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.

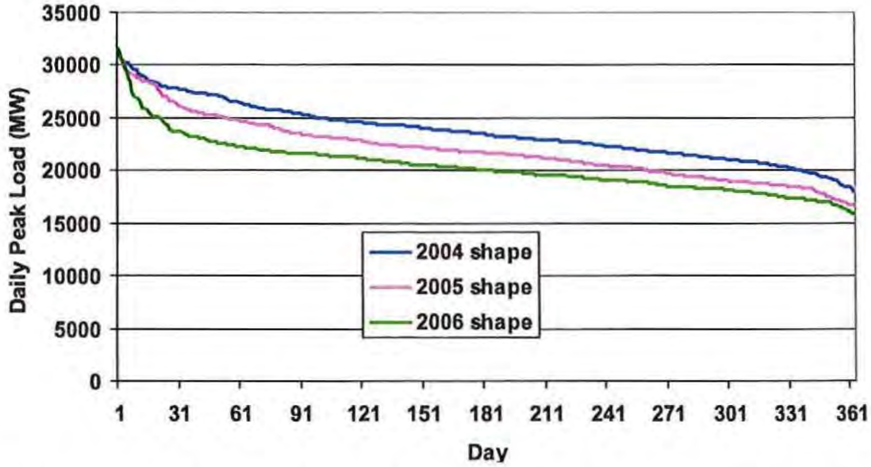

Figure 6–14 Daily peak load duration curve

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.

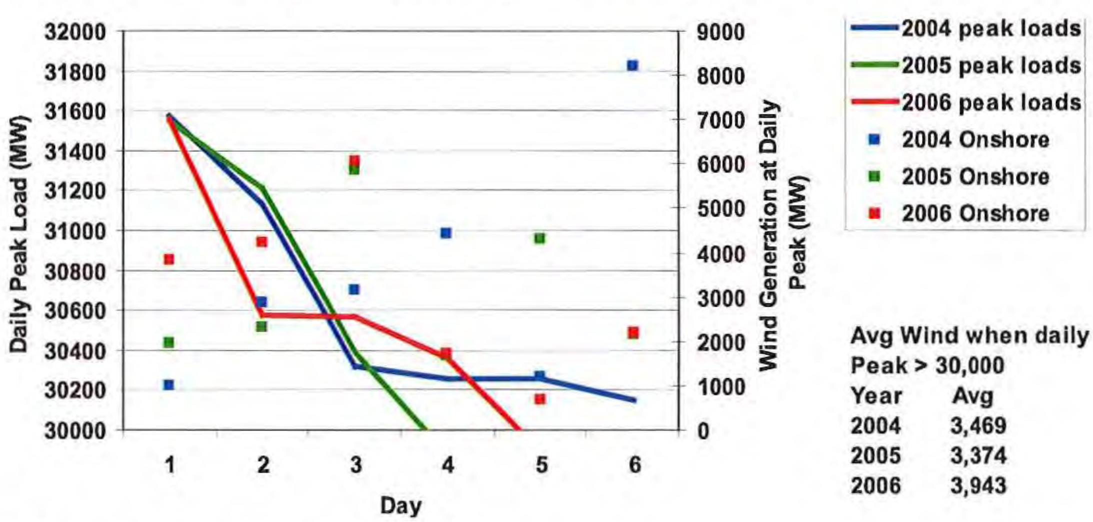

Figure 6–15 Load shapes and wind generation

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.

