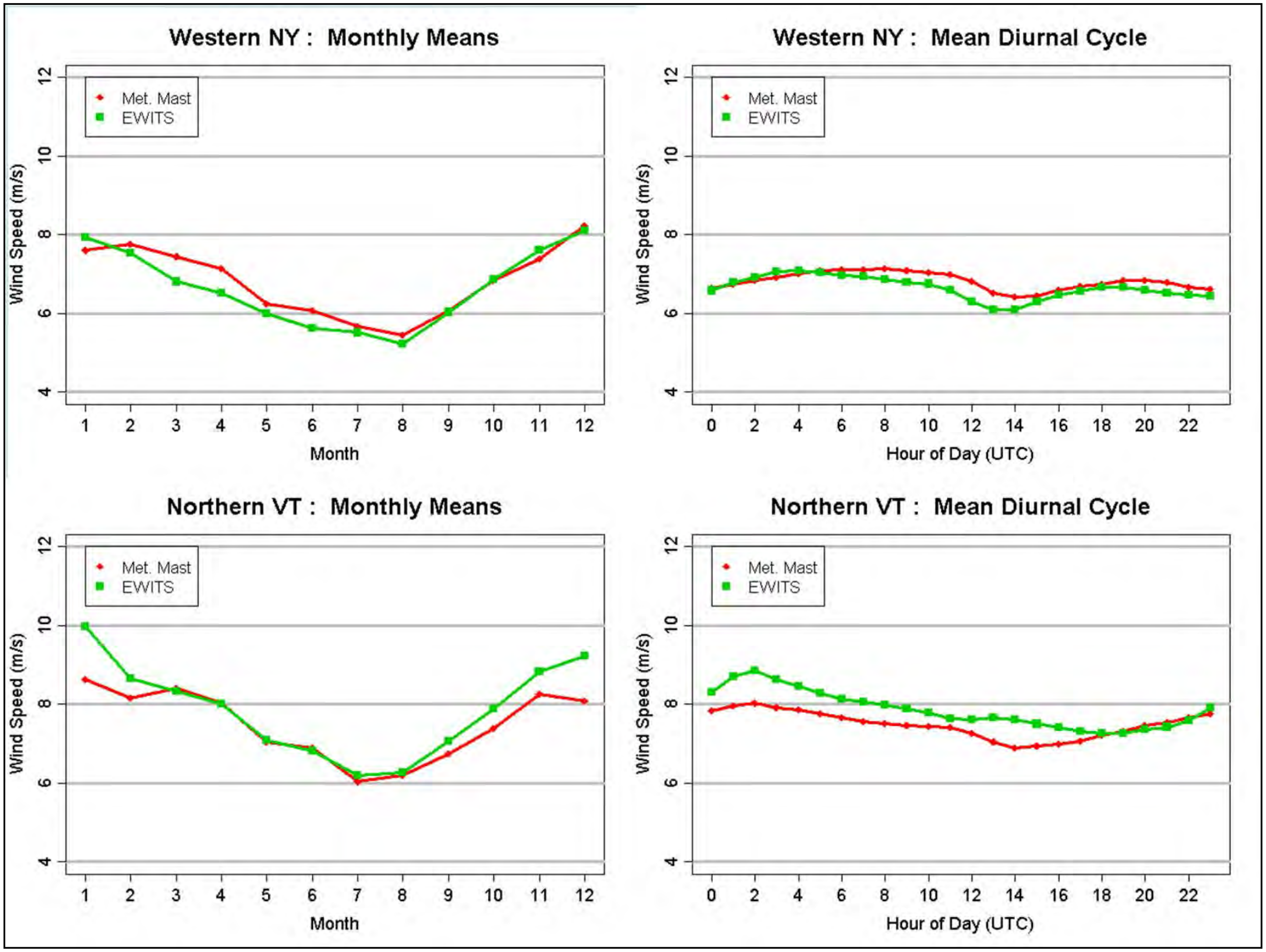


Figure A3 Wind speed validation plots for Western New York and Northern Vermont. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds are red plots represent measured wind speed data collected from tall towers)

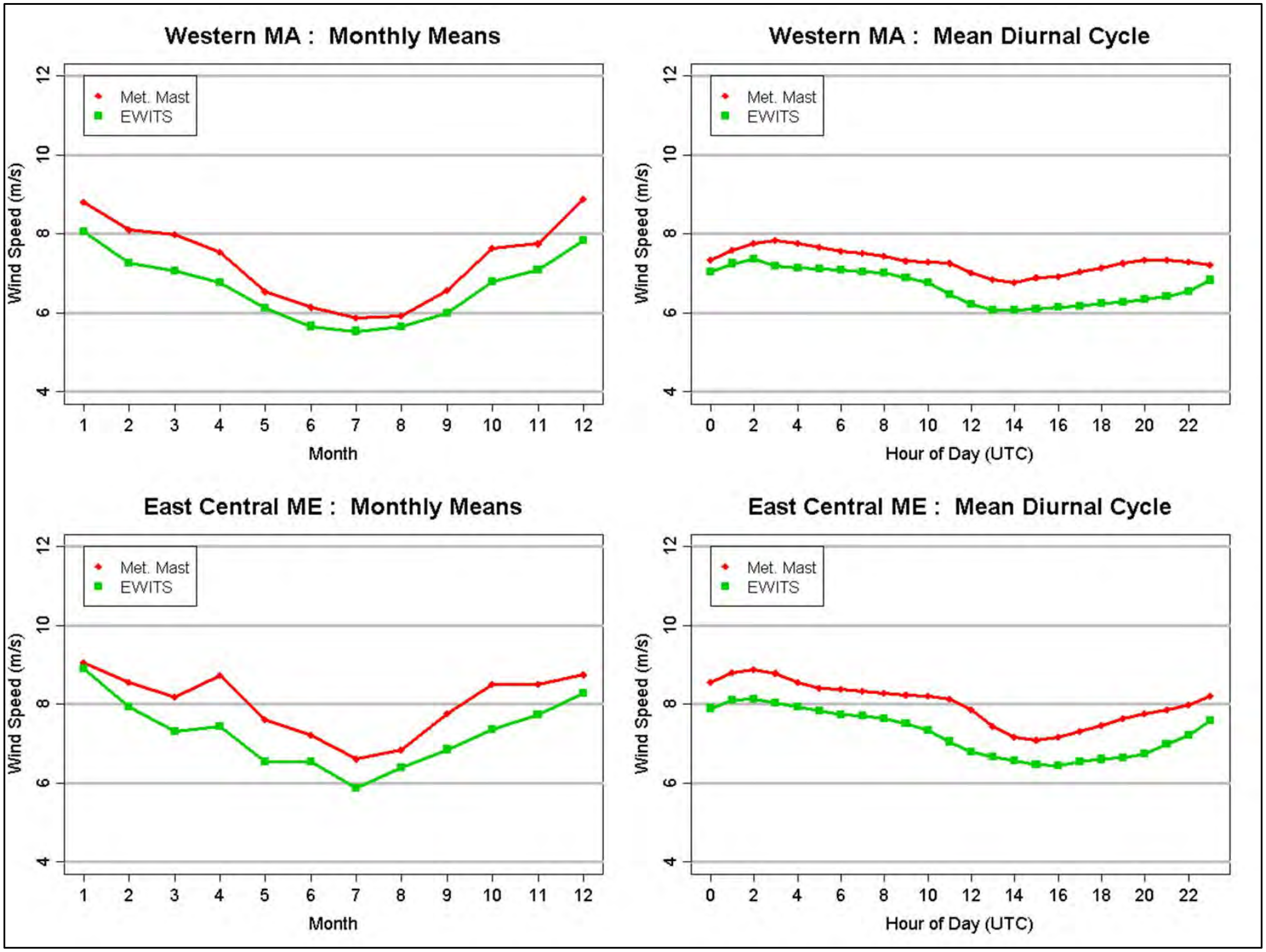


Figure A4 Wind speed validation plots for Western Massachusetts and East Central Maine. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds and red plots represent measured wind speed data collected from tall towers)

Table A2 Power output validation sites included in the NEWIS extended validation

Site	Eastern Wind Dataset Site Number	Distance from Site (km)	Period of Record
Southern VT	3069	16.06	3/03-3/09
Eastern MA 1	7277	35.51	3/03-3/09
Eastern MA 2*	7277	38.36	5/06-3/09
Western NH**	4791	1.34	12/08-3/09
Eastern ME**	4677	82.55	2/09-3/09

Notes: *Diurnal/Monthly cycles compared against EWITS 2004-2006 climatologies
**Diurnal cycle compared from EWITS 2004-2006 climatology of same months

A2. Power Output Validation

Table 2 is a list of the five validation sites that were used for the extended wind plant power output validation conducted for the NEWIS by AWST. Included in the Table for each validation site is the number of the Eastern Wind Dataset site (i.e. the "simulated site") nearest to the validation site, the distance between the validation site and Eastern Wind Dataset site pair, and the period of record that windpower output data were provided for the validation site. Wind plant power validation plots for each validation pair (measured versus simulated) are included as Figures 5 and 6 below. Except where noted, these figures contain monthly means and the diurnal cycle (mean values) of each validation pair. For example, Figure 5 contains both the Southern Vermont and Eastern Massachusetts power validation sites plotted against their respective simulated sites. As Figures 5 and 6 illustrate, the simulated and actual power generation are generally well-correlated.

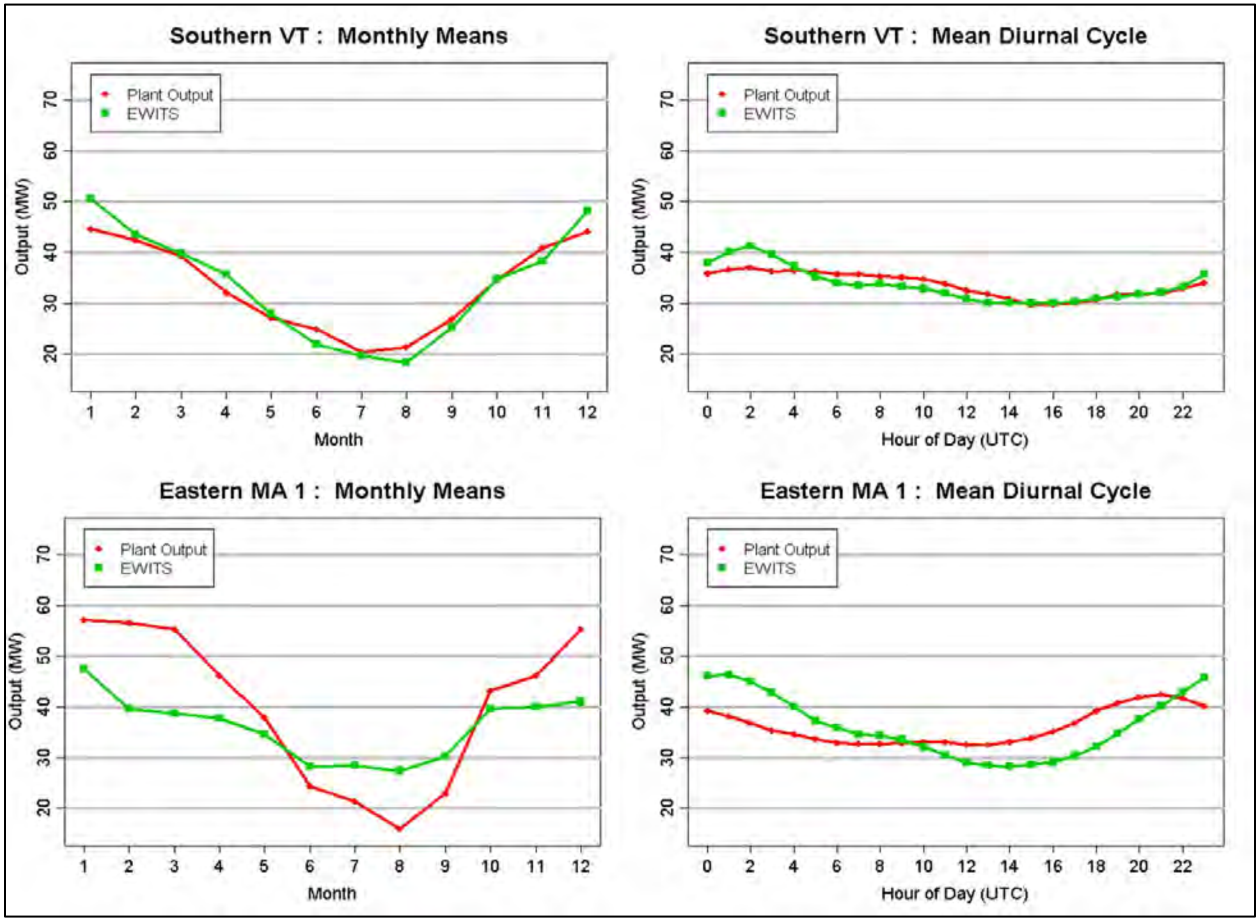


Figure A5 Plant power output validation plots for Southern Vermont and Eastern Massachusetts. (Green plots represent simulated wind plant power output and red plots represent power generation data from existing wind plants)

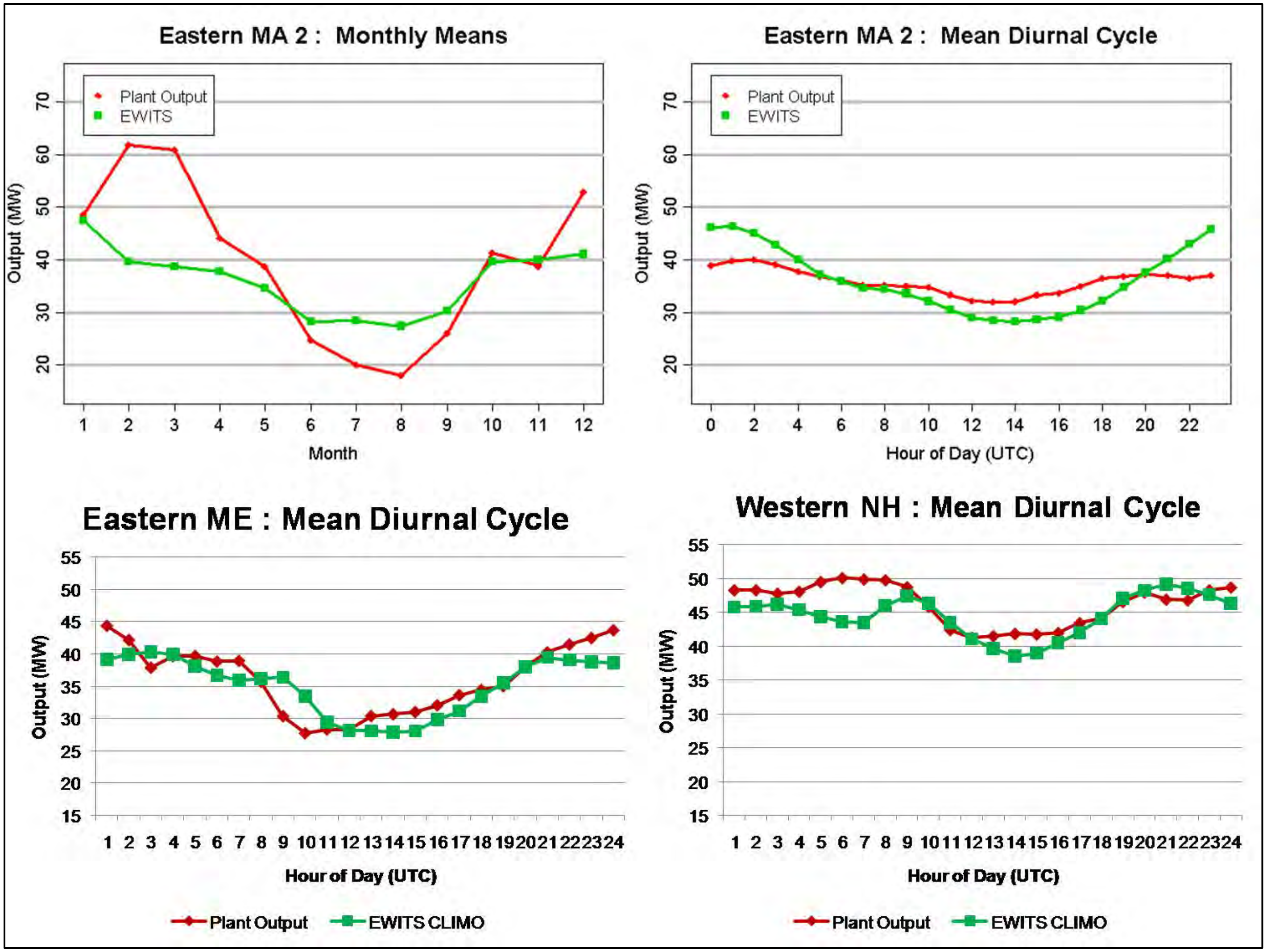


Figure A6 Plant power output validation plots for Eastern Massachusetts, Eastern Maine and Western New Hampshire. (Green plots represent simulated wind plant power output and red plots represent power generation data from existing wind plants)

Appendix B – Additional MAPS results

B. Additional MAPS Results

B.1 14% Scenarios

The following section compares the impact of 14% wind penetration on the ISO-NE system for the 5 different scenarios describes in Chapter 3. The results were done using 2006 load and wind shapes, an unbiased State-of-the-Art (S-o-A) day ahead forecast of the wind generation and a constrained transmission system. Any variations will be noted.

Note that the "Balanced Case" is also referred to as the "Best Site" scenario.

Table B–1 14% penetration scenario comparison

Scenario	3 Year Average Wind Energy (GWh)	2006 Wind Energy (GWh)
14% Energy_Best Sites Onshore	20,342	20,159
14% Energy_Best Sites Offshore	20,342	20,498
14% Energy_Best Sites	20,342	20,421
14% Energy_Best Sites by State	20,342	20,314
14% Energy_Best Sites Maritimes	20,342	20,157

Table B–2 Wind Curtailment 14% Energy

Scenario	Curtailment (GWh)	% Total Energy
14% Energy_Best Sites Onshore	0.31	0.002%
14% Energy_Best Sites Offshore	0.00	0.000%
14% Energy_Best Sites	0.00	0.000%
14% Energy_Best Sites by State	2.61	0.013%
14% Energy_Best Sites Maritimes	0.74	0.004%

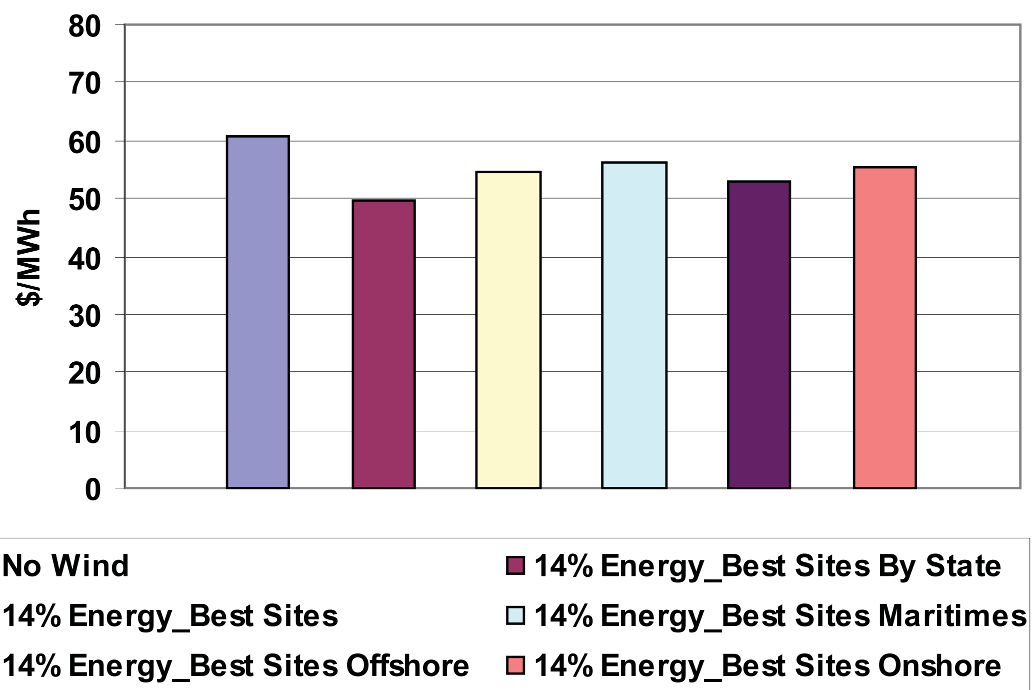


Figure B–1 Annual load weighted average ISO-NE location market price, S-O-A Forecast, 14% penetration

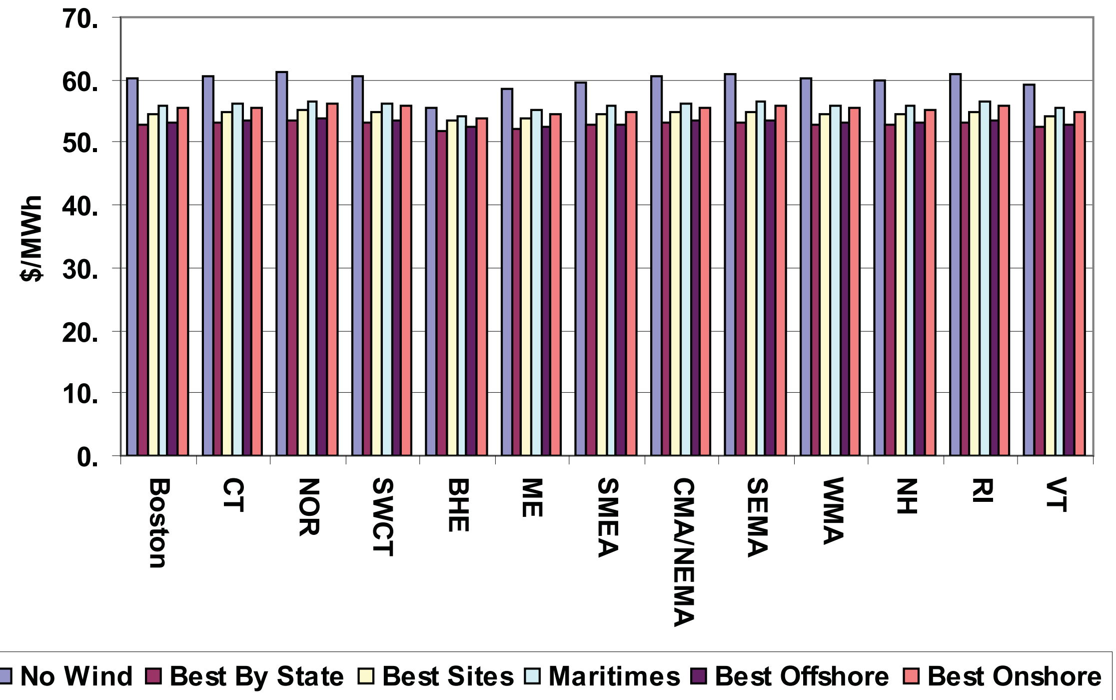


Figure B–2 Annual load weighted average ISO-NE RSP location market price, S-o-A Forecast, 14% penetration

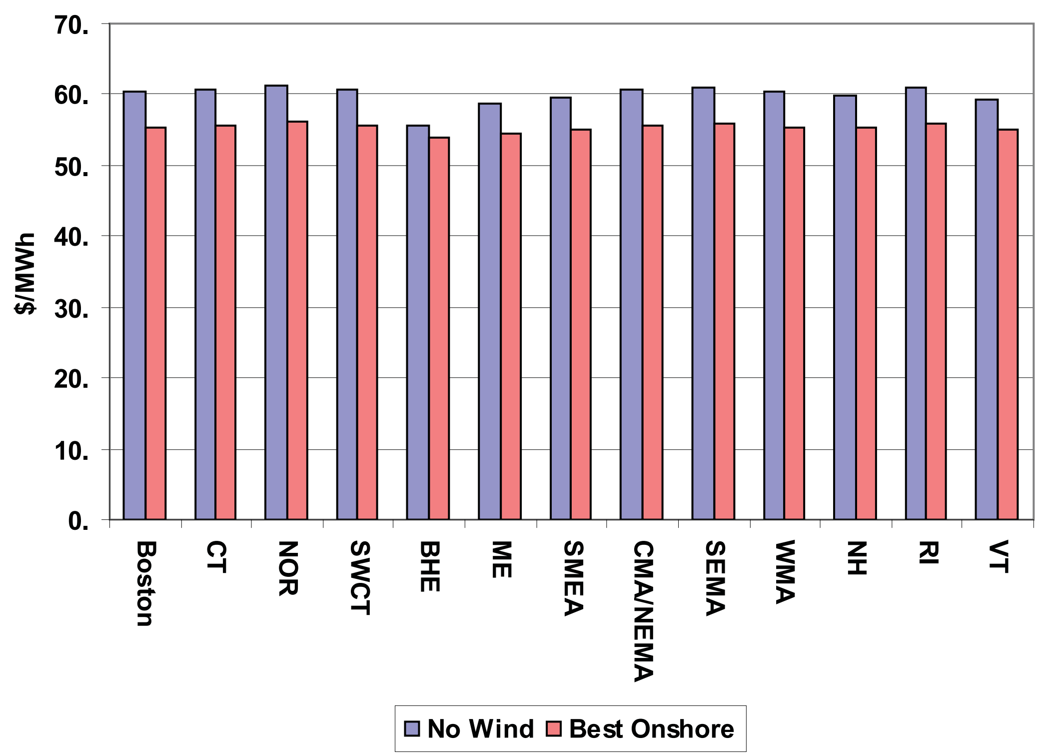


Figure B–3 Annual load weighted average ISO-NE RSP location market price, S-o-A Forecast, 14% penetration No wind, Best Onshore

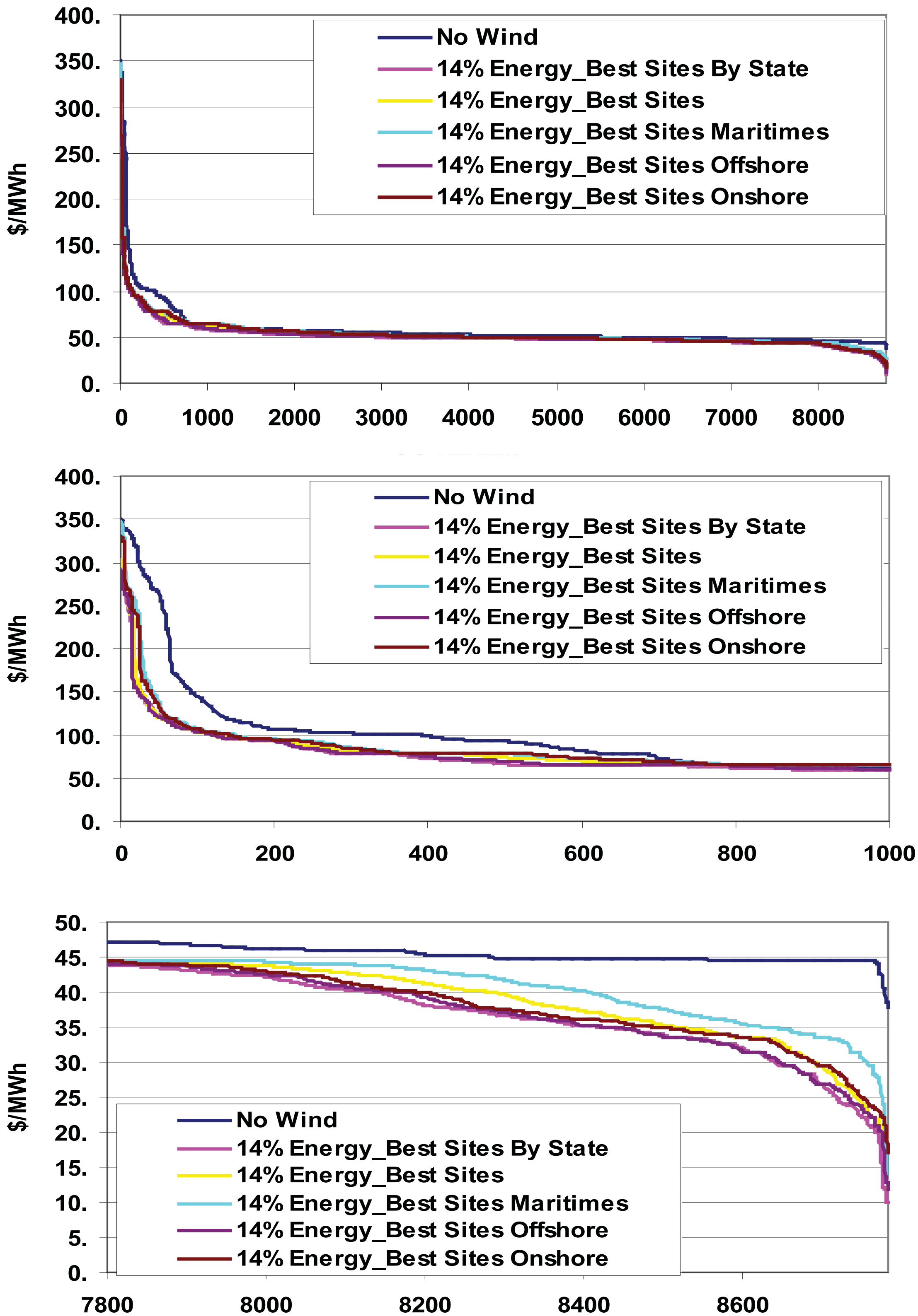


Figure B–4 Annual LMP duration curve, S-O-A Forecast, 14% penetration

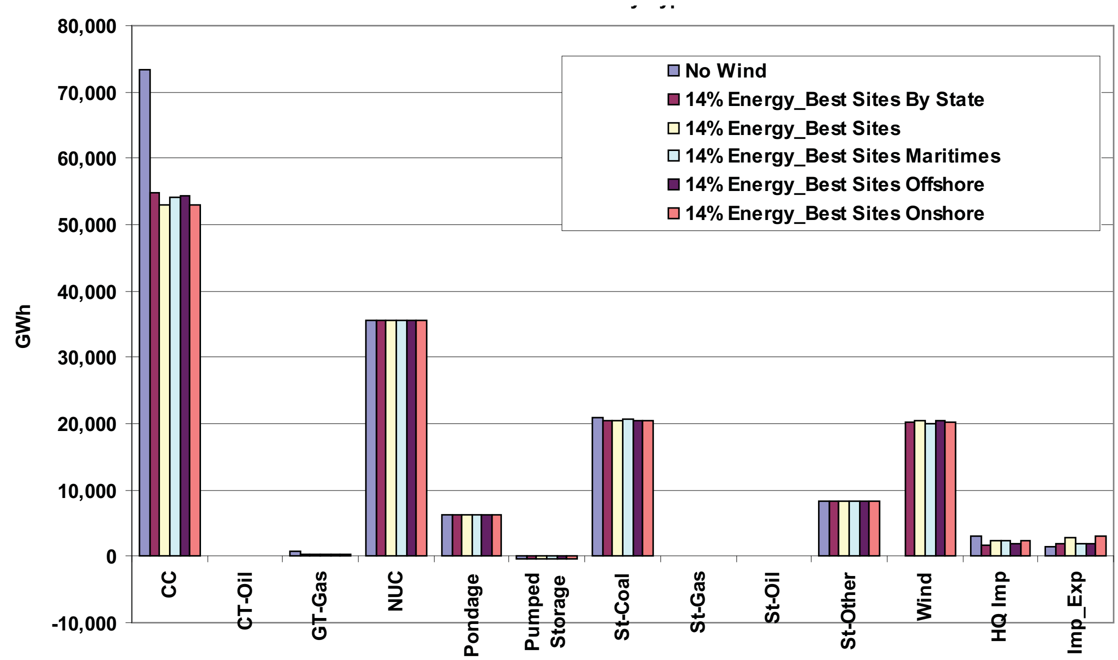


Figure B–5 ISO-NE generation by type, S-o-A forecast, 14% penetration

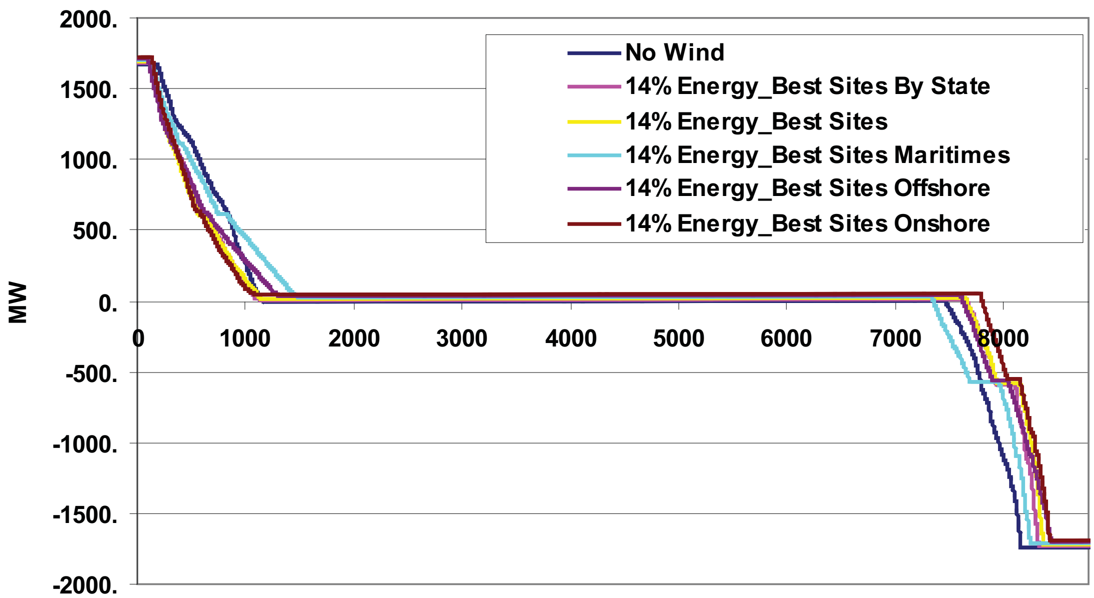


Figure B–6 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, 14% penetration

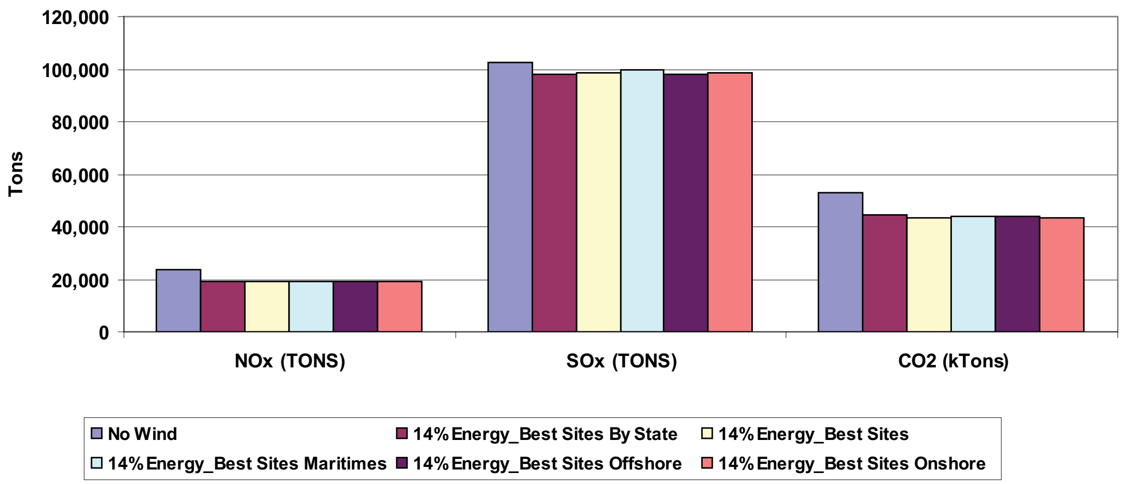
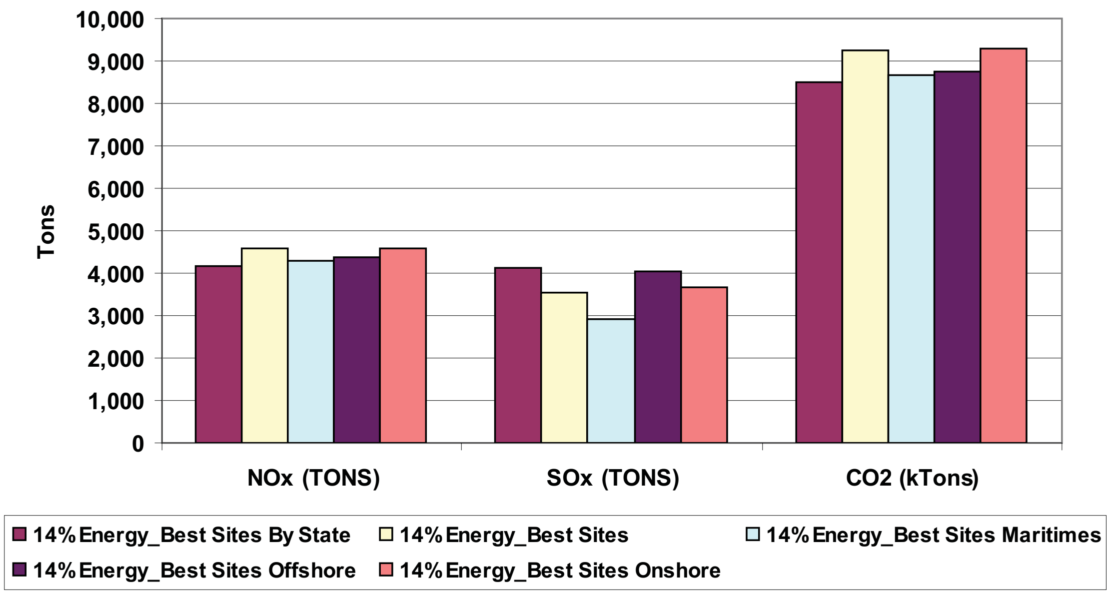


Figure B–7 ISO-NE Total Emissions, S-o-A forecast, 14% penetration



FigureB–8 ISO-NE Total emissions reduction, S-o-A forecast, 14% penetration

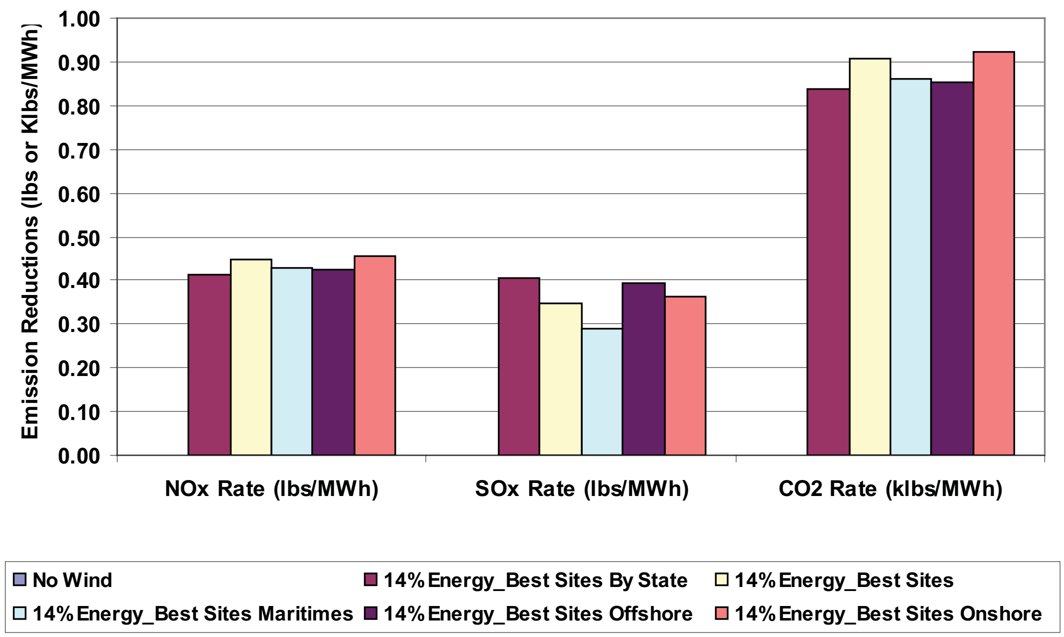


Figure B–9 ISO-NE total emission reduction per MWh of wind generation, S-o-A forecast, 14% penetration

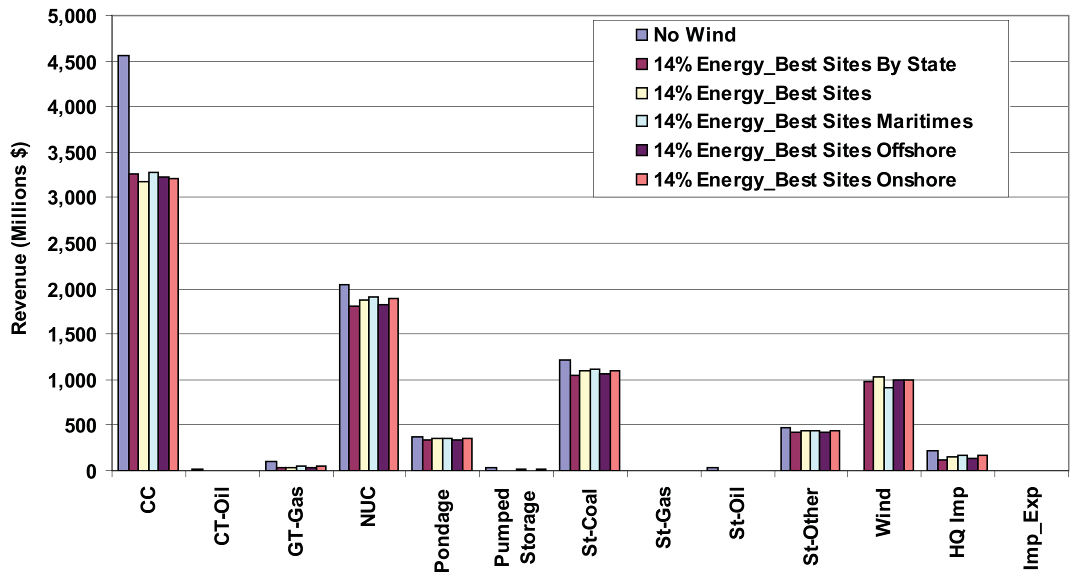


Figure B–10 ISO-NE revenue by type, S-o-A forecast, 14% penetration

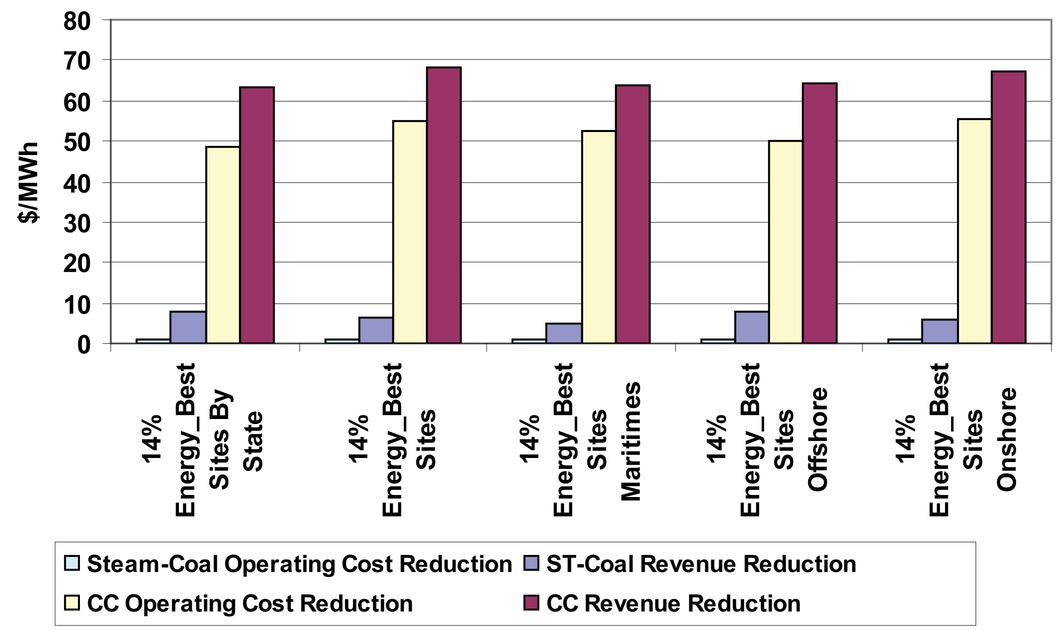


Figure B–11 ISO-NE CC and St-coal revenue and operating cost reduction per MWh of wind generation, S-o-A forecast, 14% penetration

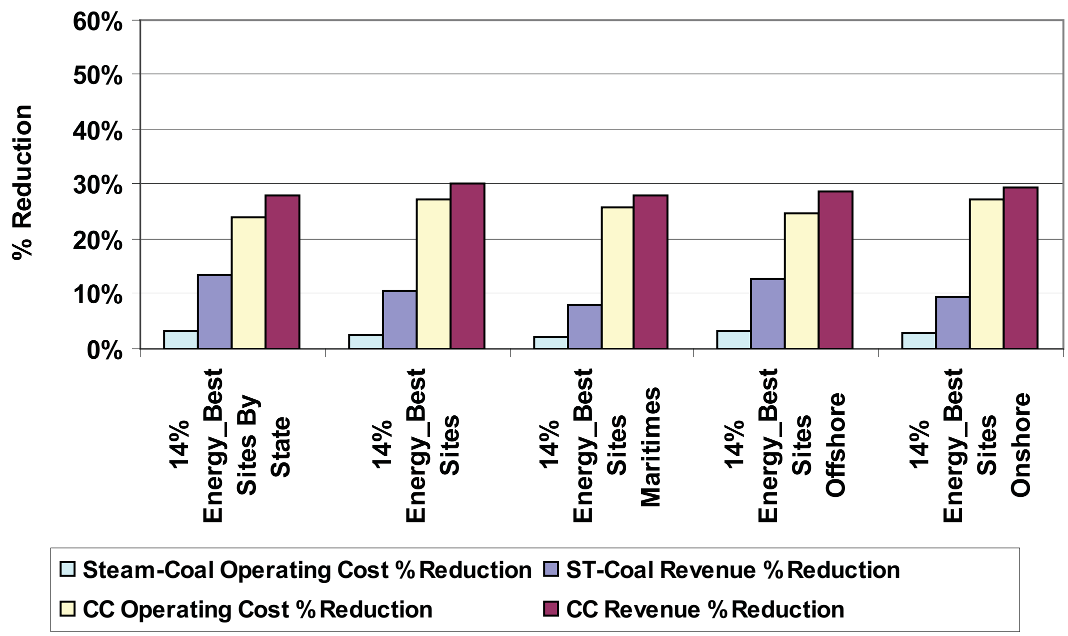


Figure B–12 ISO-NE CC and St-coal revenue and operating cost percent reduction per MWh of wind generation, S-o-A forecast, 14% penetration

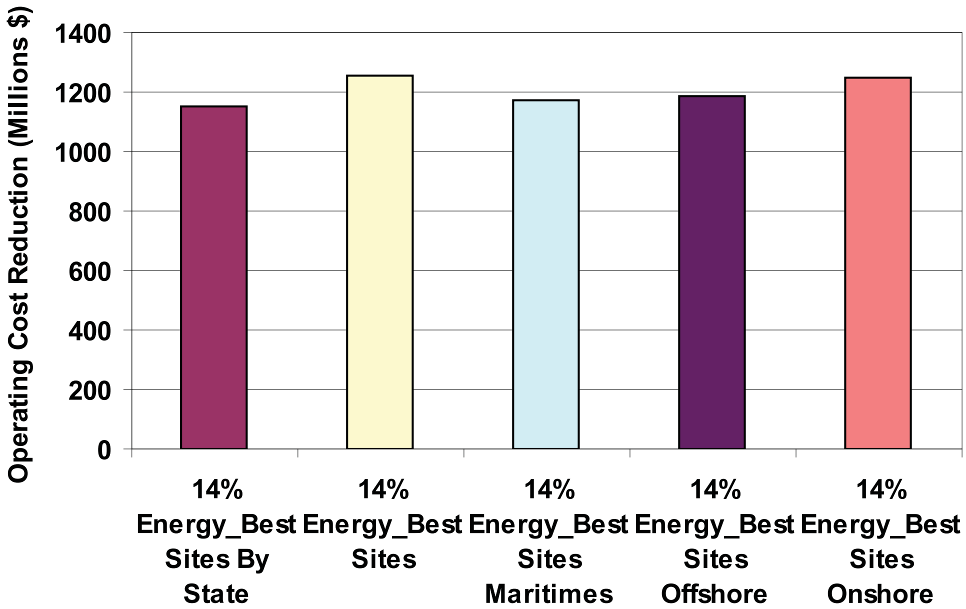


Figure B–13 ISO-NE operating Cost reduction, S-o-A forecast, 14% penetration

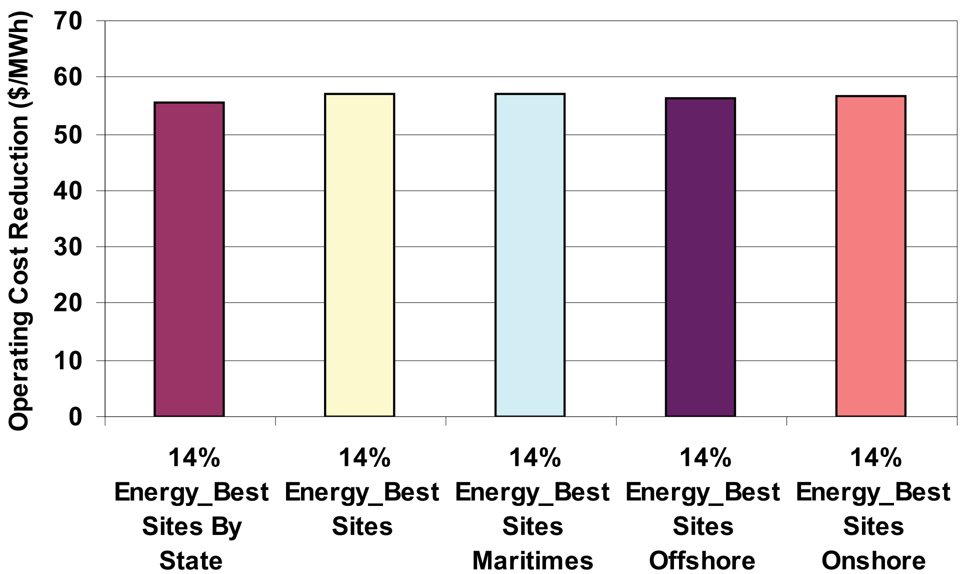


Figure B–14 ISO-NE operating cost reduction per MWh of wind generation, S-o-A forecast, 14% penetration

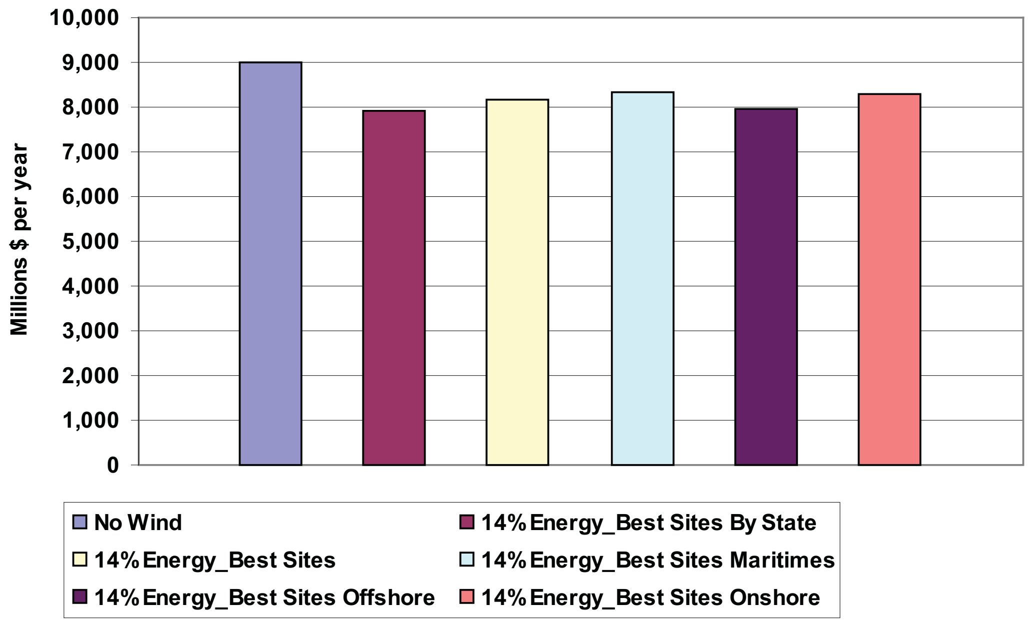


Figure B–15 ISO-NE wholesale load payments for energy, S-o-A forecast, 14% penetration

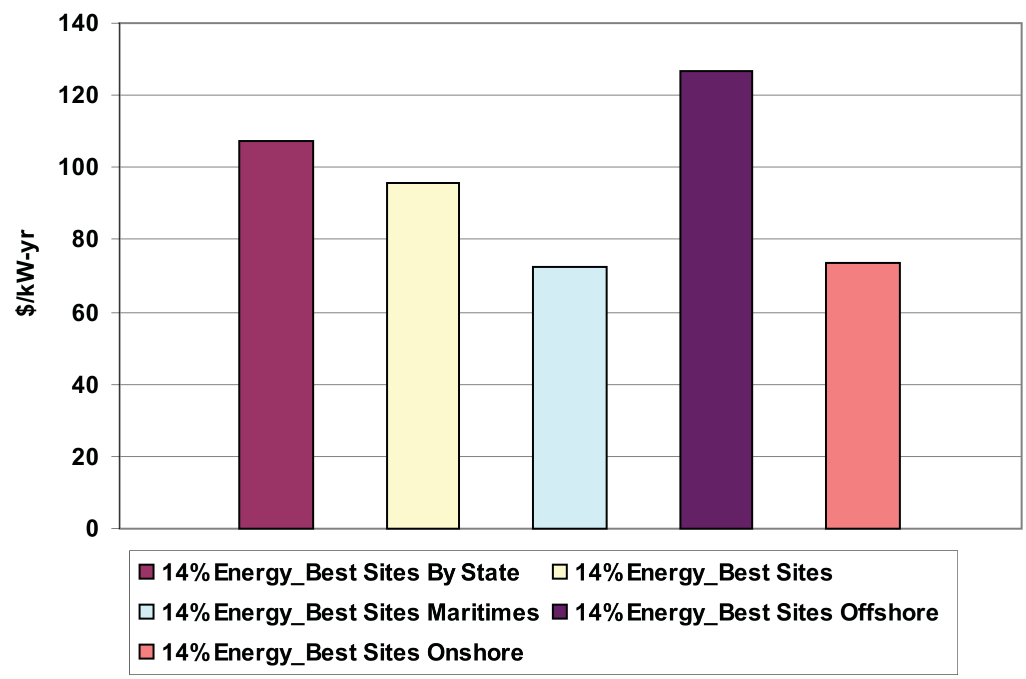


Figure B–16 ISO-NE wholesale load payment for energy reduction per kW of wind, S-o-A forecast, 14% penetration