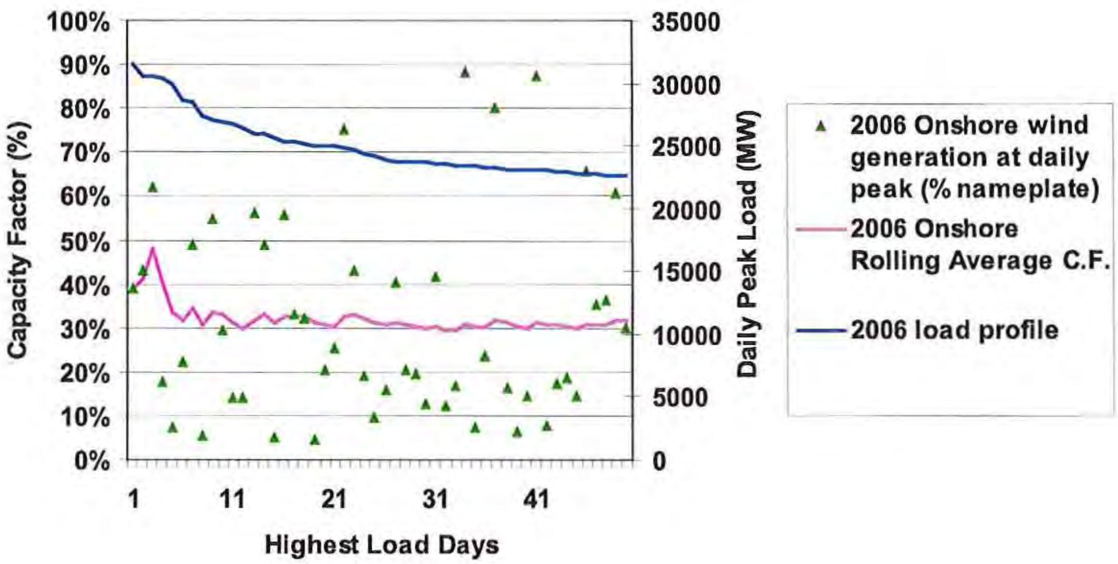

Figure 6–16 Highest Load Days, 20% Onshore Scenario, 2006 load shapes

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%.

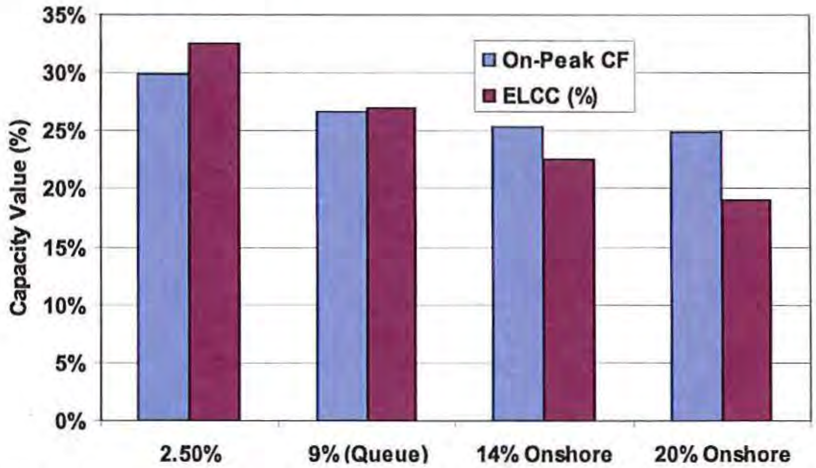

Figure 6–17 Comparison of capacity value methodologies, 2004 shapes.

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.

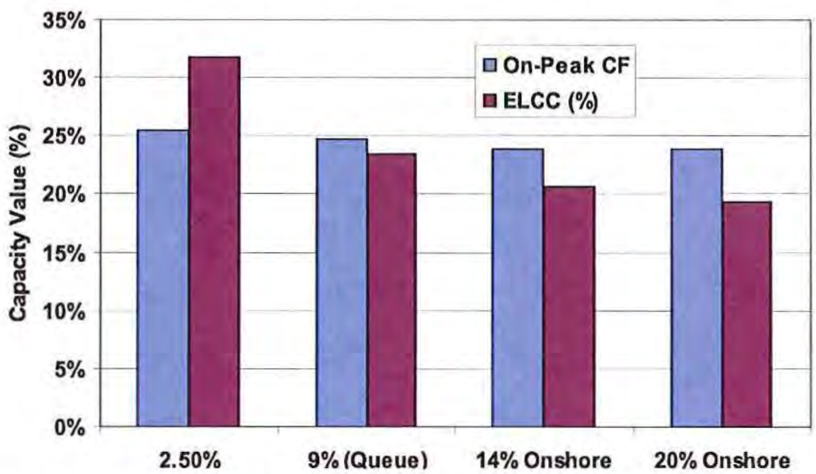

Figure 6–18 Comparison of capacity value methodologies, 2005 shapes.