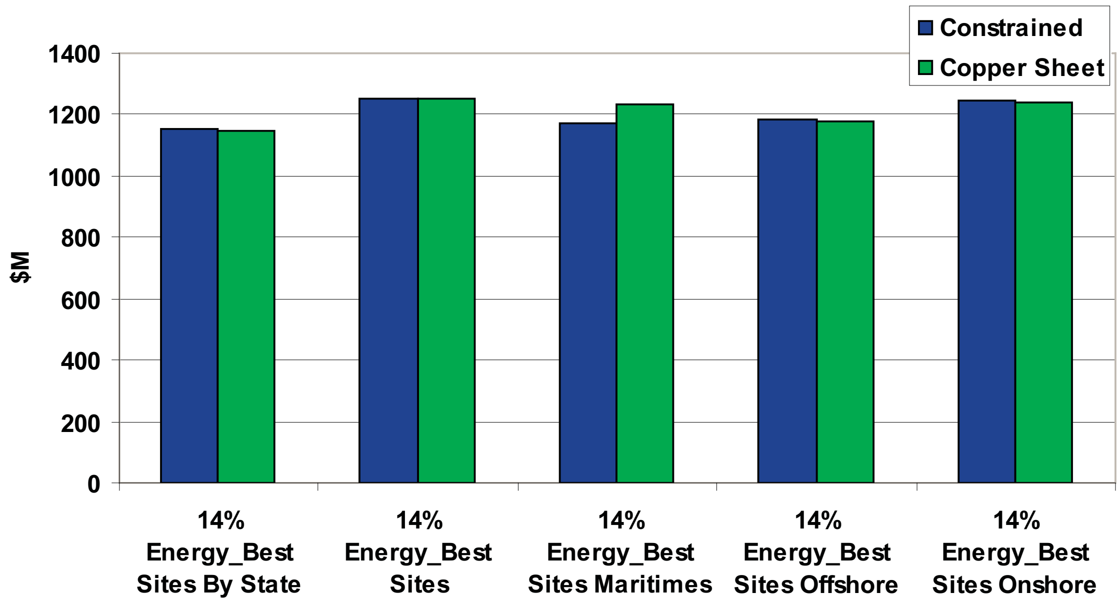


Figure B–17 Impact of transmission on ISO-NE Operating cost reduction, S-o-A forecast, 14% penetration

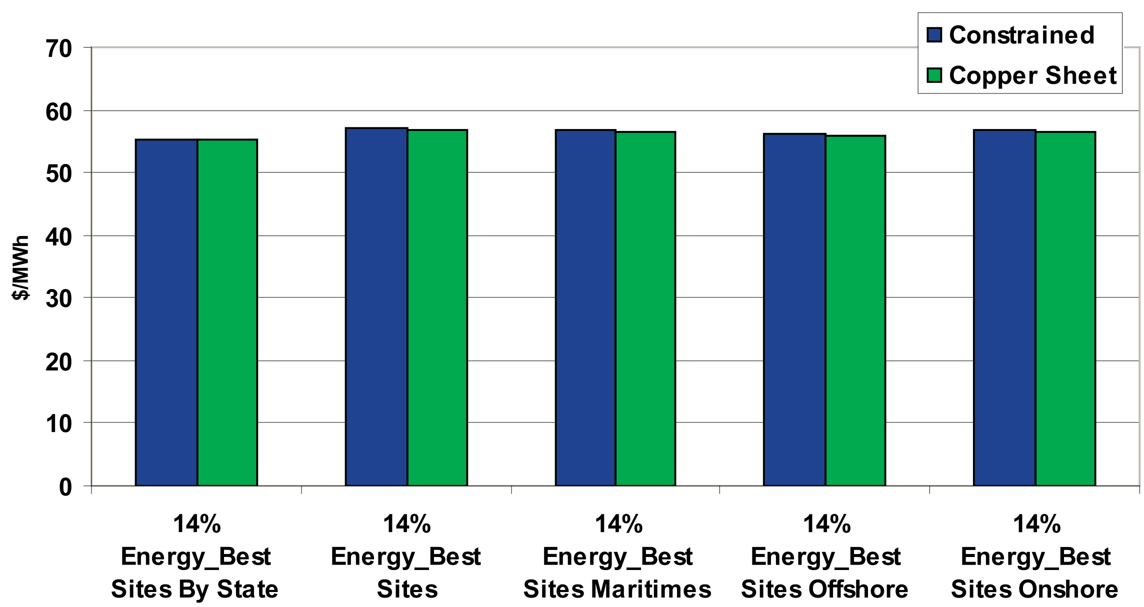


Figure B–18 Impact of transmission on ISO-NE operating cost reduction per MWh of Wind generation, S-o-A forecast, 14% penetration

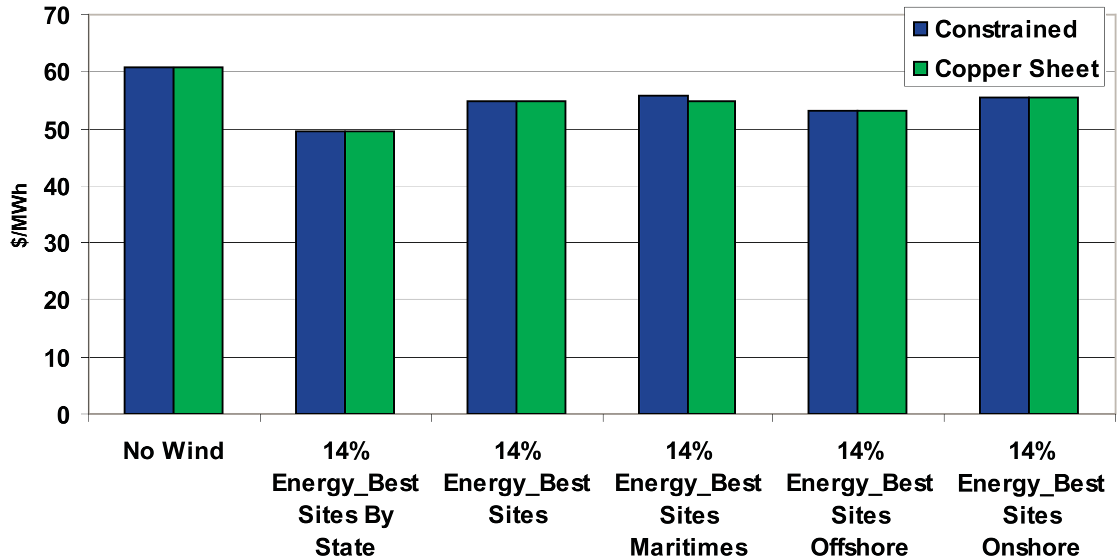


Figure B–19 Impact of transmission on ISO-NE Load Weighted Average LMP, S-o-A forecast, 14% penetration

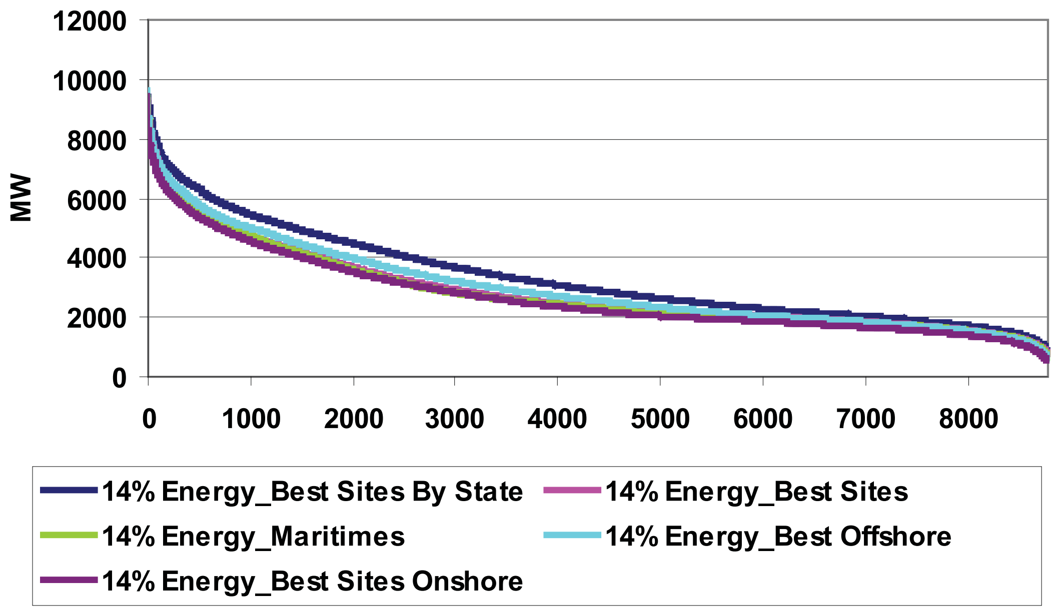


Figure B–20 Hourly range up capability, S-o-A forecast, 14% penetration

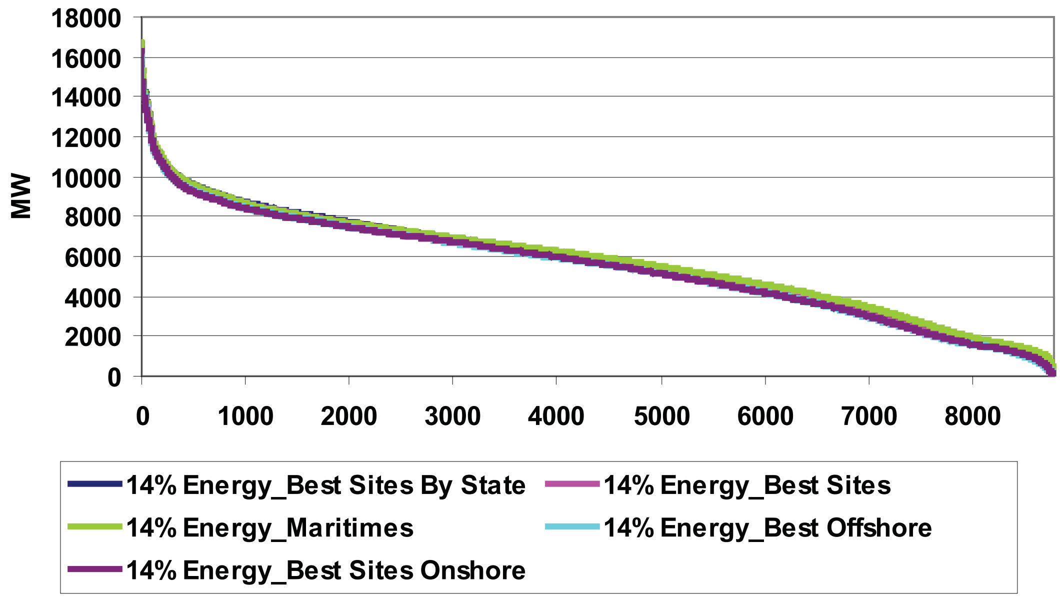


Figure B–21 Hourly range down capability, S-o-A forecast, 14% penetration

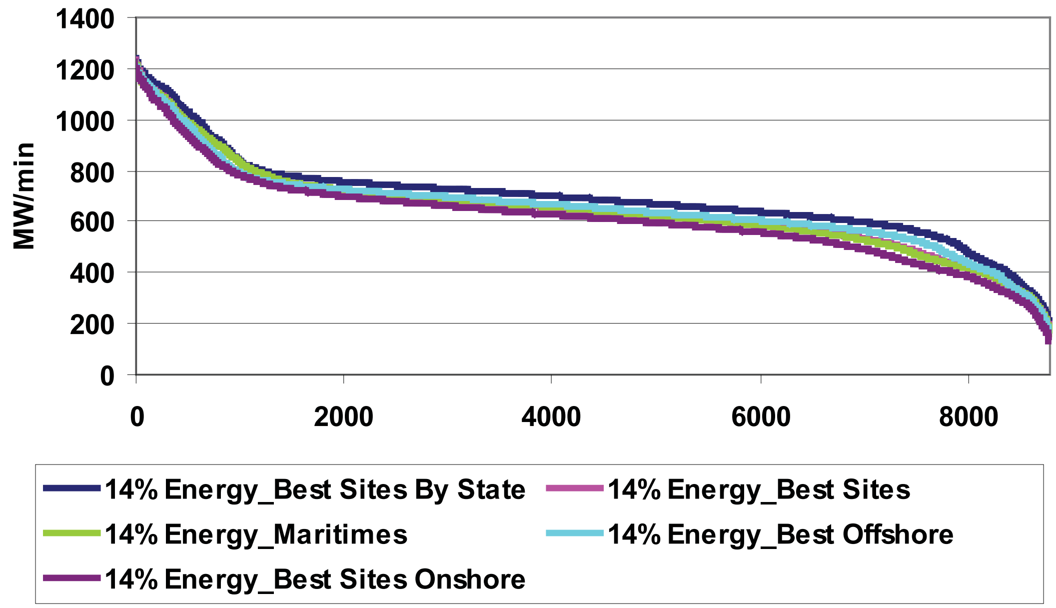


Figure B–22 Hourly ramp up MW/min capability, S-o-A forecast, 14% penetration

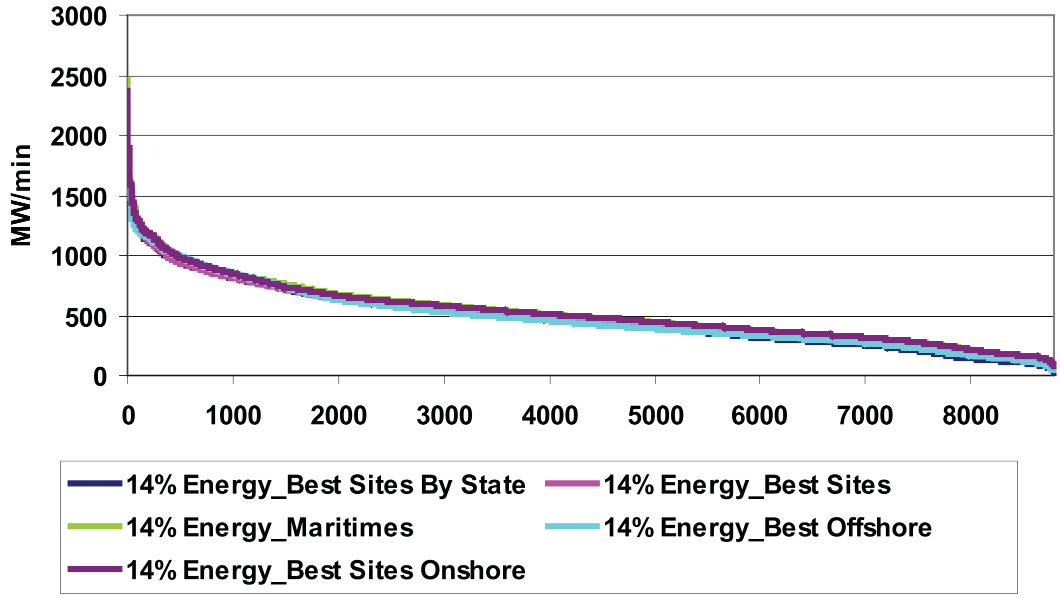
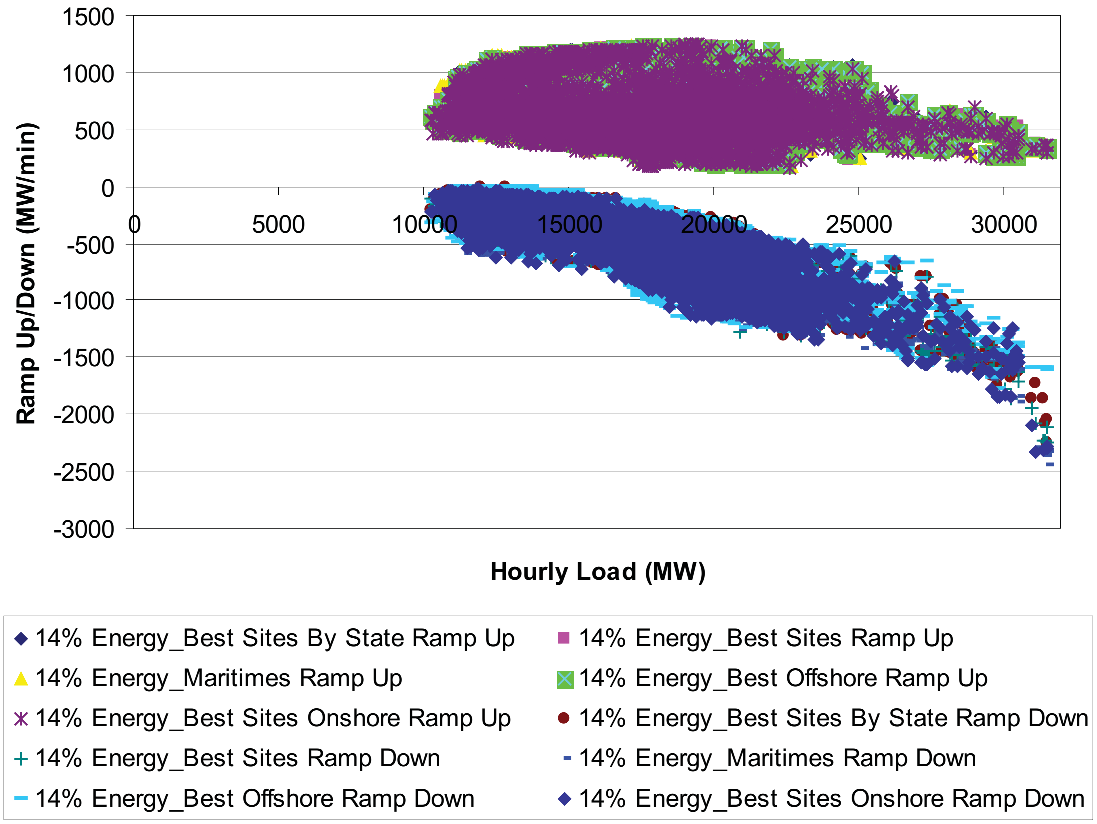


Figure B–23 Hourly ramp down MW/min capability, S-o-A forecast, 14% penetration



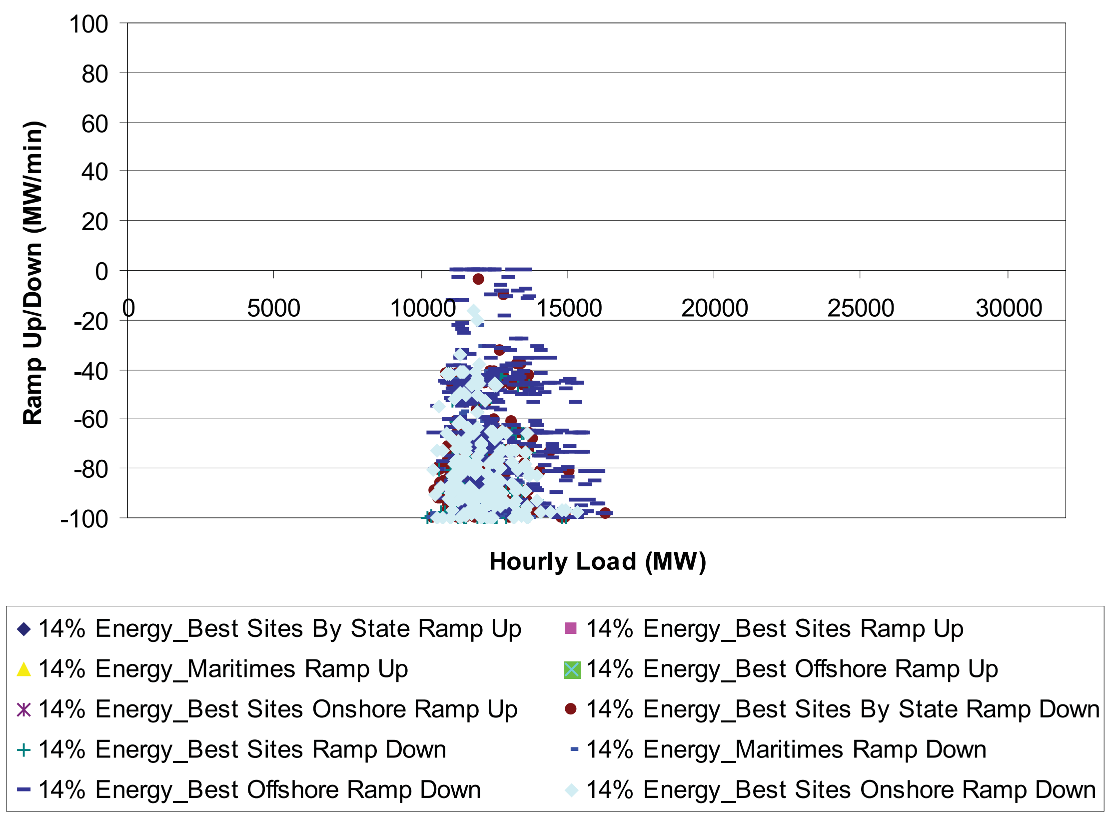


Figure B–24 Hourly Ramp Up/Down vs. Load, S-o-A forecast,14% Energy

Table B–3 Number of hours with ramp down capability < 100 MW/minute, 14% scenarios.

Scenario	# Hours
14% Energy_Best Sites By State	321
14% Energy_Best Sites	233
14% Energy_Best Sites Maritimes	136
14% Energy_Best Sites Offshore	301
14% Energy_Best Sites Onshore	185

Table B–4 ISO-NE Transmission Interface Summary, S-o-A forecast, 14% penetration

				14% Wind Penetration									
		2 GW		State		Offshore		Onshore		Sites		Maritimes	
Interface		Min Rating (MW)	Max Rating (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)
North-South	NP-2	-3800	3800	129	5211	124	5757	332	7126	99	5585	71	6714
Boston Import	NP-4	-4900	4900	669	4864	656	5602	660	5755	657	5547	657	4912
New England East-West	NP-5	-4300	4300	-2268	4350	-1658	5046	-1766	4395	-1806	4874	-1657	4827
Connecticut Export	NP-6	-4200	4200	-3179	1341	-3358	1163	-3697	1249	-3430	1264	-3541	1188
Connecticut Import	NP-7	-5300	5300	-767	3320	-657	3535	-668	3692	-668	3425	-668	3535
Southwestern Connecticut Import	NP-8	-3650	3650	230	2395	234	2392	196	2430	170	2393	239	2394
Norwalk-Stamford Import	NP-9	-1650	1650	422	1436	452	1435	386	1355	357	1412	191	1383
New York-New England	NP-10	-1600	1600	-1600	1600	-1600	1600	-1600	1600	-1600	1600	-1600	1600
Orrington South	NP-15	-2500	2500	-631	2912	-631	2866	-393	3321	-631	2889	-81	4799
Surowiec South	NP-16	-2100	2100	-1463	2304	-1449	3453	-1254	3747	-1336	3135	-400	3889
Maine-New Hampshire	NP-17	-2700	2700	-1596	3067	-1581	4415	-1049	5778	-1426	4170	-487	5114
SEMA Export	NP-19	-9999	9999	-1138	1165	-1105	2549	-1408	975	-1178	1625	-1413	994
West - East	NP-20	-4400	4400	-2945	2268	-3566	1797	-3405	1854	-3405	1688	-3484	1680
NB - NE	NP-21	-500	1000	-1027	1048	-1000	1000	-1000	1000	-1023	1108	-715	2890
SEMA/RI Export	NP-22	-4200	4200	-1246	3050	-1094	4510	-1312	2811	-1365	3618	-1713	2749