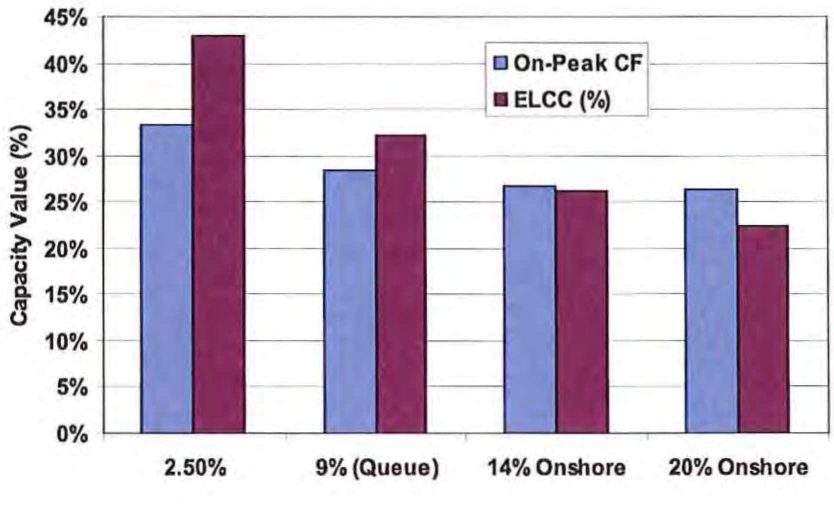

Figure 6–19 Comparison of capacity value methodologies, 2006 shapes.

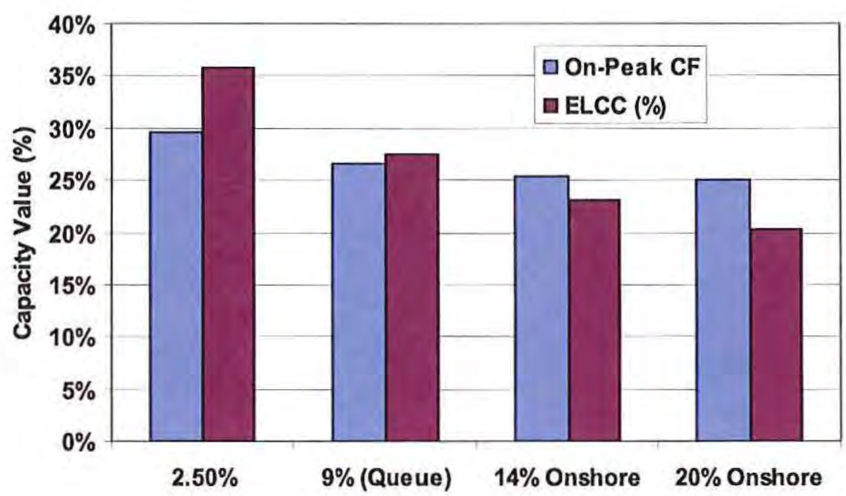

Figure 6–20 Comparison of capacity value methodologies, three year average.

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.

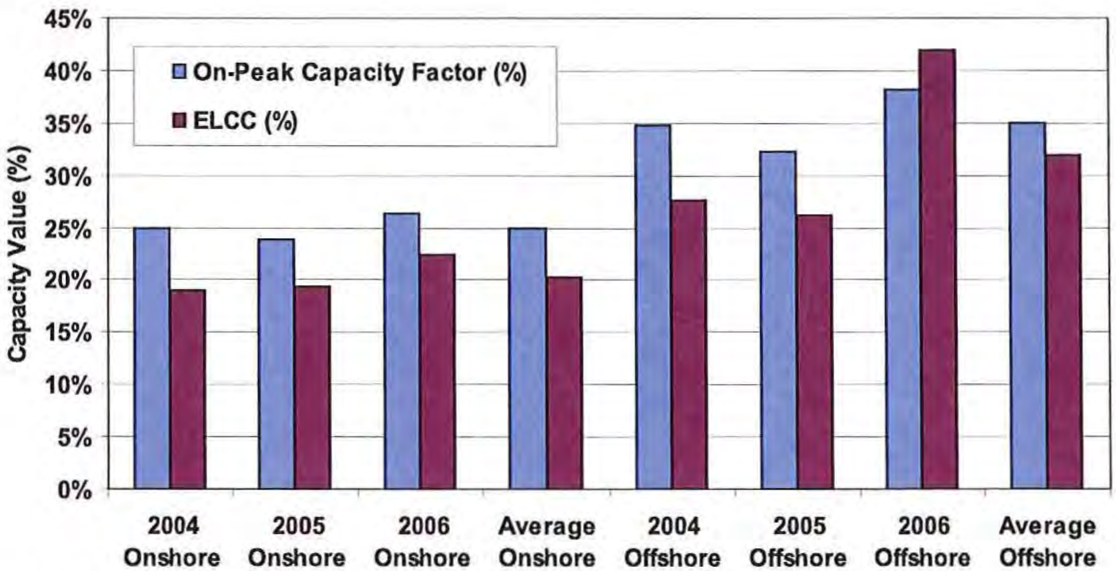

Figure 6–21 Comparison of capacity value methodologies, 20% Onshore and Offshore Scenarios.