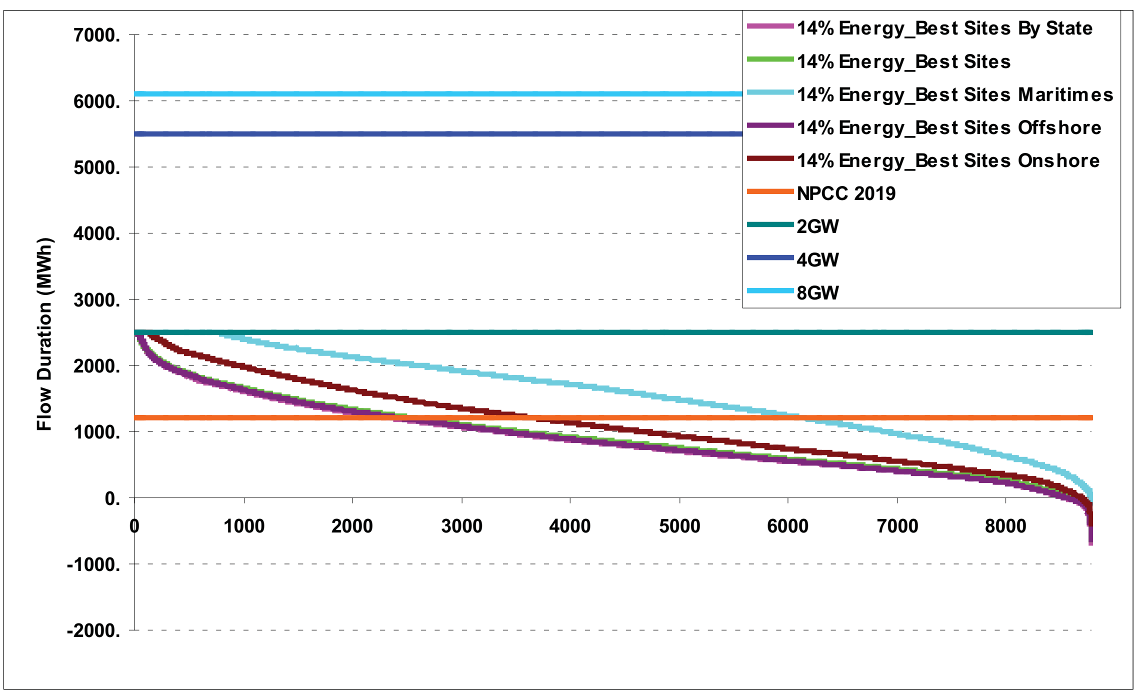


Figure B–25 Orrington South interface flow, S-o-A forecast, 14% penetration

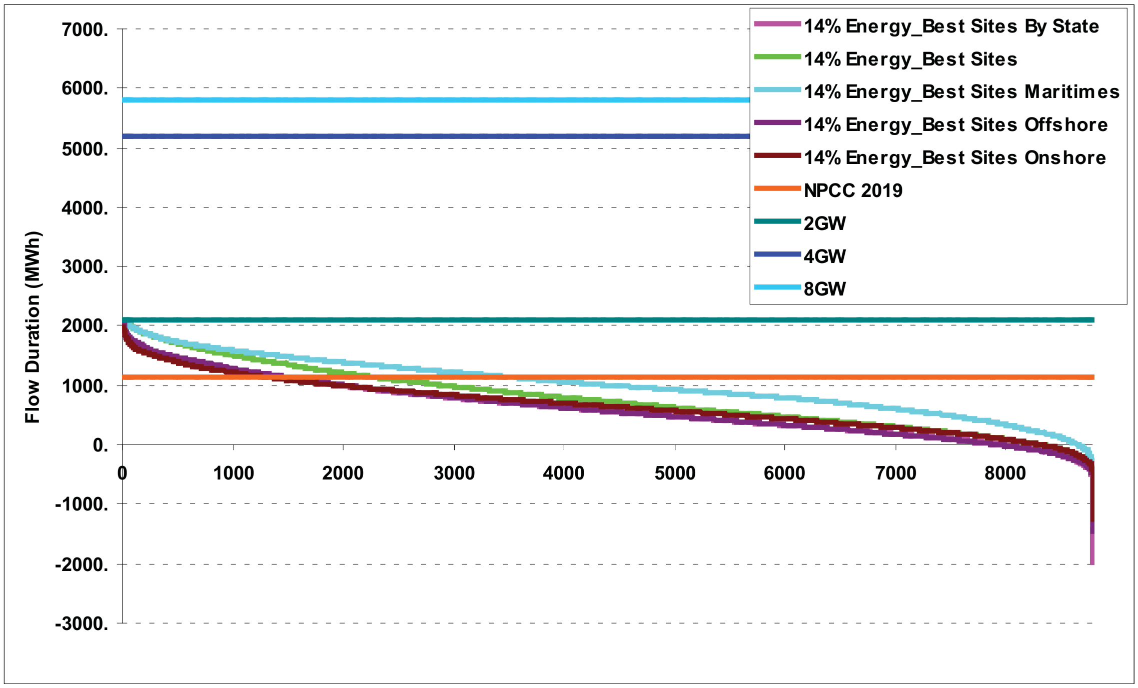


Figure B–26 Surowiec South interface flow, S-o-A forecast, 14% penetration

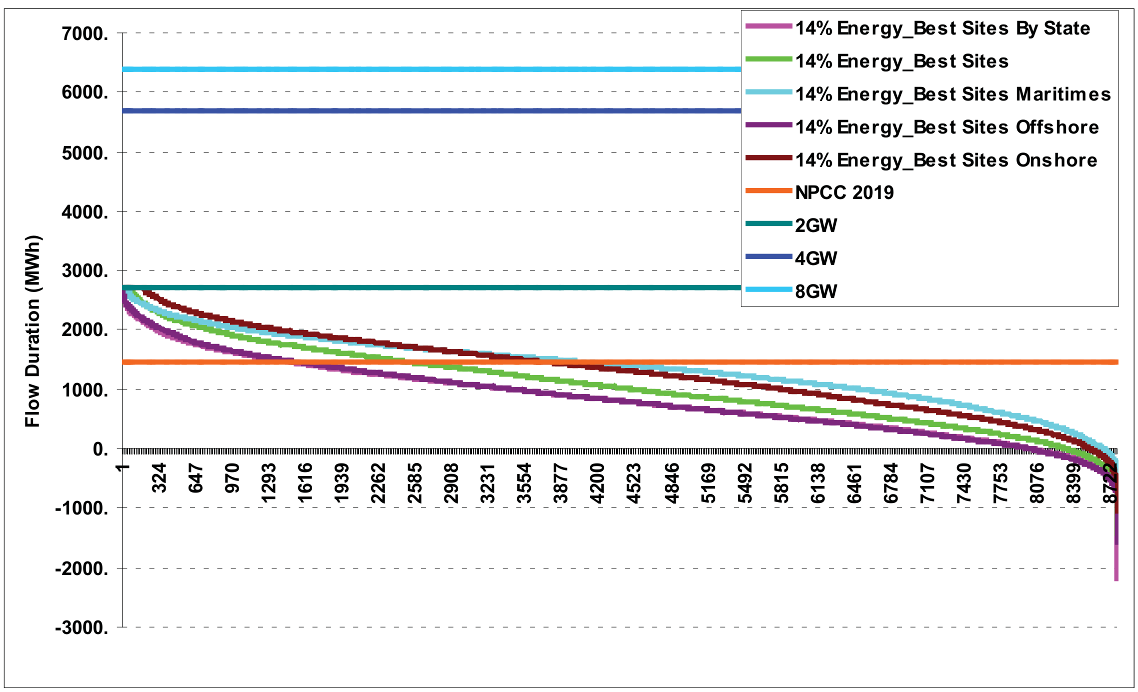


Figure B–27 Maine/New Hampshire interface flow, S-o-A forecast, 14% penetration

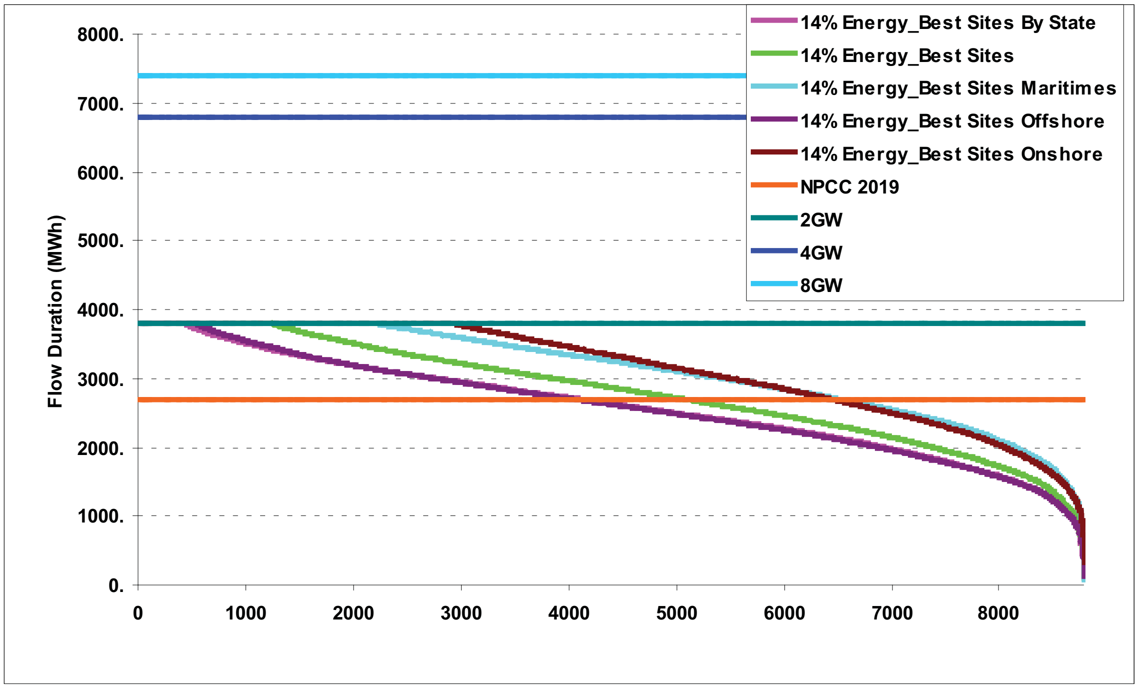


Figure B–28 North /South interface flow, S-o-A forecast, 14% penetration

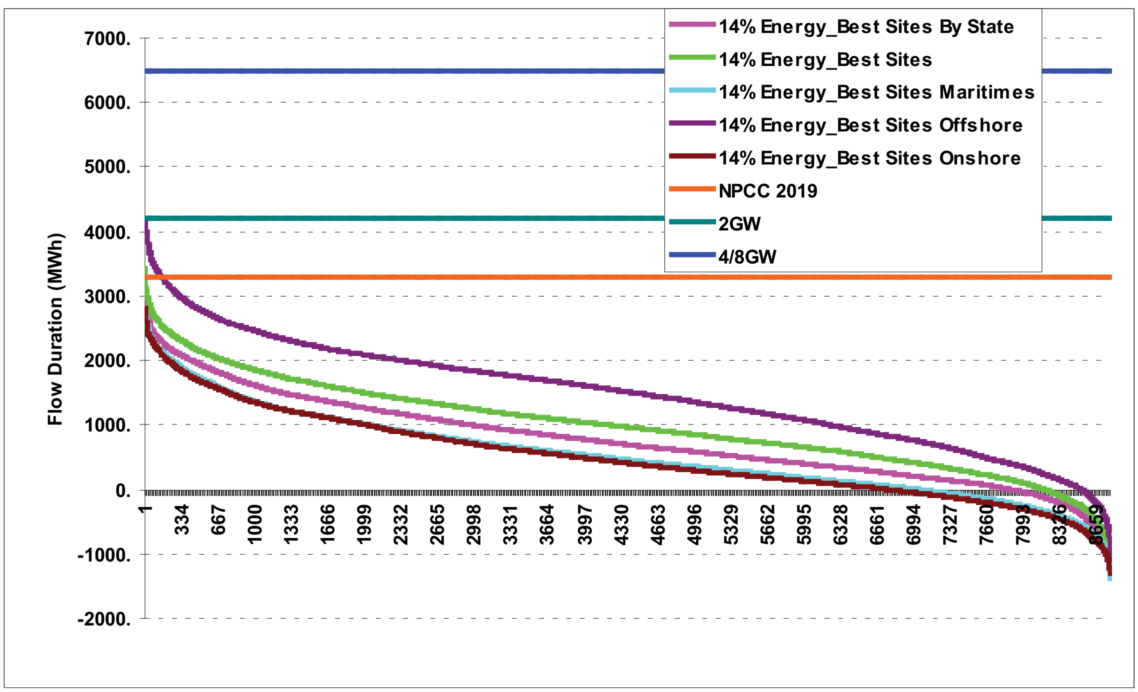


Figure B–29 SEMA/RI Export interface flow, S-o-A forecast, 14% penetration

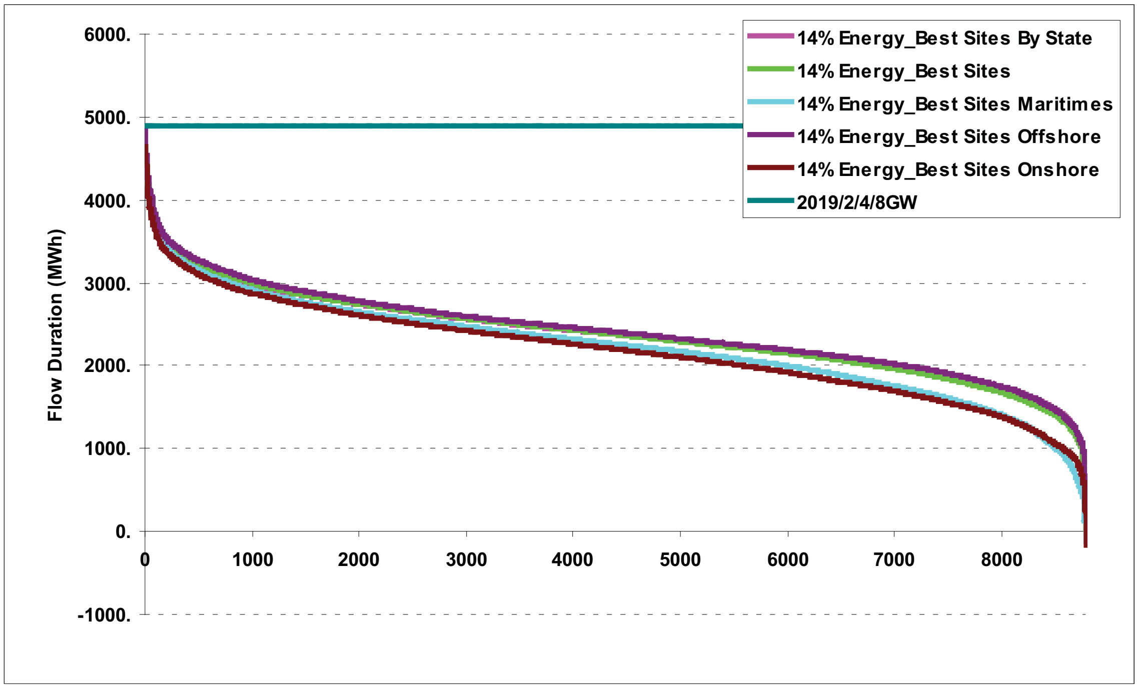


Figure B–30 Boston Import, S-o-A forecast interface flow, 14% penetration

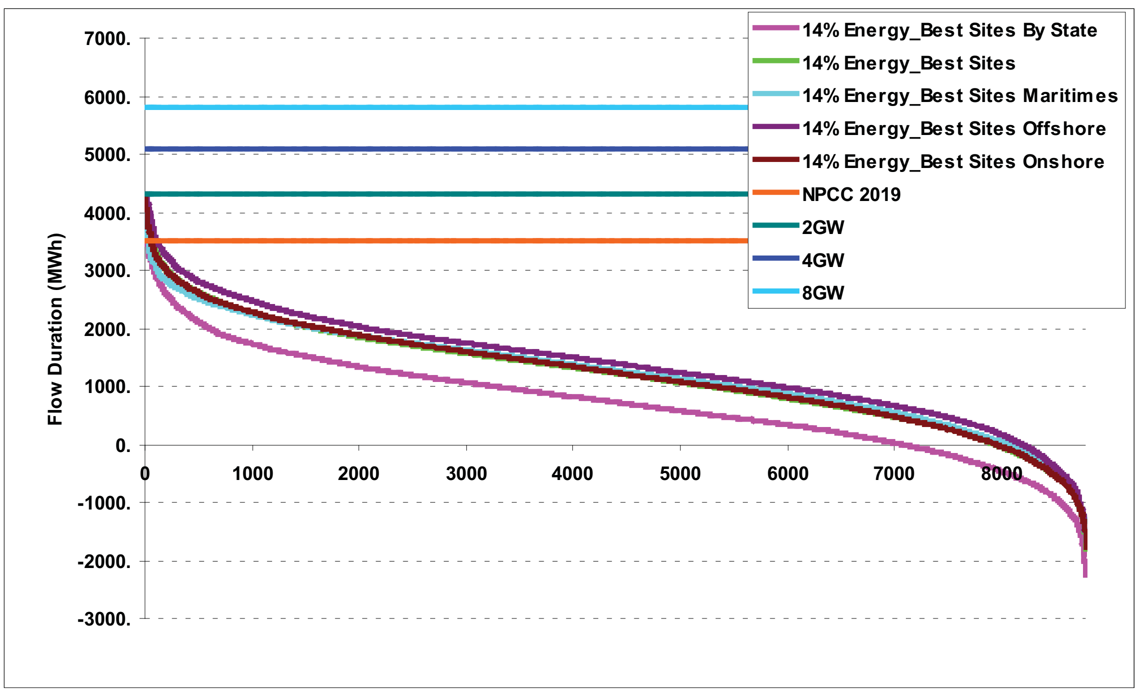


Figure B–31 East-West interface flow, S-o-A forecast, 14% penetration

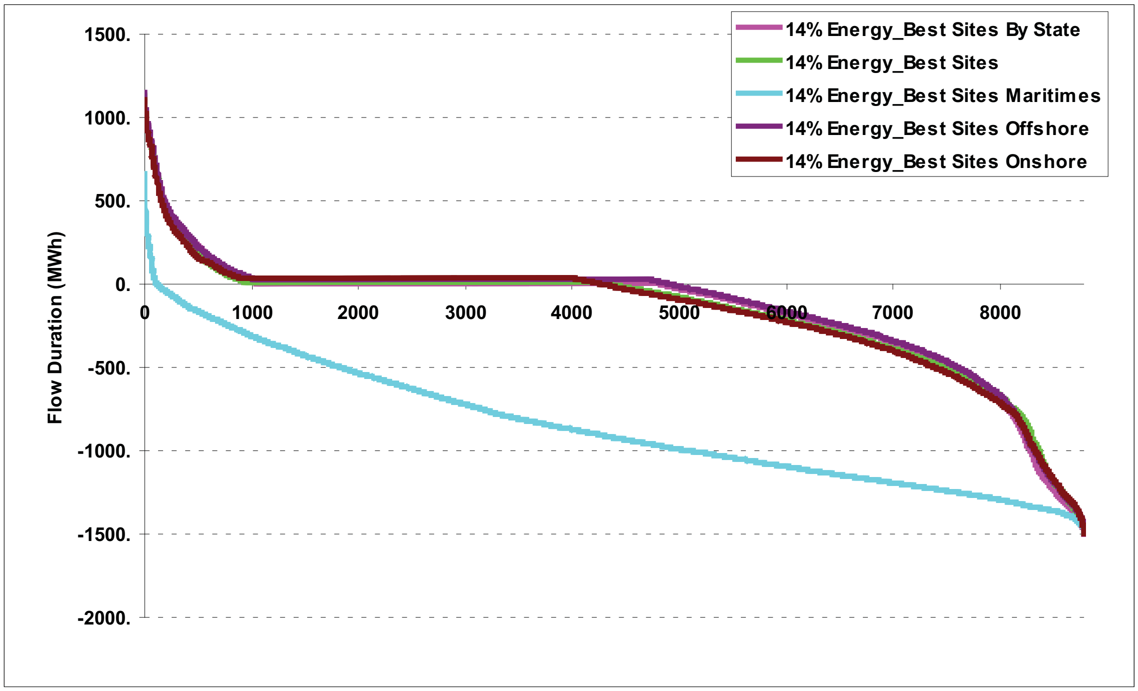


Figure B–32 ISO-NE to NB interface flow, S-o-A forecast, 14% penetration

B.2 Best Sites Offshore

The following section compares the impact of increasing penetration for the Best Sites Offshore scenario. The results were done using 2006 load and wind shapes, an unbiased State-of-the-Art (S-o-A) day ahead forecast of the wind generation and a constrained transmission system.

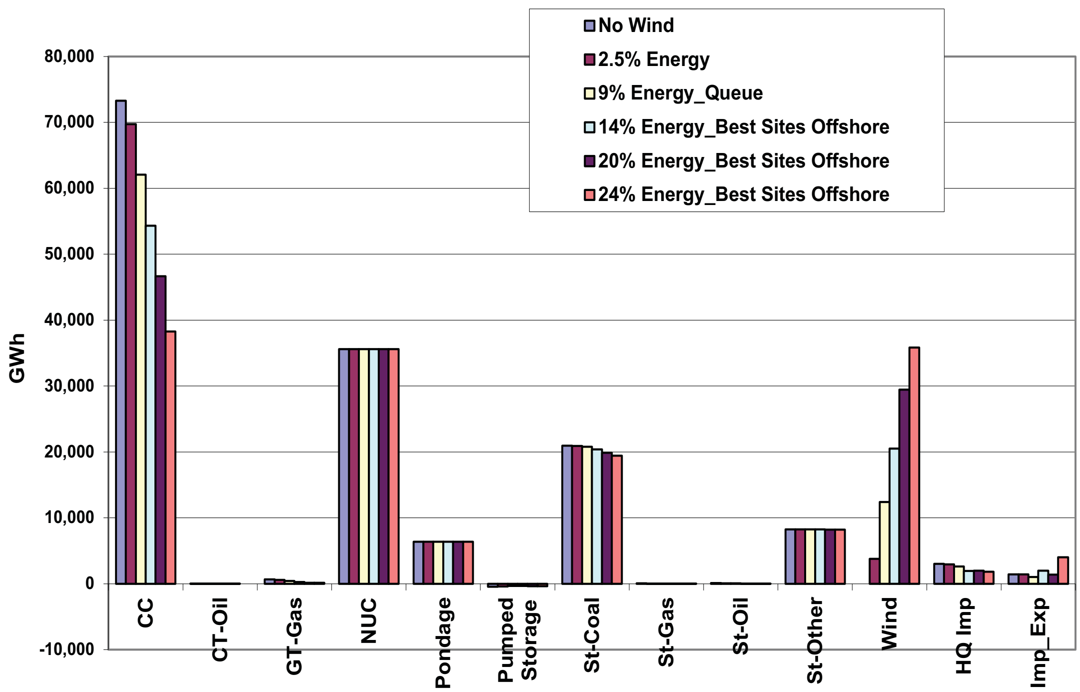


Figure B–33 ISO-NE generation by type, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

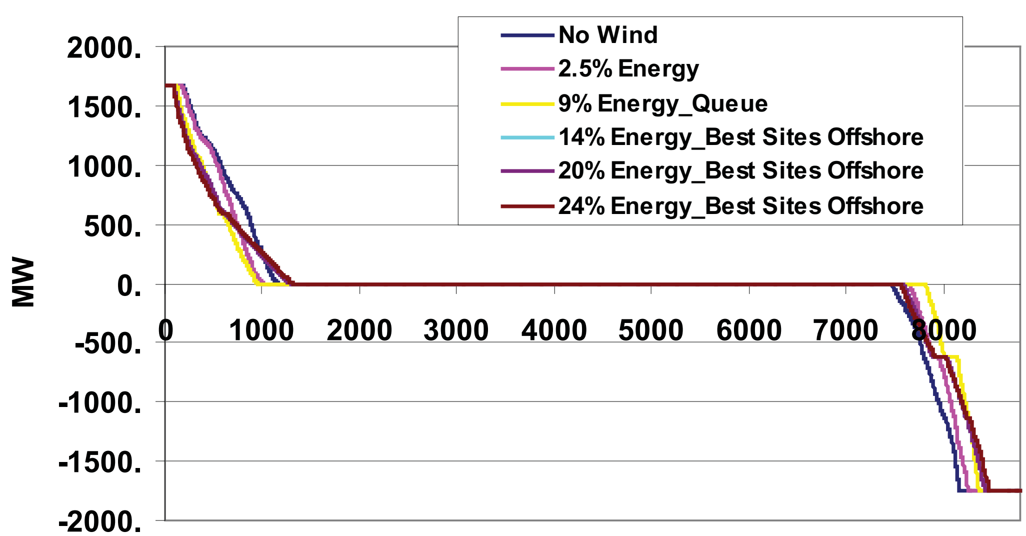


Figure B–34 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

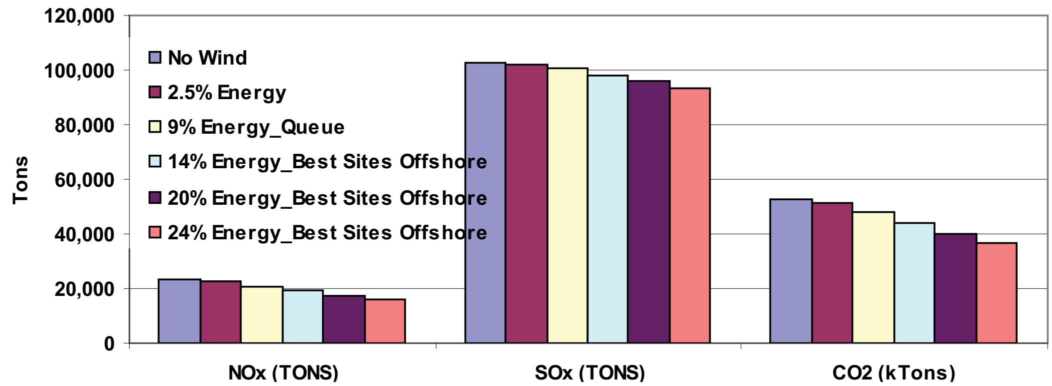


Figure B–35 ISO-NE Total Emissions, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

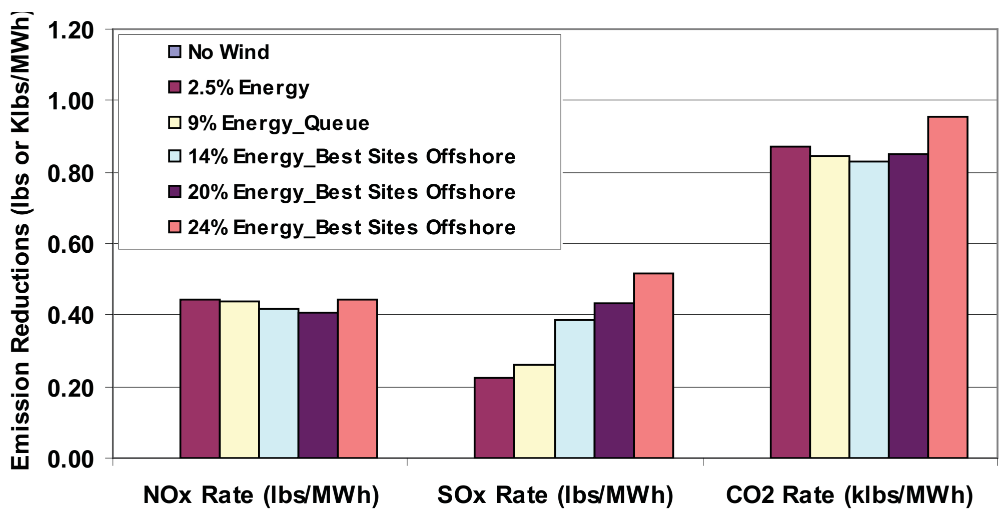


Figure B–36 ISO-NE total emission reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

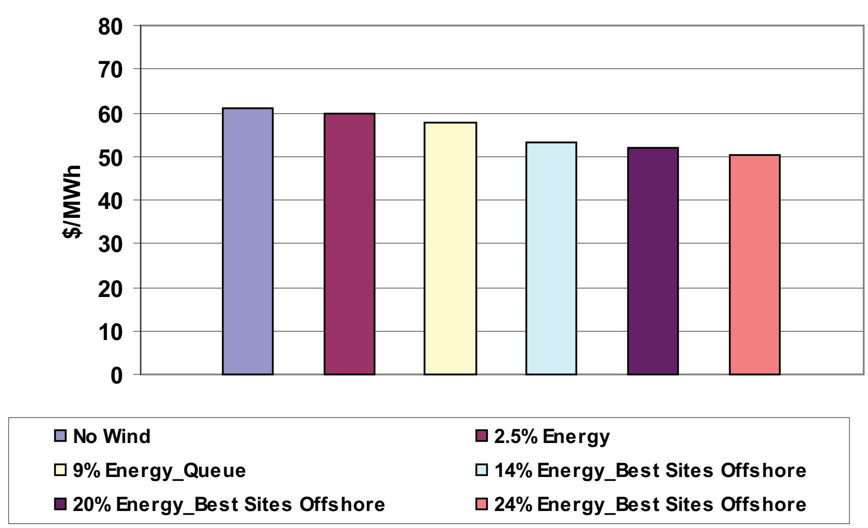


Figure B–37 Annual load weighted average ISO-NE location market price, S-O-A Forecast, Best Sites Offshore, S-o-A Forecast

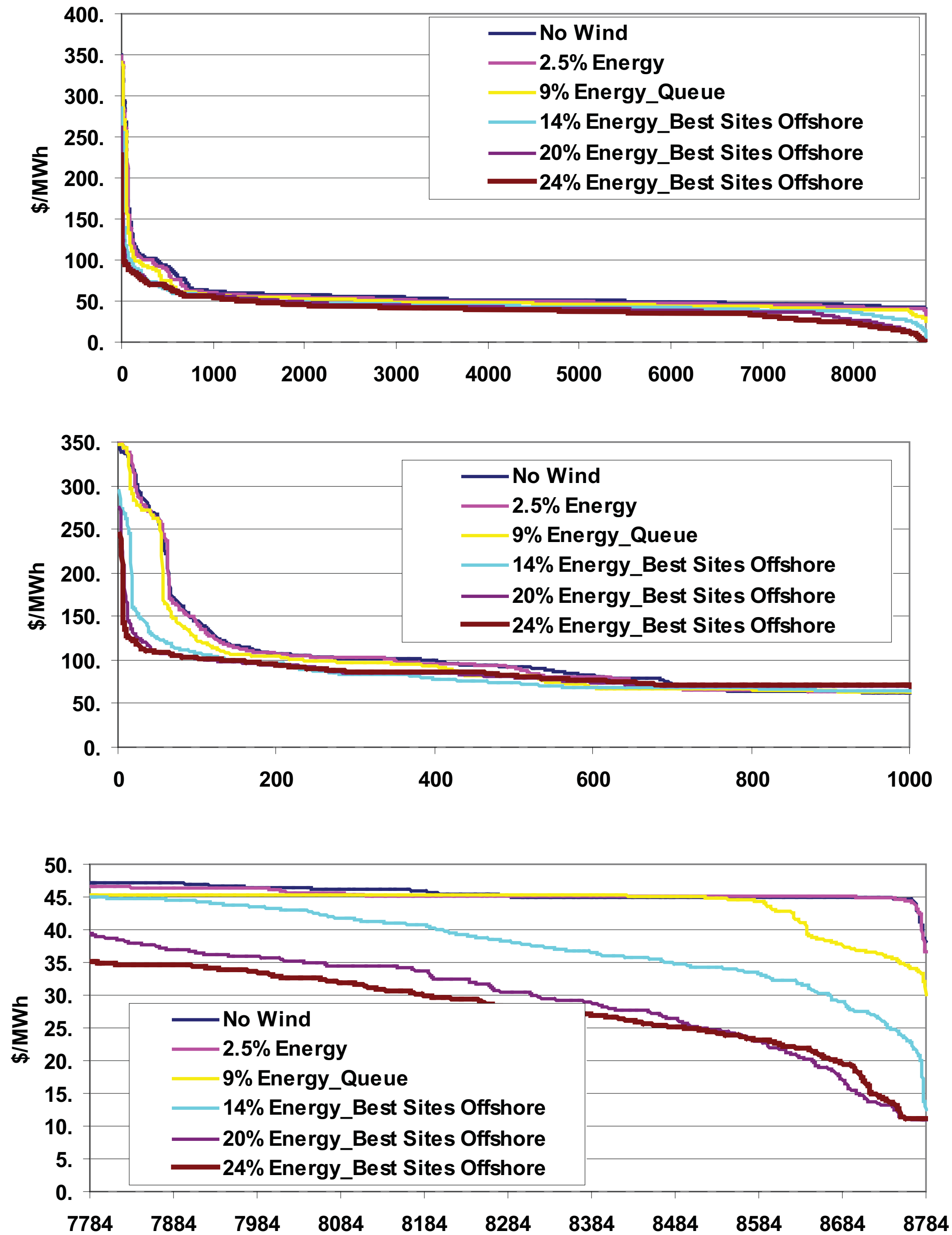


Figure B–38 Annual LMP duration curve, S-O-A Forecast, Best Sites Offshore, S-o-A Forecast

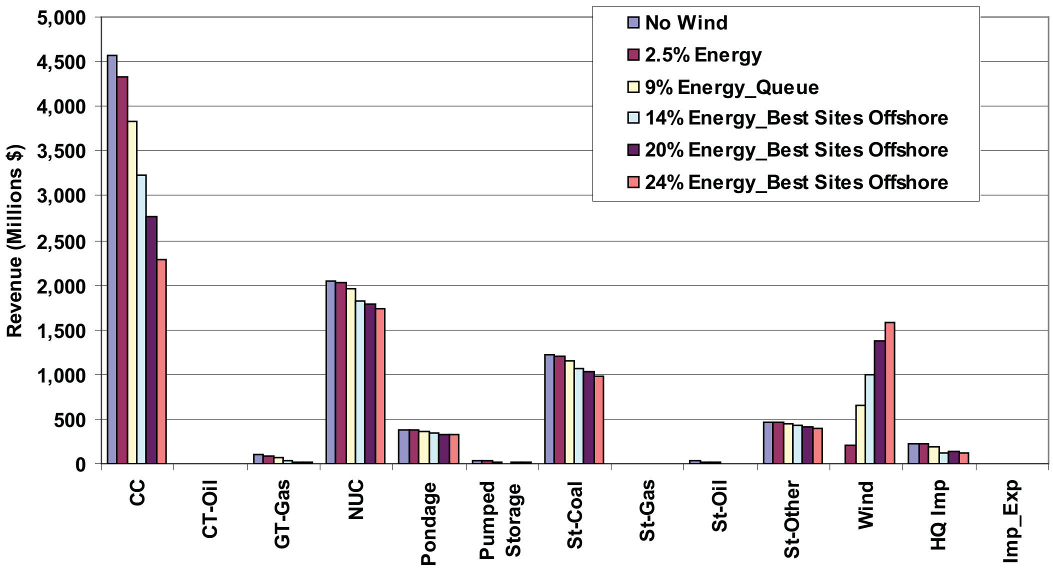


Figure B–39 ISO-NE revenue by type, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

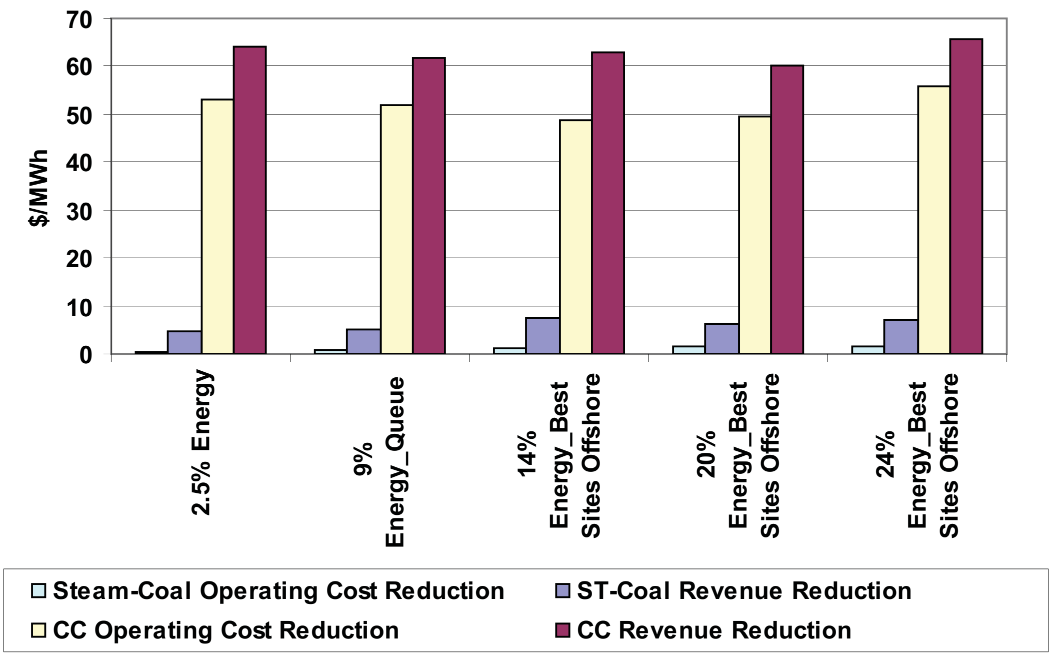


Figure B–40 ISO-NE CC and St-coal revenue and operating cost reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

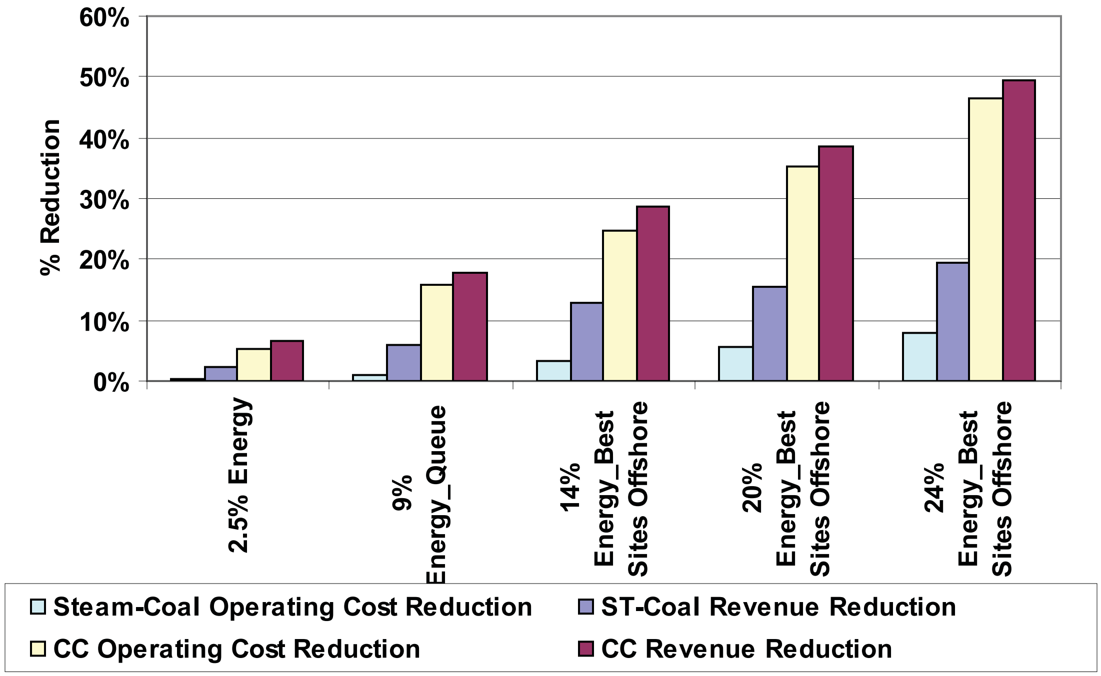


Figure B–41 ISO-NE CC and St-coal revenue and operating cost percent reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

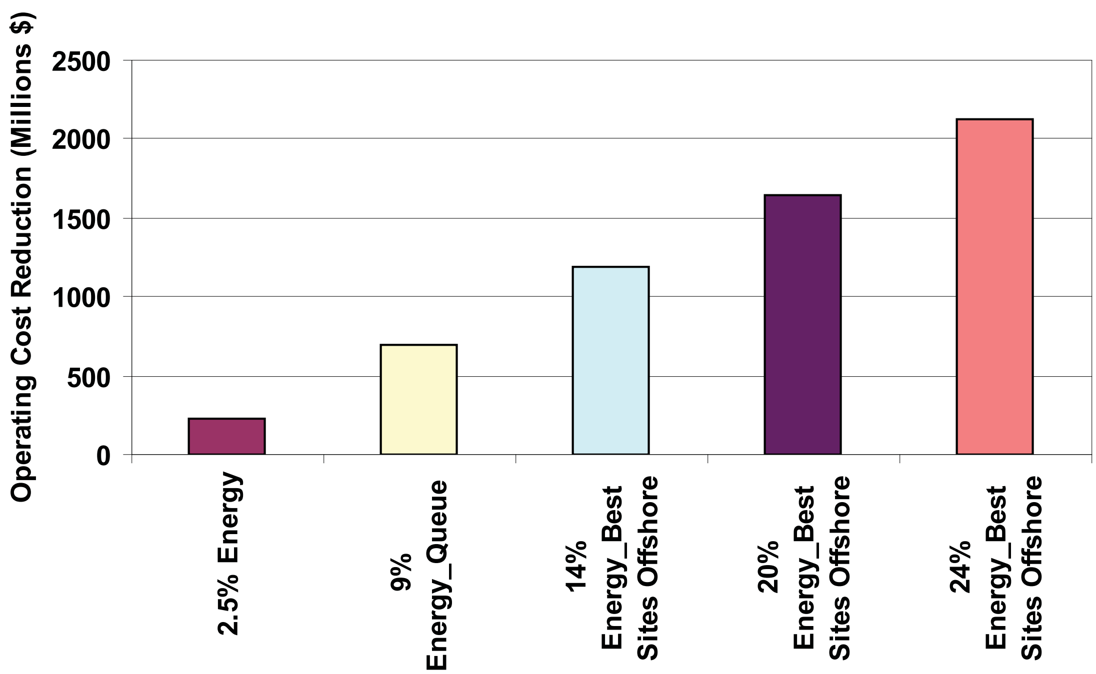


Figure B–42 ISO-NE operating Cost reduction, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

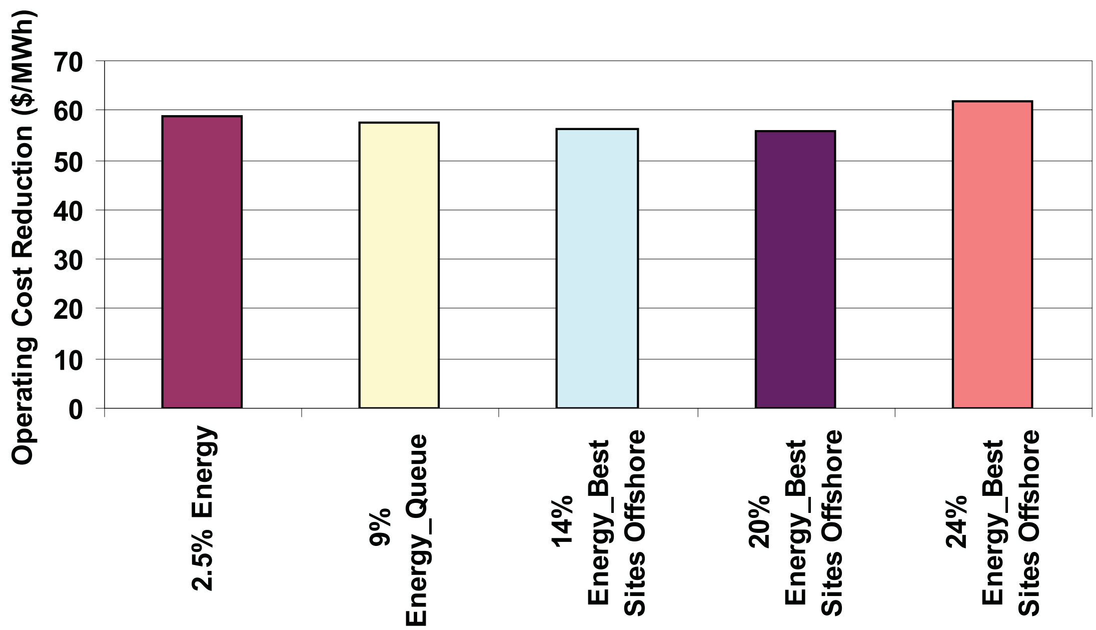


Figure B–43 ISO-NE operating cost reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

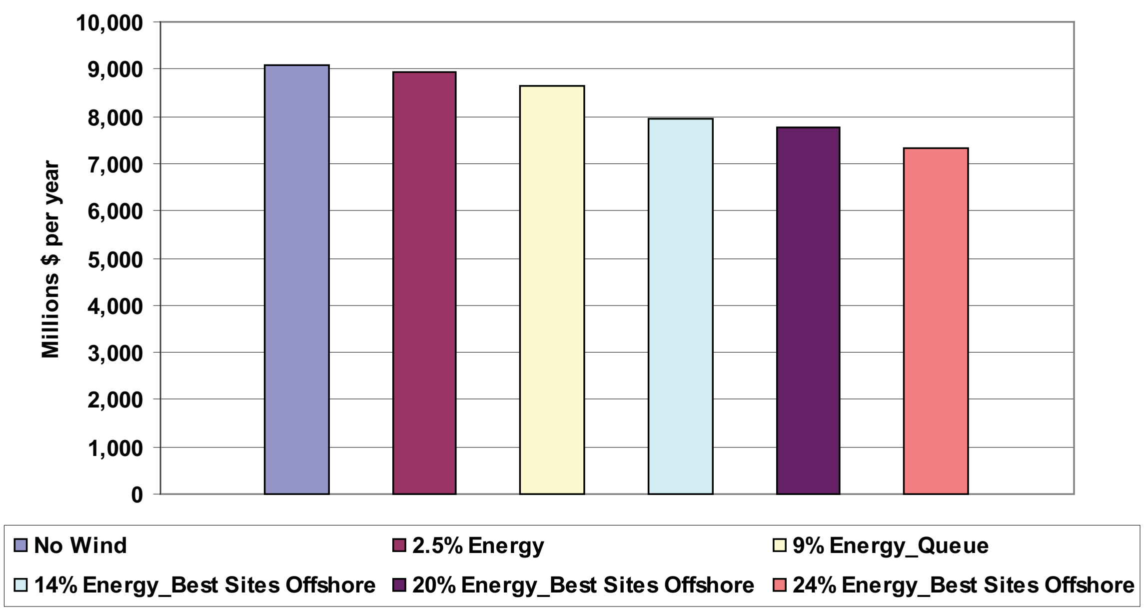


Figure B–44 ISO-NE wholesale load payments for energy, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

Table B–5 ISO-NE Copper Sheet Transmission Interface Summary, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

	No Wind		2.5%		9%		14%		20%		24%	
Interface	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)
North-South	196	4904	-46	3987	20	5605	124	5757	-821	5193	-986	4670
Boston Import	526	4615	549	4464	633	5328	656	5602	656	5019	91	3970
New England East-West	-1451	2720	-1213	3760	-784	4214	-1658	5046	-1743	5883	-1902	6276
Connecticut Export	-2652	1464	-2723	1379	-3031	1175	-3358	1163	-3737	1259	-3333	1485
Connecticut Import	-867	2986	-669	3001	-608	3331	-657	3535	-663	3754	-858	3436
Southwestern Connecticut Import	176	2151	184	2157	252	2363	234	2392	68	2554	87	2695
Norwalk-Stamford Import	470	1255	438	1255	430	1279	452	1435	109	1476	266	1481
New York-New England	-1525	1600	-1525	1582	-1525	1525	-1600	1600	-1600	1600	-1600	1600
Orrington South	-304	1804	-211	1897	-518	2390	-631	2866	-467	3145	-508	3354
Surowiec South	-672	1761	-587	1988	-1435	3104	-1449	3453	-625	3272	-702	3350
Maine-New Hampshire	-952	2583	-897	2559	-1589	4687	-1581	4415	-1005	3374	-1008	3479
SEMA Export	-1622	785	-1422	1131	-1035	2750	-1105	2549	-1025	4696	-1518	5432
West - East	-2227	2192	-3267	1501	-3074	1129	-3566	1797	-5297	1739	-5800	1897
NB - NE	-500	1000	-500	1000	-1000	1000	-1000	1000	-500	1000	-500	1000
SEMA/RI Export	-591	3369	-406	3502	-691	4476	-1094	4510	-974	5940	-1335	6861

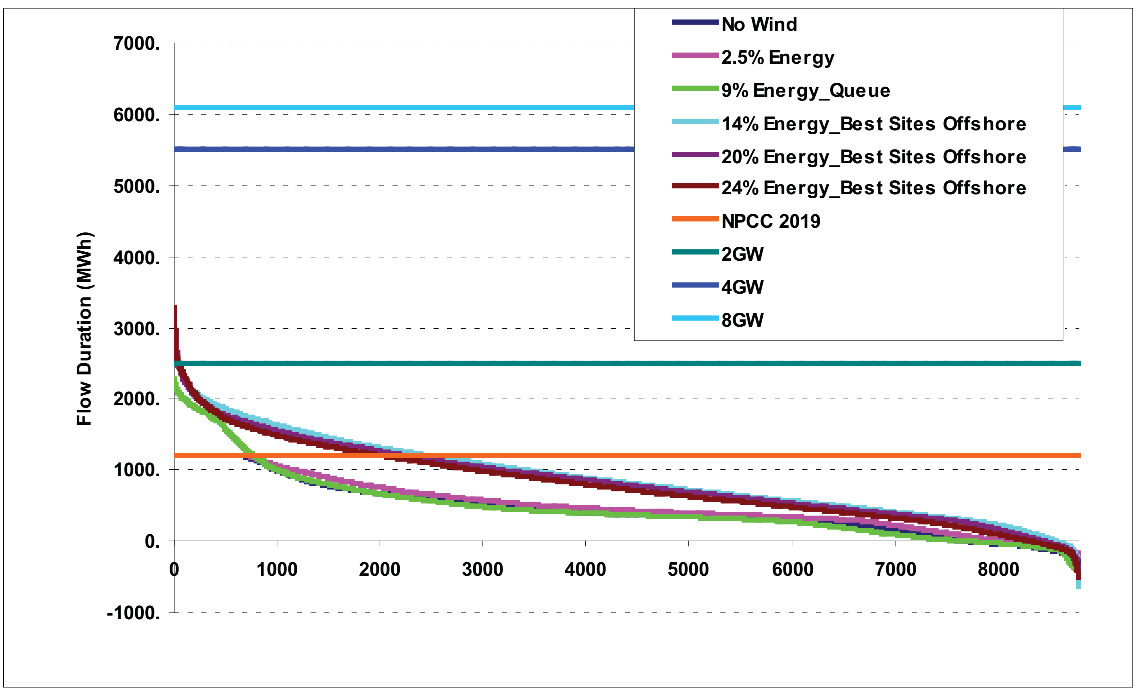


Figure B–45 Orrington South interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

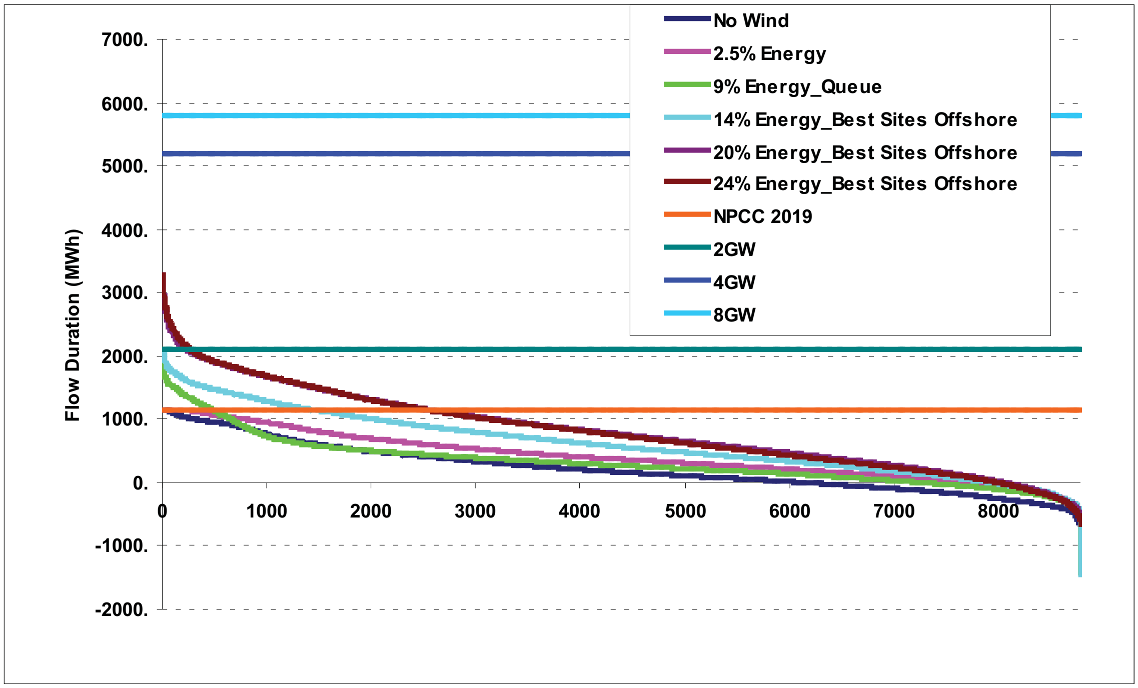


Figure B–46 Surowiec South interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

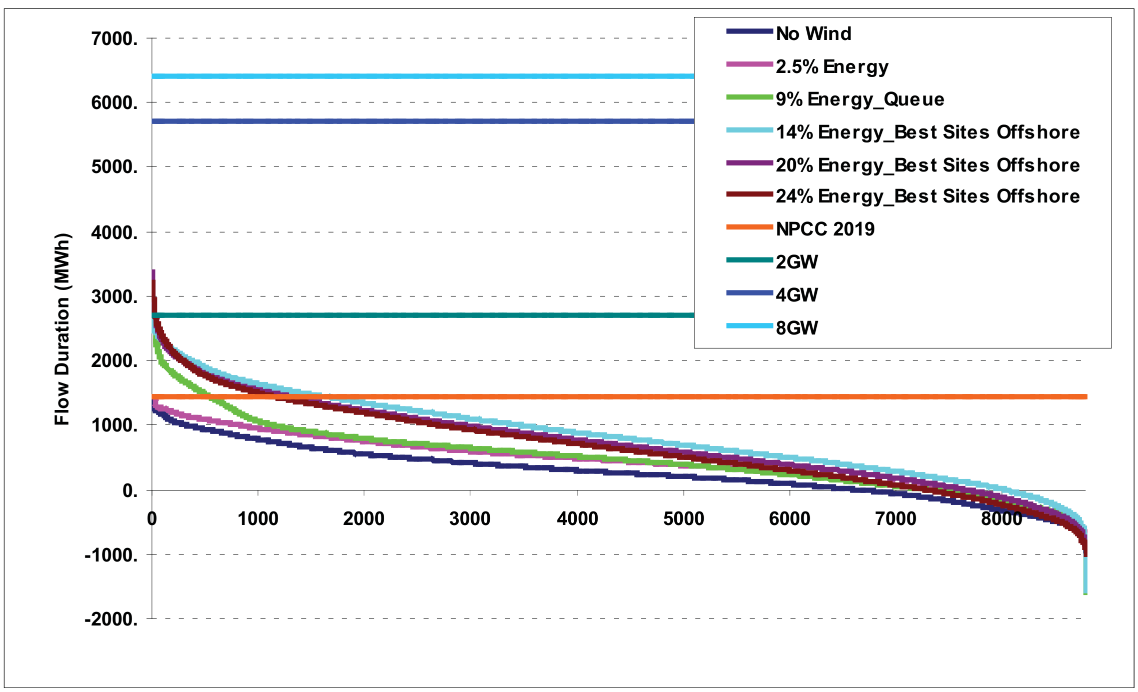


Figure B–47 Maine/New Hampshire interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

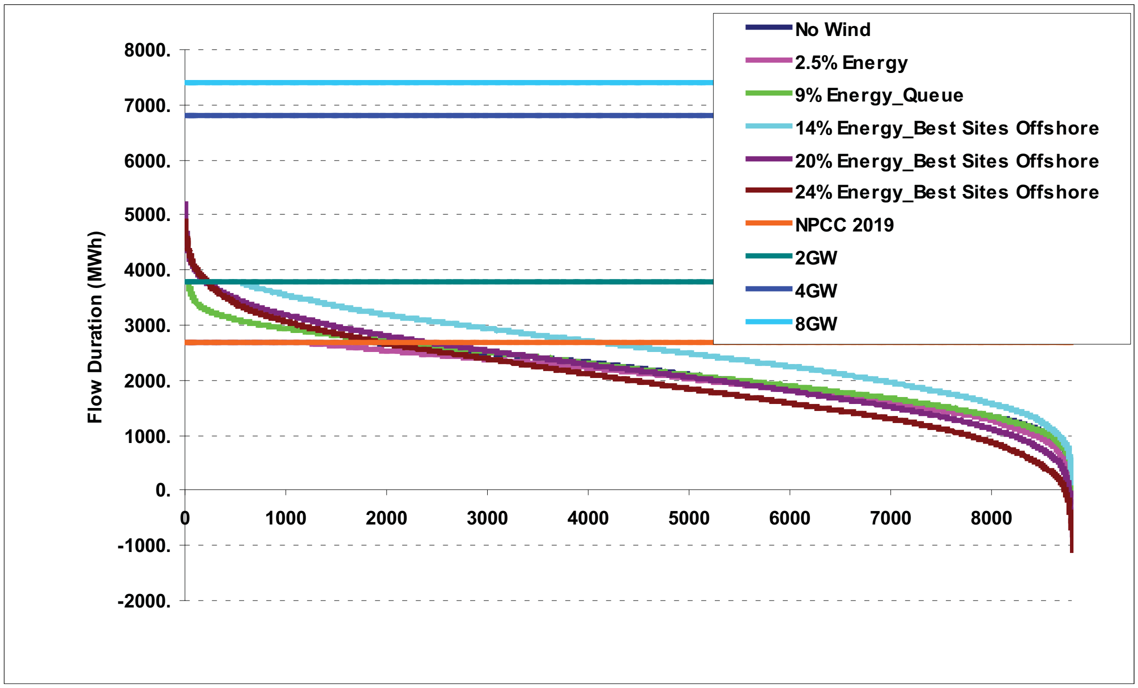


Figure B–48 North /South interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