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:

$$\text{CV CORRECTION FACTOR} = \text{CV}_{\text{TOTAL, LOLE}} / \text{CV}_{\text{TOTAL, APPROX METHOD}}$$

$$\text{CV}_{\text{PLANT}} = \text{CV}_{\text{PLANT, APPROX METHOD}} \times \text{CV CORRECTION FACTOR}$$

where,

$\text{CV}_{\text{TOTAL, LOLE}}$ = the aggregate capacity value of all wind generation in ISO-NE, calculated using LOLE methods for all hours

$\text{CV}_{\text{TOTAL, APPROX METHOD}}$ = the aggregate capacity value of all wind generation in ISO-NE calculated using the approximate method for peak load hours

$\text{CV}_{\text{PLANT, APPROX METHOD}}$ = 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.

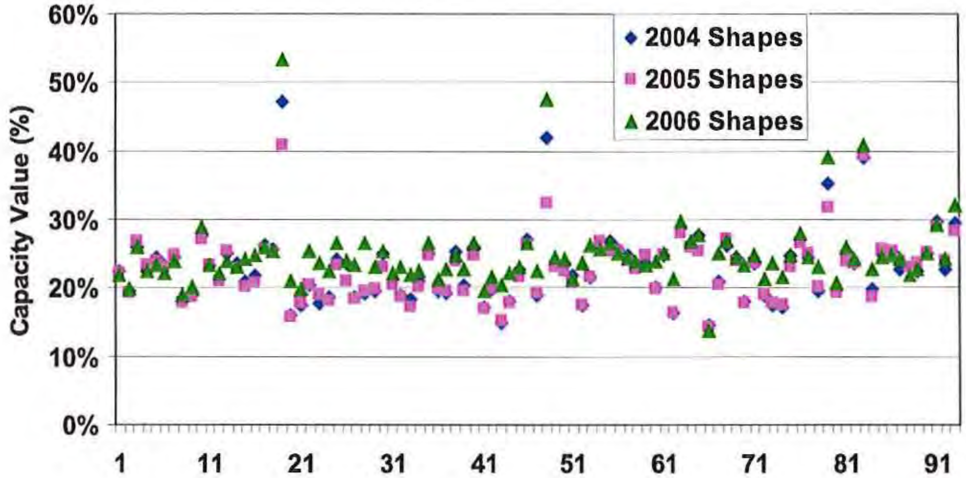

Figure 6–22 **On-peak capacity factors by site for the 20% Onshore Scenario.**

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.