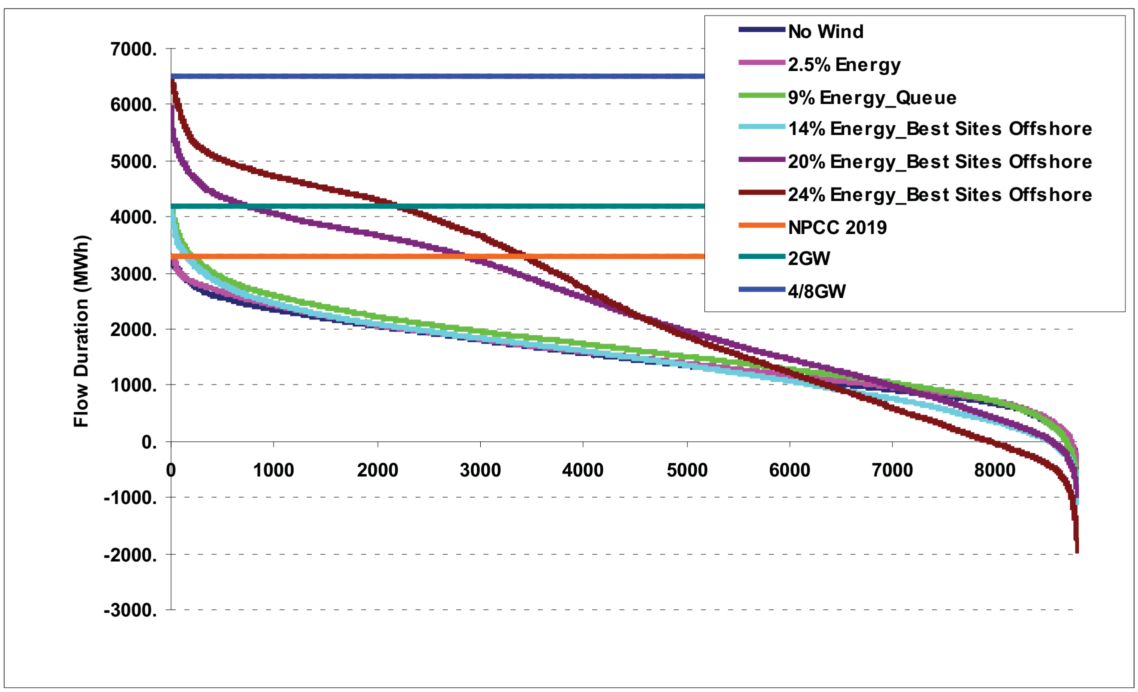


Figure B–49 SEMA/RI Export interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

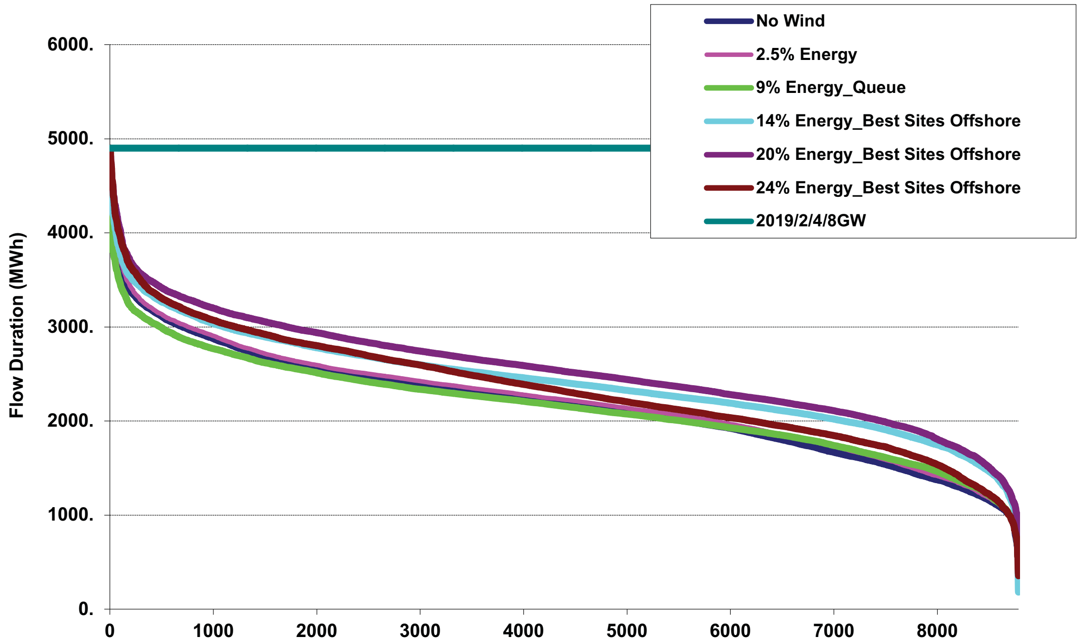


Figure B–50 Boston Import, S-o-A forecast interface flow, Best Sites Offshore, S-o-A Forecast

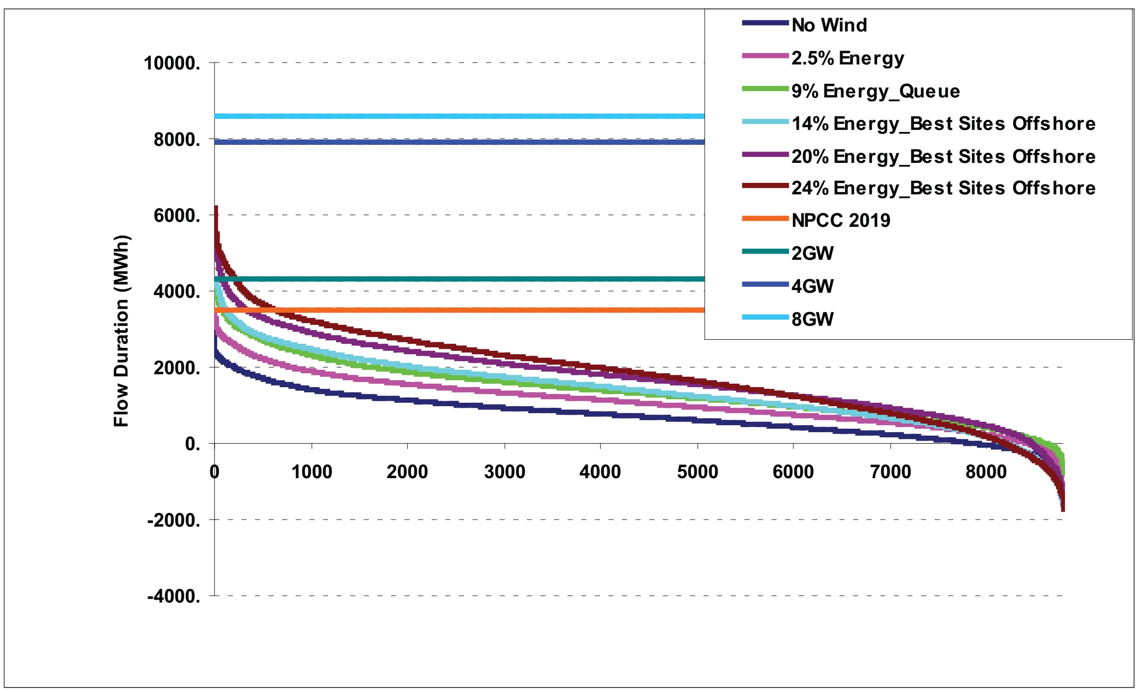


Figure B–51 East-West interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

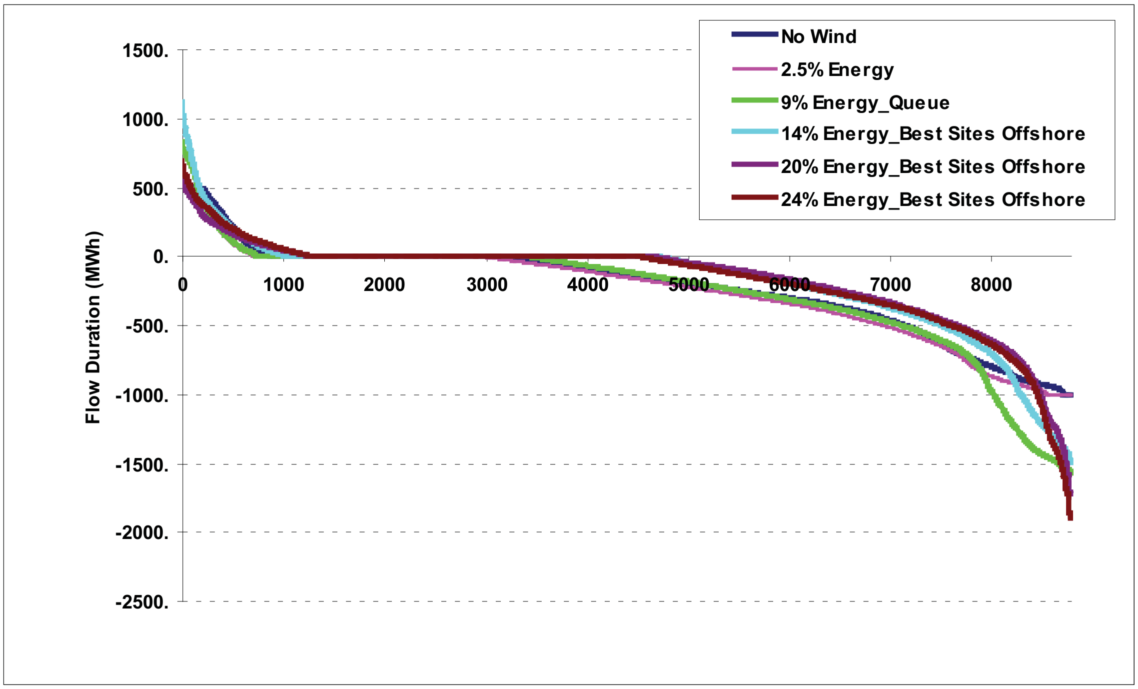


Figure B–52 ISO-NE to NB interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

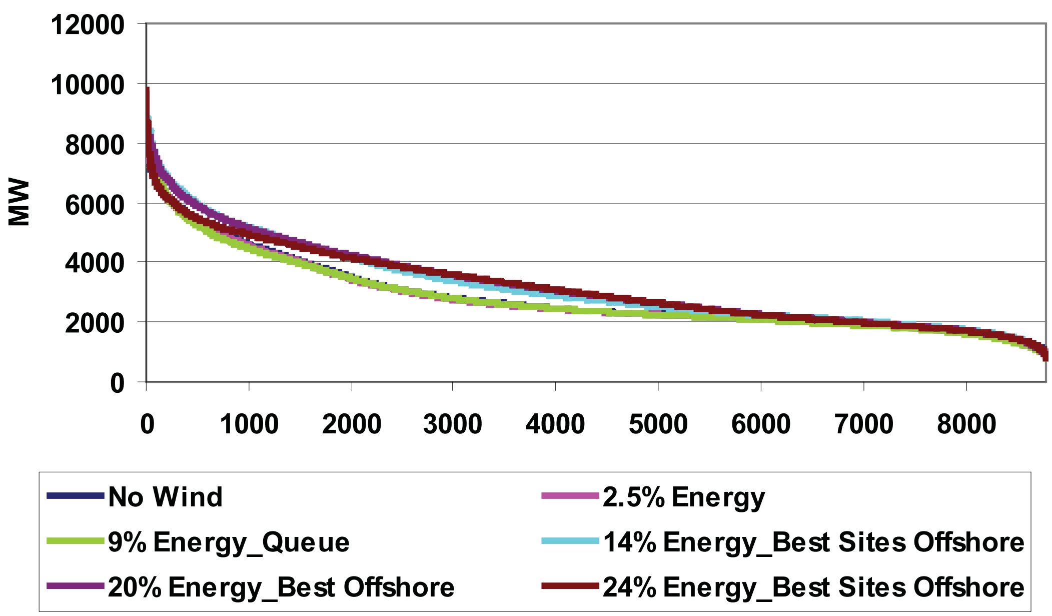


Figure B–53 Hourly Range Up Capability, Best Sites Offshore, S-o-A Forecast

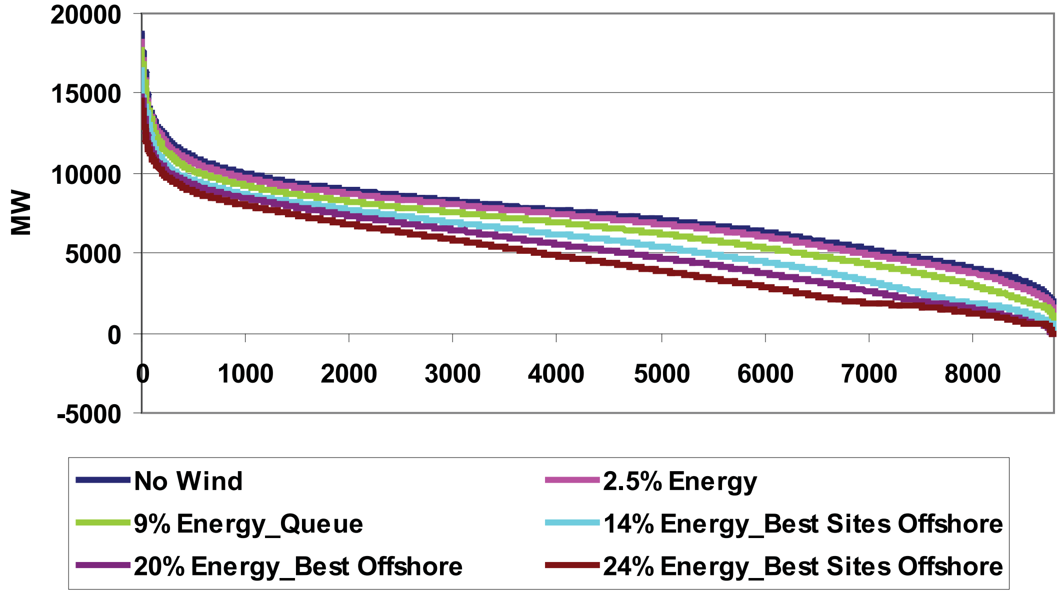


Figure B–54 Hourly Range Down Capability, Best Sites Offshore, S-o-A Forecast

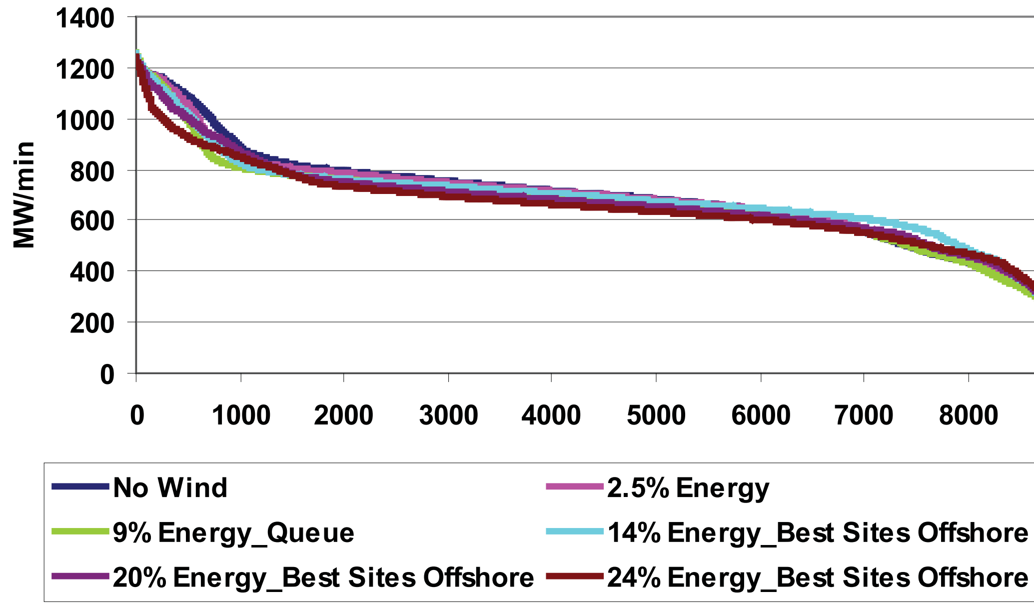


Figure B–55 Hourly Ramp Up Capability, Best Sites Offshore, S-o-A Forecast, S-o-A Forecast

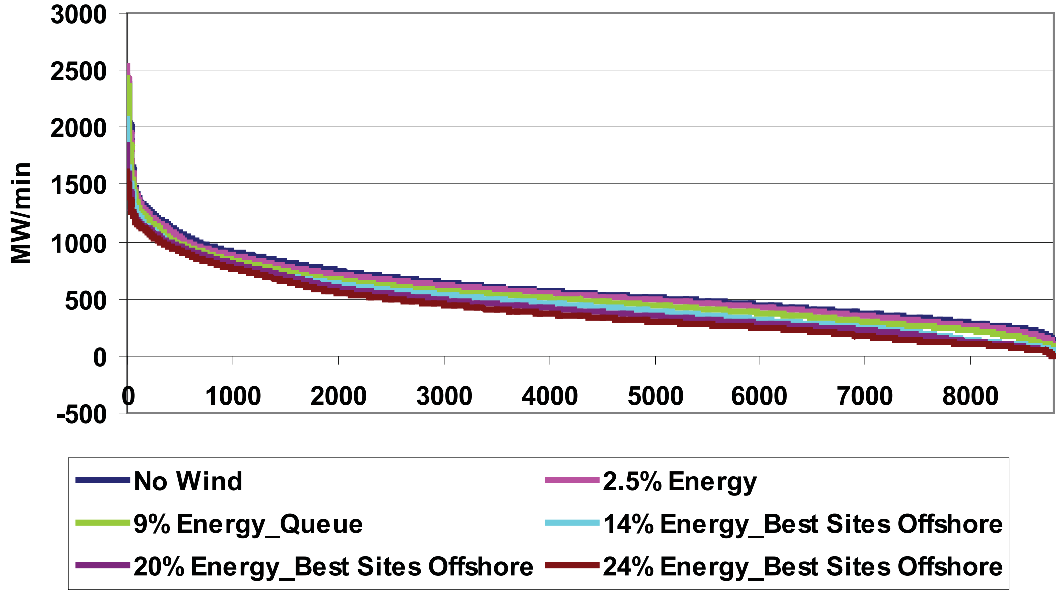
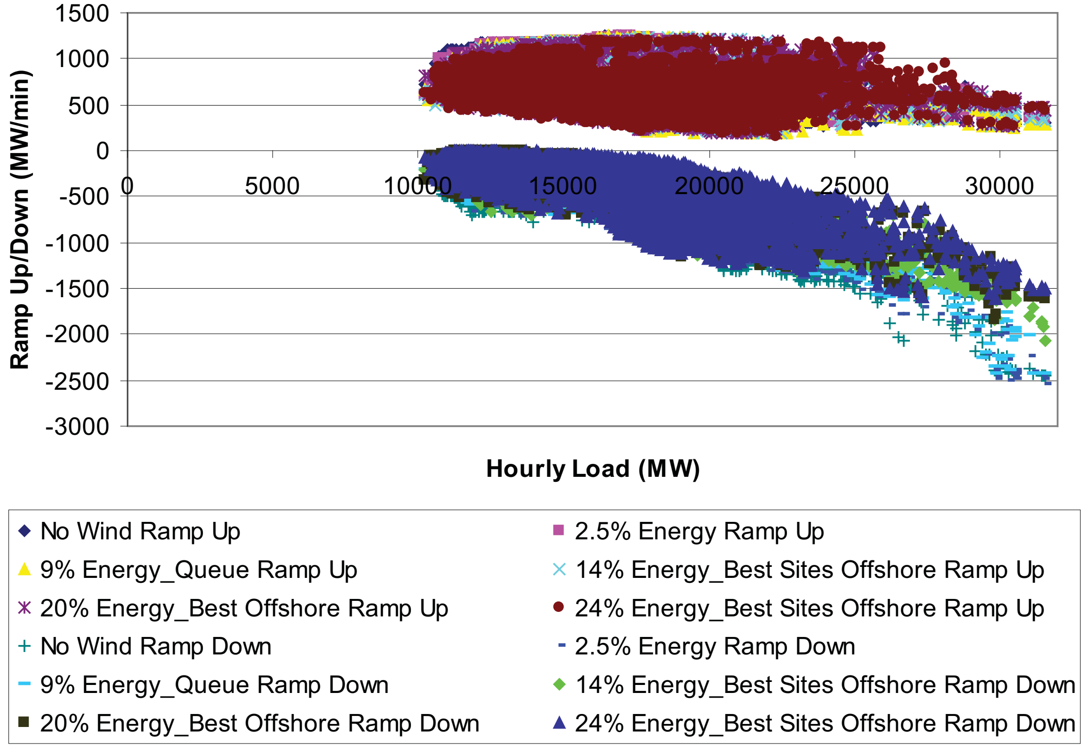


Figure B–56 Hourly Ramp Down Capability, Best Sites Offshore, S-o-A Forecast



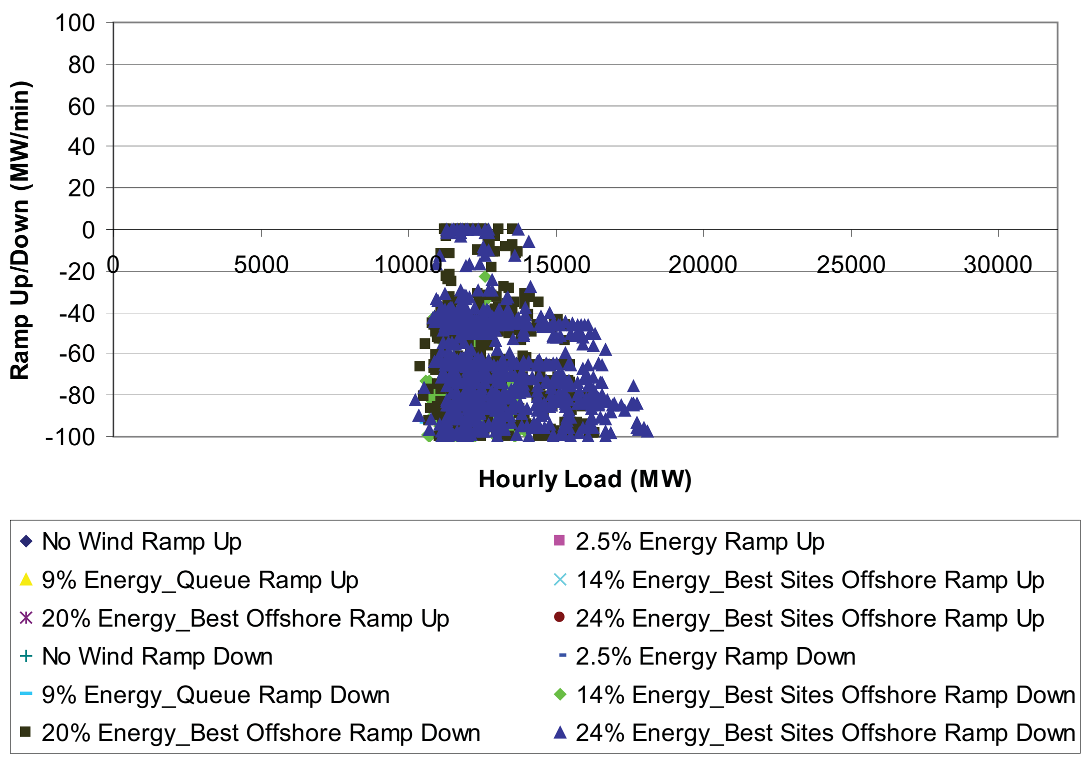


Figure B–57 Hourly Ramp Up/Down CapabilityMW/min vs. Load, S-o-A forecast, Best Sites Offshore

Table B–6 Number of hours with ramp down capability < 100 MW/minute.

Scenario	#
No Wind	0
2.5% Energy	3
9% Energy_Queue	43
14% Energy_Best Sites Offshore	301
20% Energy_Best Sites Offshore	451
24% Energy_Best Sites Offshore	662

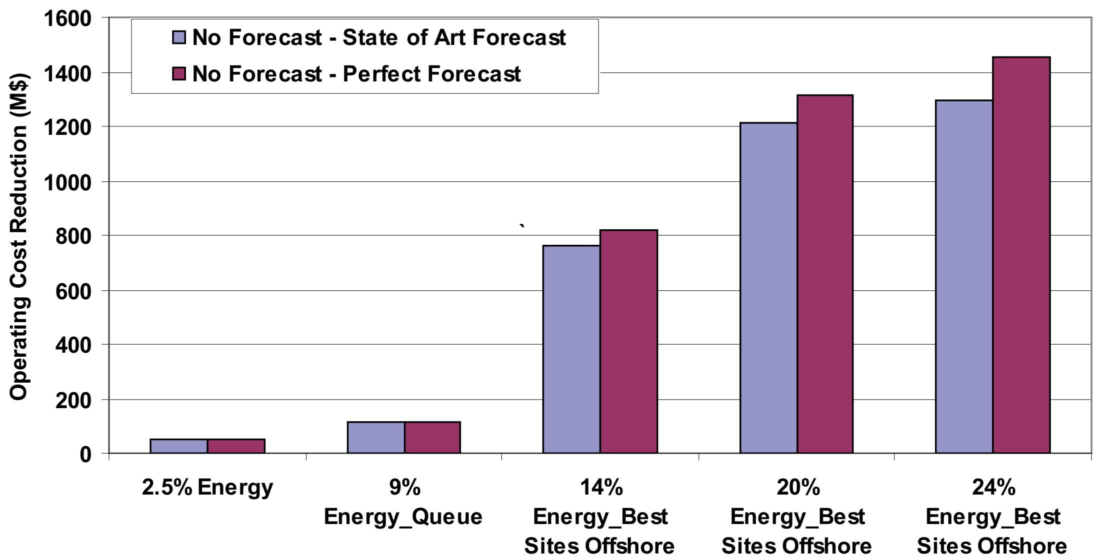


Figure B–58 System operating cost impacts of forecast (M$), Best Sites Offshore

Appendix C – MAPS Description

GE Energy

MAPS™

(Multi-Area Production Simulation Software)

Program Description

Multi-Area Production Simulation software (MAPS™) is owned and supported by GE Energy. All inquiries regarding MAPS should be directed to:

Devin T. Van Zandt
Manager-Software Products
GE Energy
1 River Road
Schenectady, NY 12345
518-385-9066
devin.vanzandt@ge.com

MAPS is available for installation on a compatible in-house computer system through a software licensing agreement with GE Energy. The program can also be accessed through contract studies performed by GE Energy's Energy Applications and Systems Engineering group.

Table of Contents

Multi-Area Production Simulation Software (MAPS™)

1. MAPS – Unique Capabilities

MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. When the program was initially developed over twenty years ago, its primary use was as a generation and transmission planning tool to evaluate the impacts of transmission system constraints on the system production cost. In the current deregulated utility environment, the acronym MAPS may more also stand for Market Assessment & Portfolio Strategies because of the model's usefulness in studying issues such as market power and the valuation of generating assets operating in a competitive environment.

The unique modeling capabilities of MAPS use a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints.

Separate dispatches of the interconnected system and the individual companies' own load and generation are performed to determine the economic interchange of energy between companies. Several methods of cost reconstruction are available to compute the individual company costs in the total system environment. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus.

In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and on the flows on selected transmission lines for all hours in the year, as well as identifying the companies responsible for the flows on a given line.

Because of its detailed representation of the transmission system, MAPS can be used to study issues that often cannot be adequately modeled with conventional production costing software. These issues include:

- **Market Structures –** MAPS is being used extensively to model emerging market structures in different regions of the United States. It has been used to model the New York, New England, PJM and California ISOs for market power studies, stranded cost estimates, and project evaluations.

- **Transmission Access –** MAPS calculates the hour spot price ($/MWh) at each bus modeled, thereby defining a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.
- **Loop Flow or Uncompensated Wheeling –** The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify the companies contributing to the flow on a given transmission line and to define the production cost impact of that loading.
- **Transmission Bottlenecks –** MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year these lines are limiting. Next, the program can be used to assess, from an economic point of view, the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators for alleviating bottlenecks.
- **Evaluation of New Generation, Transmission, or Demand-Side Facilities –** MAPS can evaluate which of the available alternatives under consideration has the most favorable impact on system operation in terms of production costs and transmission system loading.
- **Power Pooling –** The cost reconstruction algorithms in MAPS allow individual company performance to be evaluated with and without pooling arrangements, so that the benefits associated with pool operations can be defined.

Table 1 shows how MAPS models the bulk power system and yields an accurate through-time simulation of system operation.

Table 1

MAPS Models the Bulk Power System

Generation	Transmission	Loads	Transactions
– Detailed Representation	– Tracks Individual Flows	– Chronological by Bus	– Automatic Evaluation
– Secure Dispatch	– Obeys Real Limits	– Varying Losses	– Location Specific

2. Modeling Capabilities

MAPS has evolved to study the management of a power system's generation and transmission resources to minimize generation production costs while considering transmission security. The modeling capabilities of MAPS are summarized below:

- **Time Frame –** One year to several years with ability to skip years.
- **Company Models –** Up to 175 companies.
- **Load Models** – Up to 175 load forecasts. The load shapes can include all 365 days or automatically compress to a typical week (seven different day shapes) per month. The day shapes can be further compressed from 24 to 12 hours, with bi-hourly loads.
- **Generation –** Up to 7,500 thermal units, 500 pondage plants, 300 run-of-river plants, 50 energy-storage plants, 15 external contracts, 300 units jointly owned, and 2,000 fuel types. Thermal units have full and partial outages, daily planned maintenance, fixed and variable operating and maintenance costs, minimum down-time, must-run capability, and up to four fuels at a unit.
- **Network Model –** 50,000 buses, 100,000 lines, 145 phase-angle regulators and 100 multi-terminal High-Voltage Direct Current lines. Line or interface transmission limits may be set using operating nomograms as well as thermal, voltage and stability limits. Line or interface limits may be varied by generation availability.
- **Losses** - Transmission losses may vary as generation and loads vary, approximating the ac power flow behavior, or held constant, which is the usual production simulation assumption. The incremental loss factors are recalculated each hour to reflect their dependence on the generation dispatch.
- **Marginal Costs –** Marginal costs for an increment such as 100 MW can be identified by running two cases, one 100 MW higher, with or without the same commitment and pumped-storage hydro schedule. A separate routine prepares the cost difference summaries. Hourly bus spot prices are also computed.
- **Operating Reserves –** Modeled on an area, company, pool and system basis.
- **Secure Dispatch –** Up to 5,000 lines and interfaces and nomograms may be monitored. The effect of hundreds of different network outages are considered each study hour.
- **Report Analyzer –** MAPS allows the simulation results to be analyzed through a powerful report analyzer program, which incorporates full screen displays, customizable output reports, graphical displays and databases. The built-in programming language allows the user to rapidly create custom reports.

- **Accounting –** Separate commitment and dispatches are done for the system and for the company own-load assumptions, allowing cost reconstruction and cost splitting on a licensee-agreed basis. External economy contracts are studied separately after the base dispatch each hour.
- **Bottom Line –** Annual fuel plus O&M costs for each company, fuel consumption, and generator capacity factors.

3. MAPS Applications

The program's unique combination of generation, transmission, loads and transaction details has broadened the potential applications of a production simulation model. Since both generation and transmission are available simultaneously with MAPS, the user can easily evaluate the system and company impacts of non-utility generation siting and transmission considerations.

In addition to calculating the usual production cost quantities, MAPS is able to calculate the market clearing prices (marginal costs or bus spot prices) at each load and generation bus throughout the system. For the load buses, the price reflects the cost of generating the next increment of energy somewhere on the system, and the cost of delivering it from its source of generation to the specific bus. Because the production simulation in MAPS recognizes the constraints imposed by the transmission system, the market clearing prices include the costs associated with the incremental transmission losses as well as the costs incurred in redispatching the generation because of transmission system overloads. Figure 1 shows the variation in market clearing prices of two separate companies. The company wide clearing price is the weighted average of the clearing prices at the load buses.

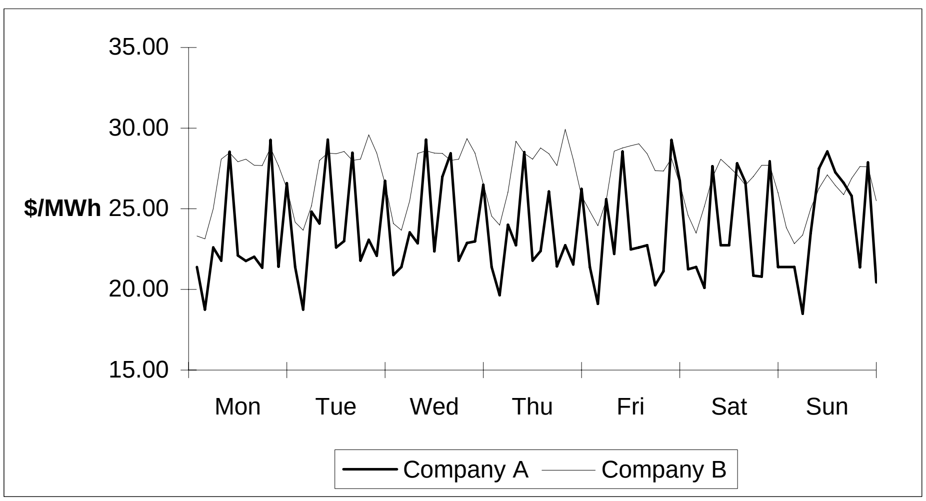


Figure 1. Market clearing prices vary with time and location.

MAPS is also able to calculate and constrain both the actual electrical flows on the transmission system and the scheduled flows assigned to individual contract paths. The actual real power flows on the network are based on the bus-specific location of the load and on the generation being dispatched to serve the load. The scheduled flows include firm company-to-company transactions that are delivered from the seller to the buyer over a negotiated path. The scheduled flows also include the generation from remotely owned units, which is delivered to the owning company over an assigned path, and generation that is delivered to remotely owned load.

The simultaneous modeling of actual and scheduled flows is especially important in modeling the Western region of the US where the scheduled flows often have a major impact on the operation of the system. Figure 2 shows the hourly flows on one of the WSCC interchange paths where the scheduled flows on the path are limiting while the actual flows are not, resulting in the generation dispatch being constrained by scheduled rather than actual physical limits. This is important in identifying the contract paths that have available transfer capability and could be used to deliver power from potential new development sites.

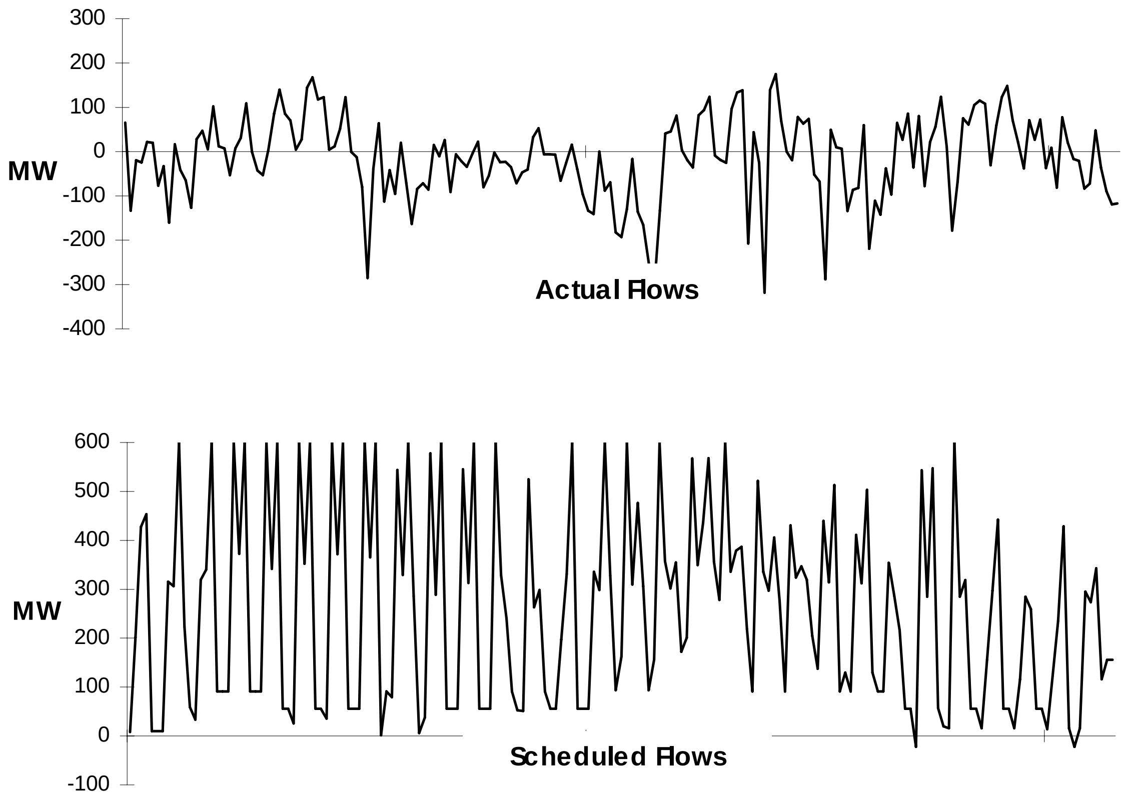


Figure 1. Example of hourly actual and scheduled flows.

4. Production Costing

MAPS models the system chronologically on an hourly basis, dispatching the generation to serve the load for all hours in a year. As a result, MAPS captures the diversity that may exist throughout the system, and accurately models resources such as energy storage and demand-side management.

Load Data

The hourly load data is input to the program in EEI (Edison Electric Institute) format for each load forecast area. These hourly load profiles are then adjusted to meet the peak and energy forecasts input to the model on a monthly or annual basis. To accurately calculate the electrical flows on the transmission system, MAPS requires information on the hourly loads at each bus in the system. This is specified by assigning one, or a combination of several hourly load profiles to each load bus.

In addition to studying all the hours in the year, MAPS can study all the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. With these modeling options, MAPS simulates the loads in chronological order and does not sort them into load duration curves.

Thermal Unit Characteristics

Essentially all the thermal unit characteristics input to MAPS can be changed on a weekly, monthly or annual basis. The following are the characteristics that can be modeled:

- Each unit can have up to seven loading segments (power points).
- Generating units can burn a blend of up to three fuel types in addition to the start-up fuel. The percentage of each fuel burned can vary by unit power point. Minimum fuel usage and maximum fuel limits are modeled and enforced on a monthly basis. If the maximum fuel limit is reached, the affected units will be switched to an alternate fuel. Economic fuel switching is also modeled.
- MAPS models fixed O&M in $/kW/year and variable O&M in $/MWh and $/fired hour. The user controls whether the variable O&M is included in determining the order for unit commitment and dispatch. A separate bidding adder in $/MWh can also be input for each unit. This cost is added to the costs used to determine the commitment and dispatch order of the units, but is ignored when computing actual unit costs.

- MAPS calculates start-up costs as a function of the number of hours that the unit has been off-line. The user can specify whether the start-up should be included in the full-load costs used to determine the order in which the units are committed.
- In the unit commitment process, MAPS models the minimum downtime and uptime on thermal units. Units can also be identified as must-run with the user specifying that the entire unit is must-run, or only the minimum portion, with the remainder of the unit committed on an economic basis as needed.
- MAPS allows the user to specify the portion of each thermal unit that can be counted toward meeting the load plus spinning reserve requirements, and the portion that can be considered as quick-start capacity. A spinning reserve credit can also be taken for unused pondage hydro and energy-storage generating capacity.
- Full and partial forced outage information is specified to MAPS in terms of forced outage rates.
- Maintenance can be specified on a daily basis for any number of maintenance periods during the year. The user can also identify units as unavailable for specific hours during the day.
- The thermal generating units bid into the system at their costs, based on fuel prices, O&M and emission costs, bid adders, and heat rates. Alternatively, the user can input the bid price in $/MWh by unit power point. This price will then be used in the commitment and dispatch to determine the way in which the units operate.
- MAPS allows all types of generating units (thermal, pondage, and energy storage) to be owned by more than one company in a multi-utility simulation. The output and cost of these units are allocated to the owning companies based on the user-specified percentages.
- Nearly all unit characteristics including rating, heat rates, and costs, can change on a weekly basis.

Models for Production Costing

The following sections describe various portions of the production simulation process in MAPS.

Hydro and energy-storage scheduling - MAPS offers three distinct representations for modeling hydro plants: hourly modifiers, pondage modifiers or energy-storage devices. This flexibility allows the program to accurately model each hydro plant based on its operating characteristics.

Hourly modifiers allow the user to specify the actual hour-by-hour operation of the plant in MW. This data can be specified for the 168 hours of a typical week of operation, with the option to change this data on a monthly basis. Alternatively, the hourly operation for the entire year (8,760 or 8,784 hours) can be input. This feature can also be used to model firm company transactions that can be specified on an hourly basis.

Hydro plants can also be modeled as *pondage modifiers*. Each pondage modifier is defined by a monthly minimum and maximum capacity (MW) and a monthly available energy (MWh). The minimum capacity is base-loaded for all hours in the month, representing the run-of-river portion of the plant. The remaining capacity and energy are scheduled in a peak-shaving or valley-filling mode over the month. The user identifies the specific load shape to use for scheduling the plant; options include the system load, combinations of selected company loads, or combinations of selected area loads. If several pondage units are located at sequential dams on the same river, they can be scheduled as a group to coordinate the operation of the units.

MAPS allows the user to develop scenarios for different water conditions (e.g., low, average, or high stream flows) through simple modifications to the available energy specified for the pondage modifiers.

For *energy-storage* devices, which include pumped-storage hydro and batteries, MAPS automatically schedules the operation based on economics and the characteristics of the storage device. The characteristics specified include the charging (or pumping) and generating ratings, the maximum storage capacity in MWh, the full-cycle efficiency (which recognizes losses in the pump/generate cycle), and the scheduling period (daily or weekly). The program examines the initial thermal unit commitment to develop a cost curve for the week. This cost curve is then combined with the appropriate chronological load profile to develop an hourly schedule, which minimizes costs without violating the storage constraints. This schedule is locked-in and the thermal unit commitment process is repeated to develop the final commitment schedule.

For all three hydro representations, the user also specifies the ownership of the plant, energy costs in $/MWh, and the transmission system bus or buses at which the plant is located. For each hourly modifier and pondage plant, you can also specify an economic dispatch price in $/MWh. If, during the dispatch of the thermal generation, the spot price at the unit's bus drops below the specified value, the unit's output will be backed down to its minimum rating (or 0 in the case of hourly modifiers) and the energy will be shifted to hours later in the week when the spot price is higher.

Dispatchable load management and non-dispatchable renewable - MAPS can model some types of dispatchable DSM and load control as thermal generating units with the appropriate characteristics and costs. Load management strategies such as batteries or thermal energy storage can be modeled as energy-storage devices.

MAPS models non-dispatchable DSM and load control and renewables such as photovoltaic or wind energy as hourly modifications to the load. This modification can be specified for the 168 hours of a typical week, with the option to change this data on a monthly basis, or by specifying the data for the entire year (8,760 or 8784 hours).

The generating units used to represent DSM, load control, and renewables can be assigned to the appropriate areas and buses throughout the system to accurately capture the dispersed nature of such resources.

Maintenance scheduling - The unit planned outages can be specified by the user, in terms of the starting and stopping dates of the maintenance period, or automatically scheduled by the program. If being scheduled by the program, the maintenance requirements can be specified as weeks of maintenance or a planned outage rate. The program schedules the maintenance on a weekly basis so as to levelize reserves (the difference between installed capacity and the sum of load plus MW on maintenance) on an area, company, pool, or system basis.

Forced outages - MAPS models the forced outages through either a Monte Carlo or recursive convolution approach. In the Monte Carlo approach, the forced outages on generating units are modeled through the use of random outages. This method is stochastic over the course of the entire year and results in the units being on forced outage for randomly selected periods during the year. The total outage time for each unit is determined by the forced outage rate, and the duration of each outage period, also known as the "mean-time-to-repair," can be specified by unit in days. Partial outages on the generating units can also be modeled, on a weekly basis. The random outage method permits accurate treatment of forced outages over the course of the year while allowing each hour to be deterministically dispatched, thus providing for the most accurate treatment of transmission limits when operating with the detailed electrical representation.

MAPS also has the capability of using the more traditional recursive convolution technique when run in the transportation mode. This technique convolves the forced outages of the units with the loads to develop an equivalent load curve each hour, allowing the calculation of expected output for each of the generating units. In this manner, a unit with a 10% forced outage rate will have a 10% probability of being unavailable for each hour of the year. This methodology is not compatible with the more detailed transmission constrained logic, but can be used with the transportation model and the transfer limits between areas.

Hourly commitment and dispatch - The objective of the commitment and dispatch algorithms in MAPS is to determine the most economic operation of the generating units on the system, subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and other operational considerations such as operating and spinning reserve requirements. The economics used for commitment and dispatch can be adjusted through the use of penalty factors that can move a unit within the commitment and dispatch ordering.

MAPS models the system chronologically on an hourly basis, committing and dispatching the generation to serve the load for all hours of the year. The unit commitment process in MAPS begins by developing a priority list of the available thermal units based on their full-load operating costs. The full-load cost is calculated from the fuel price and full-load heat rate, and can optionally include the variable O&M costs, start-up costs, and a bid adder. Alternatively, the full-load cost can be based on the bid prices that were input by unit section. This priority ordering of the thermal units is used for the entire week.

The units are then committed in order of increasing full-load costs to meet the load plus spinning reserve requirements on an hourly basis, recognizing transmission constraints. This preliminary commitment for the entire week is then checked to see if any units need to be kept on-line because of minimum downtime or minimum run-time constraints.

One potential shortcoming of this process is that baseload units, which tend to be committed first because of their lower full-load costs, may be committed for just a few hours during the week to meet load plus spinning reserve, but are then kept on-line, usually at part-load, because of the minimum downtime constraints. Consequently, the average cost of these units over the course of the week is much higher than the full-load costs that were used in determining their commitment ranking. A more economic commitment might be obtained by skipping over these units and committing intermediate or peaking units, that while they have a higher full-load cost, they can be more easily cycled from hour to hour.

The multi-pass unit commitment option is designed to commit the units based on their expected operating costs rather than their full-load costs. This is accomplished by doing the commitment in up to four passes and adjusting the daily priority costs of those units that are not committed for a specified number of hours during the day. The cost adjustment is based on the unit type (i.e., baseload, intermediate, or peaking) and an input number of hours at full, part, and minimum load operation. The type for each unit is determined from the unit's minimum downtime and input cutoff values for the minimum downtimes of baseload and peaking units. Any unit whose minimum downtime falls between these cutoff values will be modeled as an intermediate unit.

Upon completion of the commitment process for the week, the program begins the dispatch process. All of the committed units are loaded to their minimum power point, and then the program dispatches the remaining unit sections, in order of increasing incremental cost, to meet the hourly bus loads, once again recognizing the constraints imposed by the transmission system and other user-specified operating considerations.

Operational constraints - In MAPS, the production simulation is formulated as a linear programming (LP) problem where the objective function is to minimize the production costs subject to electrical and business constraints. MAPS models each security constraint as a single constraint in the LP formulation. MAPS derives these constraints from the production costing input data (for example, identified must-run units and minimum down-time for generation units) and from user-specified operating nomograms, such as those often used by system operators to represent voltage and transient stability limits. MAPS monitors the flows on individual transmission lines and interfaces on an hourly basis to ensure that the line or interface limits, or other security constraints such as import limits, are not violated while dispatching the generation system.

MAPS can also consider other user-specified contingencies such as the tripping of lines or groups of lines, or the tripping of load or generation at specified buses. The final generation dispatch developed by MAPS will be secure in the sense that the system will be operating within all its limits even under the contingency conditions.

Operating and spinning reserves - During both the unit commitment and dispatch, MAPS models operating reserve requirements for areas, companies, pools, and the entire system. The operating reserves are calculated based on a percentage of the load, a fixed MW reserve, and a percentage of continuous rating of the largest committed unit.

The total operating reserves can be met by a combination of quick-start reserves (units not actually running but which can be brought on line very quickly) and spinning reserves. The portion of operating reserves that can be met by quick-start reserves can be specified by area, company, pool, or system. The user identifies which units have quick-start capability.

A spinning reserve credit can be taken for unused generation from energy-storage units. The user can also specify the portion of each committed thermal unit that can be applied toward the spinning reserve requirements.

Emissions - MAPS models two general types of emissions. The first type of emission is a function of the amount of fuel being used. This type would typically be used to model sulfur and particulate emission. The second type of emission is a function of the unit operation, but is not directly related to the amount of fuel. This type could be used to model NOx emissions, which can decrease with increased power output.

In addition to the emission rates modeled by fuel type or by unit, the user can input, by thermal unit and emission type, the removal efficiency (in per unit) of the emission control equipment, and the removal and trading costs in dollars per ton of emission. The removal cost represents the operating costs associated with emission control equipment. The trading cost can be used to model the costs associated with the emissions that are not removed by the control equipment. These costs could include the costs related to the purchase of emission allowances.

Penalty factors on the removal and trading costs can also be input to control the extent to which these costs are included in the full-load and incremental costs used to determine the order in which the units are committed and dispatched

Representation of various power market participants - Through the appropriate assignment of loads and generation, the various participants in the power market can be represented in MAPS. Integrated utilities would have generation, transmission, and be responsible for serving load. Separate distribution entities would not own any generation but would purchase all of the energy they need to meet their load obligations. Independent power producers would be modeled as companies with generation but no transmission or load. The commitment, dispatch, and cost allocation functions in MAPS itself would represent the independent system operator. The wholesale power broker would be modeled as a company with firm contracts to buy energy from other companies, which would then be resold on a firm or economy basis.

MAPS models bilateral contracts between market participants as firm transactions between the selling and buying companies. These contracts can be specified in terms of hourly MW values, or as minimum and maximum MW ratings and available monthly energy that would be scheduled by the program.

Purchase and sale contracts - MAPS can model internal transactions (purchases and sales contracts) between companies with the system, and external transactions with companies outside the study system.

The internal transactions can be either “firm” or “economy.” Firm transactions between companies can be specified in MW on an hourly basis, or as a minimum and maximum rating (MW) and a monthly energy (MWh), which can be scheduled by MAPS. The firm transactions occur regardless of economics. The economy transactions occur between companies in the system dispatch when it is cheaper for a company to purchase energy to serve its load than to generate load with its own units.

The external contracts can also be categorized as "firm" and "economy." The primary difference is that firm external contracts are evaluated as part of the base dispatch each hour, while economy external contracts involve multiple dispatches each hour to evaluate the price paid for the energy.

Firm external contracts are modeled as unit modifiers located outside the study system, but in all other respects they are treated the same as any other system generation. Company ownerships are assigned to the units, and they are modeled in the commitment and dispatch along with the local generation.

The special feature of the economy external contract logic in MAPS is that multiple dispatches are performed each hour (both with and without each economy external contract) and the price paid for the energy is a function of the change in system operating costs. This total savings is also referred to in MAPS as the delta costs. These total savings from the transactions are divided between the system and the outside world according to a specified percentage. The system savings resulting from an external economy purchase are allocated to those companies that are net buyers of energy. Similarly, any savings from an external economy sale are allocated to those companies that are net sellers of energy.

Cost reconstruction - Within a single run of the program, MAPS can perform two separate dispatches of the system generation. In the system dispatch, the entire system is dispatched to serve the load as economically as possible, subject to the constraints imposed by the transmission system. In the company own-load dispatch, each company's resources (including its firm transactions with other companies) are economically dispatched to serve its own load. The results of the two dispatches are then used to calculate the savings that result from the coordinated system dispatch versus the isolated company dispatches. Several methods of cost reconstruction are available to allocate these savings between the buyers and sellers and to compute the individual company costs in the system environment.

Furthermore, multiple pools within a system can be modeled in MAPS. MAPS has the capability to model economic energy transaction within a company's power pool, if desired in the simulation.

Hourly bus spot prices - MAPS computes hourly spot prices at individual buses. The bus spot price is the cost of supplying an additional MW of load at the bus and includes the cost of generating the energy, the cost of the incremental transmission losses, and any costs associated with re-dispatching the generation if this additional increment of load caused overloads on the transmission system. The difference in spot prices at two buses is the short-run marginal wheeling cost between these buses.

MAPS can also develop marginal costs on a company and pool basis. There are two types of marginal cost calculations in MAPS: incremental and delta. Incremental marginal costs are calculated from a single dispatch and are equal to the cost of the last increment of power generated. Delta costs are calculated from two dispatches and equal the average cost of the change in energy dispatched. The hourly marginal costs can be summarized for on-, mid-, and off-peak periods by month, season and year.

5. Transmission Network

MAPS contains two distinct models for representing the transmission system. The original approach uses a transportation model to limit the transfer between interconnected areas during the dispatch of the system generation. The second approach performs a transmission-constrained production simulation, using a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This makes it possible to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints. In the electrical representation, all physical components of the transmission system are modeled, including transmission lines, phase-angle regulators, and HVDC lines.

MAPS can also operate in the mode in which both methodologies are used simultaneously. For example, MAPS can operate the system so that both the scheduled contract flows (transportation model) and actual electrical flows are calculated, with the more restrictive limits applying. Similarly, MAPS can constrain the system based only on the transfer limits between areas while calculating the actual electrical flows throughout the system.

Most discussions about the future of power systems agree that networks will be stressed more than ever before, and the utilities will not have the luxury of observing artificial constraints. For this reason, it is important to model the actual electrical flows on the lines in addition to the transportation flows between the control areas. MAPS, with both models available, is perfectly suited to model both the current operation of a system and to examine the various ways in which the system might be operated in the future.

Transportation Model - In both the transportation and electrical representations, MAPS calculates and limits the transmission flows on an hourly basis. In the transportation mode, the utility system is modeled as discrete operating areas containing generation and load. The transmission system is represented in terms of transfer limits on the interfaces between the interconnected areas. These limits can be different for the two directions of interface flow, and can be specified on an hourly basis. These limits can also vary on an hourly basis in response to user-specified conditions as to whether or not specified units are available (for commitment) or have been committed (for dispatch).

Electrical Representation - In the electrical representation, the load and generation are assigned to individual buses and the transmission system is modeled in terms of the individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Limits can be specified for the flow on the lines and the operation of the PARs. These limits can change on an hourly basis as a function of loads, generation, and flows elsewhere on the system. Examples of the types of operating nomograms that can be modeled in MAPS include:

- transmission line or interface limit as a function of area or company load
- net imports to an area as a function of load
- simultaneous imports into an area
- minimum generation by area.

The user can control the extent to which MAPS will enforce the limits assigned to an interchange path, transmission line, or other system element. Each monitored element is assigned an overload cost in $/MWh. If violating the limit will result in production cost savings greater than or equal to the overload cost, the limit will be ignored. If the monitored element has a small overload cost, it has “soft” limits that will be monitored but will most likely not result in a significant redispatch of the generation. An element with a large overload cost will be modeled with “hard” limits that are strictly enforced and rarely, if ever, violated, necessitating a redispatch of the generation to correct the violations.

Losses - The impact of losses on the system can be calculated by using nodal loss factors. The incremental loss factor at a node is defined as the incremental change in system losses for a 1 MW increase in injection at that node (and withdrawn at the reference bus). The average loss factor represents the actual losses in the system for the given hour for a 1 MW injection at that node. A loss model based on incremental losses gives an accurate price signal to market participants of the losses at a location. However, it results in an over-collection of loss revenue since the losses calculated using incremental loss factors are twice the actual losses in the system. On the other hand, a loss model based on average loss factors collects revenues for the actual losses in the system, but does not give the correct value of locational marginal price including losses. The incremental loss model in MAPS gives the user the option to use both the average and incremental loss factors in the calculation of losses and the incremental cost of losses.

Because the loss factors in the system change from hour to hour depending on the dispatch of generation, MAPS recalculates the incremental loss factors each hour based on the commitment and dispatch. The option to use full as well as scaled incremental losses at different points in the commitment and dispatch algorithm is also available.

In addition to using the hourly loss factors to modify the delivery factors, an alternative method being considered by some ISOs is to use the loss factors to modify the the unit bids at a location, or to modify both the unit bids and delivery factors at the same time. These options are also available in MAPS.

6. Data Input/Output

The MAPS data is input through data tables that are stored as text files, which can be easily accessed and edited through standard text editors. The table structure is essentially free-format with no stringent requirements that data can be input in specific positions within a line. The table structure in MAPS is self-documenting and allows the user to freely insert comments in the data to aid in documentation.

All MAPS output is stored in binary files to allow for report generation and customization at a later date. Among the results stored in binary files are the individual unit quantities on an hourly, monthly, annual, and study period basis for the system and own-load dispatches, and the hourly interface flows. The stored results of the transmission analysis, when MAPS is run in with the detailed electrical representation, include the hourly flows and plant outputs, the limiting elements for each hour and the marginal benefit of relaxing each limiting constraint, and the hourly spot prices at specified buses.

The MAPS Report Analyzer (MRA) is an extremely powerful tool for analyzing the vast quantities of generation- and transmission-related data produced by MAPS. The MRA loads the data from the binary files into a very efficient database and allows the user to easily create customized reports and graphs through the use of built-in commands and a simple programming language.

The MRA is completely menu driven and includes several on-line help function to guide the user. The MRA has several options for plotting study results. The first option is intended to give the user a quick look at the data but does not offer all of the flexibility, such as changing scale divisions or adding text to the graphs, that is sometimes needed. The MRA also contains a separate plotting package that can be used to fine tune the appearance of plots. The third option allows the user to export the data for use with other plotting software.

The following pages show some of the reports and graphs that are readily available from the MRA or can be easily generated from data accessible through the MRA.

Table 1. MRA Unit Edit Table

NO	--NAME--	G	H	TYPE	COMPANY	--AREA--	MAX-RTG	CON-RTG	F-O-R	MN-DT	P	TOTAL-GWH	CF	P	FC(k$)	P	OMT(k$)	P	SPMIN	SPMAX
1	Unit-01	0	0	THE	Company A	ATCE_AR	36.00	36.00	0.1040	4	0	0.774	0.0024	0	103	0	1.28	0	11.04	39.81
2	Unit-02	0	0	THE	Company A	ATCE_AR	37.00	37.00	0.1040	4	0	0.777	0.0024	0	102	0	1.29	0	11.04	39.81
3	Unit-03	0	0	THE	Company A	ATCE_AR	46.00	46.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
4	Unit-04	0	0	THE	Company A	ATCE_AR	22.00	22.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
5	Unit-05	0	0	THE	JOINT	ATCE_AR	838.78	838.78	0.0610	48	0	4105.661	0.5572	0	73479	0	9063.78	0	11.04	39.81
6	Unit-06	0	0	THE	JOINT	ATCE_AR	838.78	838.78	0.0610	48	0	3974.200	0.5394	0	71273	0	8773.56	0	11.04	39.81
7	Unit-07	0	0	THE	Company B	ATCE_AR	84.00	84.00	0.1040	4	0	13.198	0.0179	0	718	0	21.85	0	11.04	39.81
8	Unit-08	0	0	THE	Company B	ATCE_AR	19.00	19.00	0.1040	4	0	0.821	0.0049	0	76	0	1.36	0	11.04	39.81
9	Unit-09	0	0	THE	Company B	ATCE_AR	86.00	86.00	0.0840	48	0	150.891	0.1997	0	5144	0	208.19	0	11.04	39.81
10	Unit-10	0	0	THE	Company B	ATCE_AR	54.00	54.00	0.0980	48	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
11	Unit-11	0	0	THE	Company B	ATCE_AR	80.00	80.00	0.0760	48	0	343.647	0.4890	0	6535	0	758.64	0	11.04	39.81
12	Unit-12	0	0	THE	Company B	ATCE_AR	9.00	9.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
13	Unit-13	0	0	THE	Company B	ATCE_AR	129.00	129.00	0.0760	48	0	555.595	0.4903	0	10386	0	1226.55	0	11.04	39.81
14	Unit-14	0	0	THE	Company B	ATCE_AR	160.00	160.00	0.0760	48	0	699.189	0.4975	0	13058	0	1543.55	0	11.04	39.81
15	Unit-15	0	0	THE	Company B	ATCE_AR	155.00	155.00	0.0980	48	0	12.013	0.0088	0	653	0	25.46	0	11.04	39.81
16	Unit-16	0	0	THE	JOINT	ATCE_AR	1031.00	1031.00	0.1660	168	0	6268.466	0.6922	0	41312	0	4151.52	0	11.04	39.81
17	Unit-17	0	0	THE	JOINT	ATCE_AR	847.20	847.20	0.0610	48	0	4478.840	0.6019	0	79801	0	9887.49	0	11.04	39.81
18	Unit-18	0	0	THE	JOINT	ATCE_AR	847.20	847.20	0.0610	48	0	4304.070	0.5784	0	76858	0	9501.69	0	11.04	39.81
19	Unit-19	0	0	THE	Company C	ATCE_AR	59.00	59.00	0.1040	4	0	1.304	0.0025	0	175	0	2.16	0	11.04	39.81
20	Unit-20	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
21	Unit-21	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
22	Unit-22	0	0	THE	Company C	ATCE_AR	37.00	37.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
23	Unit-23	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
24	Unit-24	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
25	Unit-25	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
26	Unit-26	0	0	THE	JOINT	ATCE_AR	1051.00	1051.00	0.1660	168	0	6390.057	0.6922	0	42114	0	4232.06	0	11.04	39.81
27	Unit-27	0	0	THE	JOINT	ATCE_AR	1035.00	1035.00	0.1660	168	0	6292.781	0.6922	0	41474	0	4167.63	0	11.04	39.81
28	Unit-28	0	0	THE	JOINT	ATCE_AR	1106.00	1106.00	0.1660	168	0	6724.443	0.6922	0	44318	0	4453.52	0	11.04	39.81
29	Unit-29	0	0	THE	JOINT	ATCE_AR	1106.00	1106.00	0.1660	168	0	6724.454	0.6922	0	44319	0	4453.52	0	11.04	39.81
30	Unit-30	0	0	THE	JOINT	ATCE_AR	37.93	37.93	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81

NAME	Unit name	TOTAL-GWH	Annual GWH operation
TYPE	Unit type	CF	Capacity Factor
COMPANY	Unit company	FC (k$)	Fuel Cost
AREA	Unit area	OMT (k$)	Total O&M Cost
MAX-RTG	Maximum rating in MW	SPMIN	Spot price minimum
CON-RTG	Continuous rating in MW	SPMAX	Spot price maximum
F-O-R	Forced outage rate	SPAVG	Spot price average
MN-DT	Minimum downtime (hours)		

Table 2. MAPS Standard System Report

Year -- 2000
Monthly Summary Table
****

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
SYSTEM													
Thermal Units													
ENERGY (1000s MWh)	22181	21179	19527	17531	19141	21007	26876	24109	19369	19371	20622	23239	254153
REVENUE (1000s $)	447234	448626	387184	376870	404163	435390	716990	550809	416994	415715	426702	474828	5501506
COST (1000s $)	316989	315642	290949	285241	282927	305187	438163	364271	294182	303528	305870	334249	3837198
NET $ (1000s $)	130245	132984	96235	91629	121237	130203	278827	186537	122812	112187	120831	140579	1664308
Hourly Modifiers													
ENERGY (1000s MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
REVENUE (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
COST (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
NET $ (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
Pondage Modifiers													
ENERGY (1000s MWh)	344	401	649	663	536	268	185	142	120	149	351	438	4250
REVENUE (1000s $)	7418	9049	13081	14522	11677	6024	5578	3851	2770	3300	7639	9388	94297
COST (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
NET $ (1000s $)	7418	9049	13081	14522	11677	6024	5578	3851	2770	3300	7639	9388	94297
P.S. Hydro													
GEN EGY (1000s MWh)	68	100	80	171	139	146	199	192	134	173	109	92	1601
REVENUE (1000s $)	1700	2425	1744	4533	3690	3834	6841	5673	3533	4418	2738	2252	43380
PUMP EGY (1000s MWh)	84	157	97	257	177	197	296	250	194	249	154	135	2248
NEG REV (1000s $)	1415	2830	1644	4537	2956	3259	5401	4267	3277	4268	2711	2342	38907
NET EGY (1000s MWh)	-17	-56	-17	-87	-39	-52	-98	-58	-60	-76	-45	-43	-648
NET $ (1000s $)	285	-405	99	-4	734	575	1440	1406	256	150	26	-90	4473
Total Generation													
ENERGY (1000s MWh)	22509	21524	20159	18108	19638	21223	26964	24194	19429	19443	20929	23635	257756
REVENUE (1000s $)	454937	457270	400364	391387	416575	441990	724008	556066	420020	419165	434367	484126	5600276
COST (1000s $)	316989	315642	290949	285241	282927	305187	438163	364271	294182	303528	305870	334249	3837198
NET $ (1000s $)	137948	141629	109415	106146	133648	136802	285845	191795	125838	115637	128497	149877	1763078
Load ENERGY	22509	21523	20159	18108	19638	21223	26964	24193	19429	19444	20929	23634	257754
REVENUE	455881	459494	400553	391454	416700	442119	724056	556358	420166	419184	434573	484156	5604694
Net Gen GWh - Load GWh	0	0	0	0	0	1	0	1	0	0	0	0	2
Net Gen k$ - Load k$	-317933	-317866	-291138	-285308	-283052	-305316	-438210	-364563	-294328	-303547	-306076	-334278	-384161
Congestion Cost (k$)	944	2224	189	67	125	129	47	292	146	19	206	29	4417

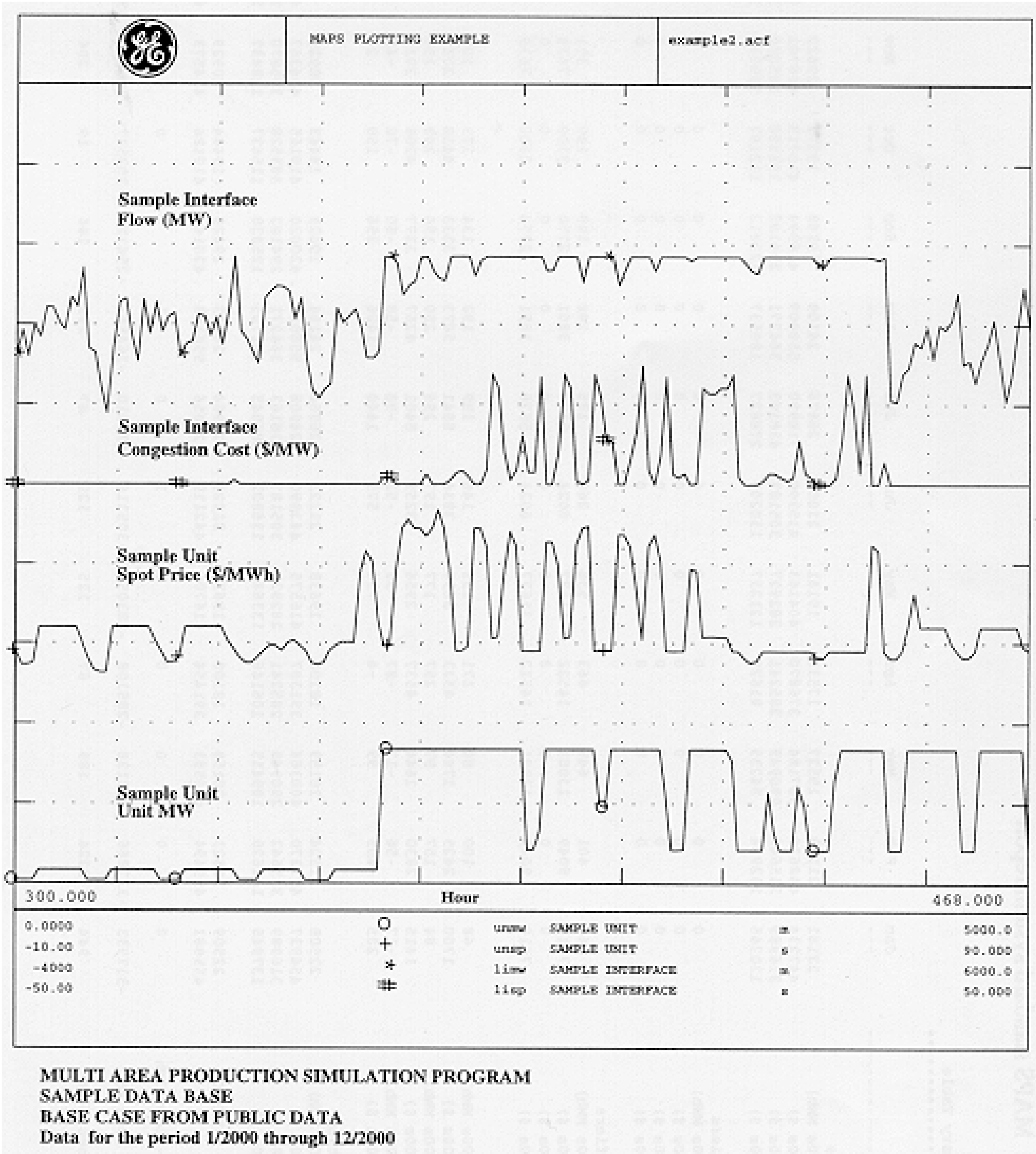


Figure 2. Typical Plots Available from MRA

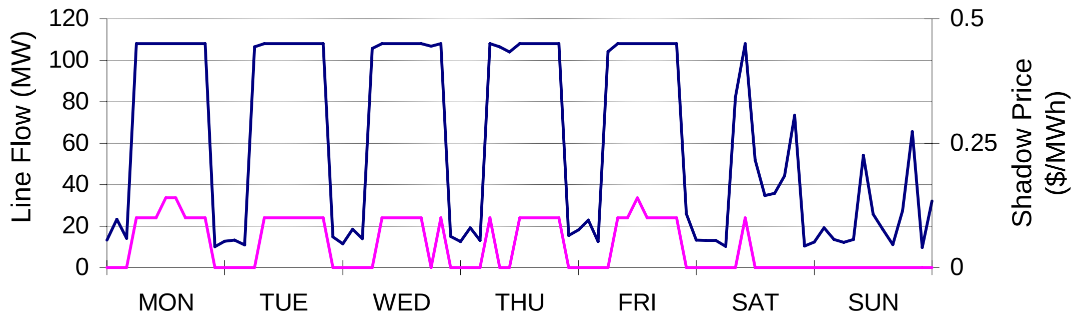


Figure 3. Line Flows and Line Shadow Prices

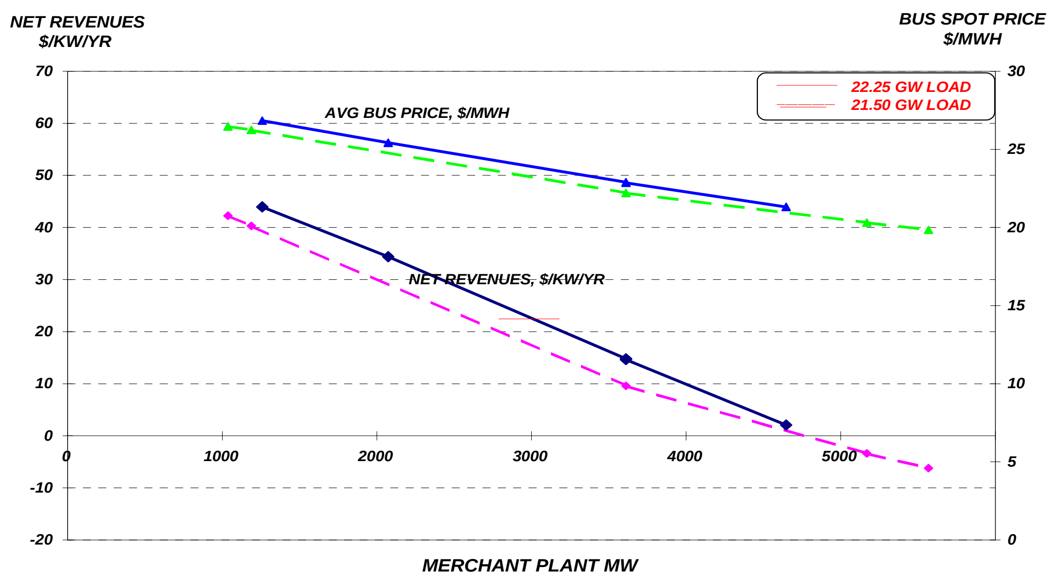


Figure 4. Merchant Plant Net Revenues

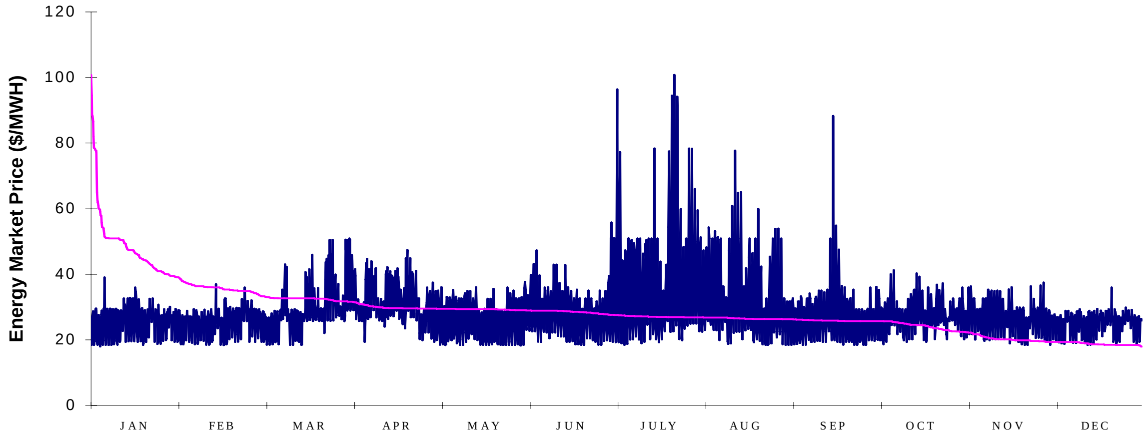


Figure 5. Hourly Market Energy Prices

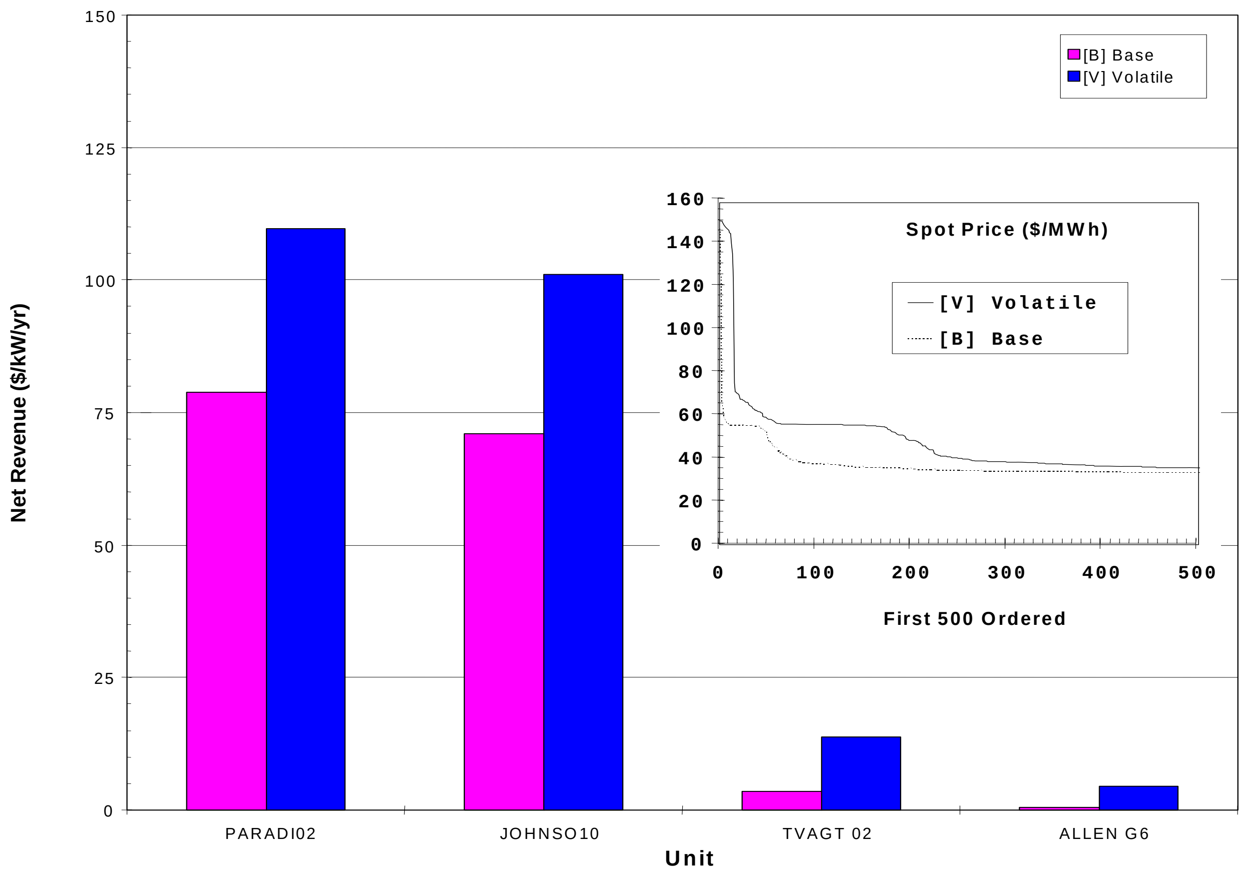


Figure 6. Effect of Market Volatility on Spot Price and Net Revenue

7. Hardware Specifications for Running MAPS and MRA

Table 3. MAPS and MRA Hardware Specifications

	PENTIUM PC
System	Pentium IV 2.5 GHz 1 GB RAM 40 GB Disk 2 Button Mouse 101 Keys (US) Floppy Disk Drive CD-ROM 56 kB Modem
Monitor	20” Color Display
Backup	CD-Writer
Op Sys	Windows NT, 95, 98, 2000, or XP
Aux Software	Exceed 7.0 from Hummingbird

8. MAPS Licensees

A list of current MAPS licensees is available on request.

9. MAPS Pricing Information

Pricing information for licensing MAPS, MAPS training, and MAPS studies conducted by GE Energy personnel is available on request.

10. MAPS Publications

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Appendix D – MARS Description

GE Energy

MARS

(Multi-Area Reliability Simulation Software)

Program Description

The Multi-Area Reliability Simulation software program (MARS) is owned and supported by GE Energy. All inquiries regarding MARS should be directed to:

Devin T. Van Zandt
Manager-Software Products
GE Energy
1 River Road
Schenectady, NY 12345
518-385-9066
devin.vanzandt@ge.com

MARS is available for installation on a personal computer with a compatible Windows operating system through a software licensing agreement with GE Energy. The program can also be accessed through contract studies performed by GE Energy's Energy Applications and Systems Engineering group.

Multi-Area Reliability Simulation Software (MARS)

The Multi-Area Reliability Simulation software program (MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

MARS MODELING TECHNIQUE

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

RELIABILITY INDICES AVAILABLE FROM MARS

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

DESCRIPTION OF PROGRAM MODELS

Loads

The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

GENERATION

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units. In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units. Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration. MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM. Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

TRANSMISSION SYSTEM

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

CONTRACTS

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

EMERGENCY OPERATING PROCEDURES

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

RESOURCE ALLOCATION AMONG AREAS

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

OUTPUT REPORTS

The following output reports are available from MARS. Most of the summaries of calculated quantities are available for each load forecast uncertainty load level and as a weighted-average based on the input probabilities.

- Summary of the thermal unit data.
- Summary of installed capacity by month by user-defined unit type.
- Summary of load data, showing monthly peaks, energies, and load factors.
- Unit outage summary showing the weeks during the year that each unit was on planned outage.
- Summary of weekly reserves by area, pool, and system.
- Annual, monthly, and weekly reliability indices - by area and pool, isolated and interconnected.
- Expected number of days per year at specified margin states on an annual, monthly, and weekly basis.
- Annual and monthly summaries of the flows, showing for each interface the maximum and average flow for the year, the number of hours at the tie limit, and the number of hours of flow during the year.
- Annual summary of energy and hours of curtailment for each contract.
- Annual summary of energy usage for the peaking portion of Type 2 energy-limited units.
- Replication year output, by area and pool, isolated and interconnected, showing the daily and hourly LOLE and LOEE for each time that the study year was simulated. This information can be used to plot distributions of the indices, which show the year-to-year variation that actually occurs.
- Annual summary of the minimum and maximum values of the replication year indices.
- Detailed hourly output showing, for each hour that any of the areas has a negative margin on an isolated basis, the margin for each area on an isolated and interconnected basis.
- Detailed hourly output showing the flows on each interface.

PROGRAM DIMENSIONS

All of the program dimensions in MARS can be changed at the time of installation to size the program to the system being studied. Among the key parameters that can be changed are the number of units, areas, pool, and interfaces.