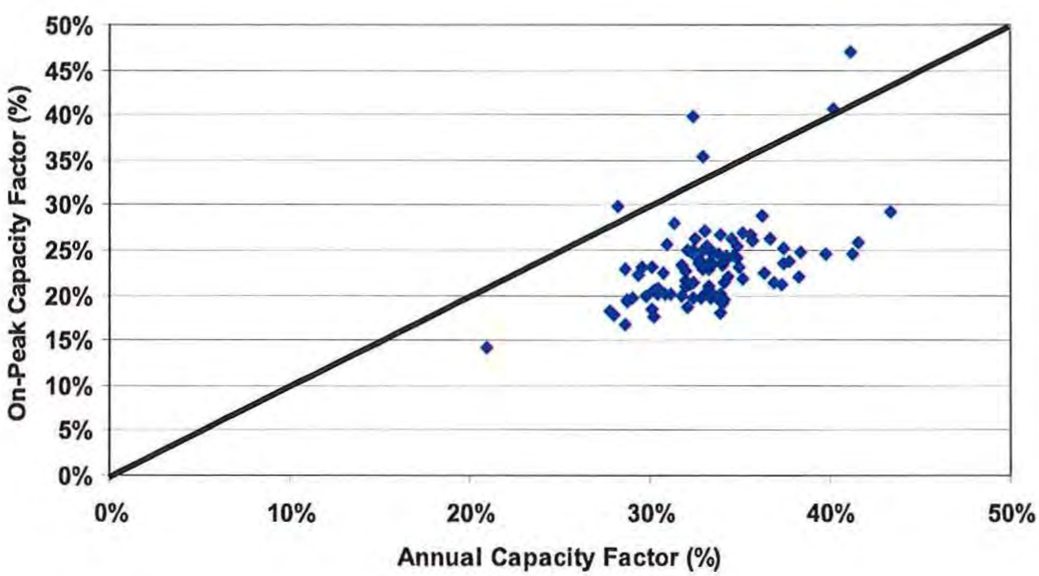

Figure 6–23 **Annual capacity factor versus on-peak capacity factor, 3 year average.**

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.

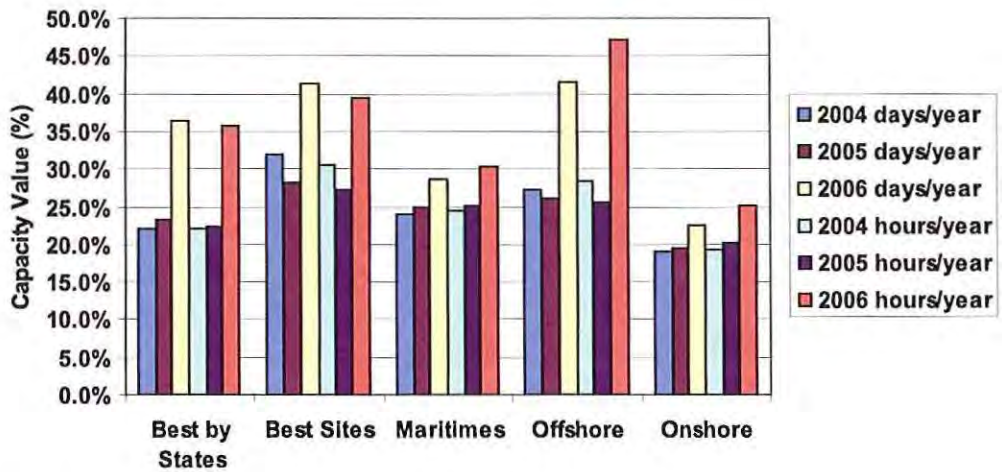

Figure 6–24 Capacity Value based on days/year versus hours/year, 20% scenario

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.

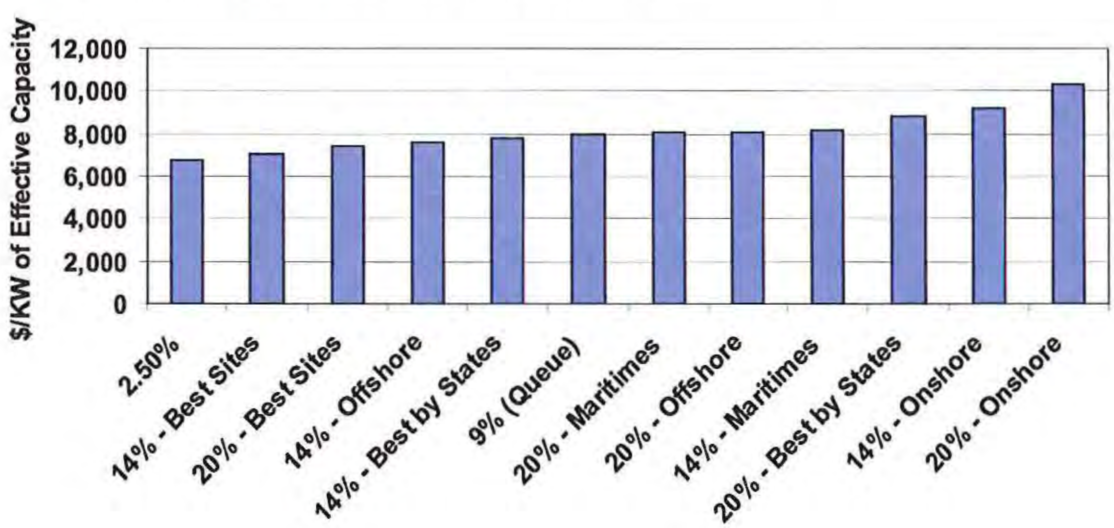

Figure 6–25 Net capital cost in $/KW of effective capacity.

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.

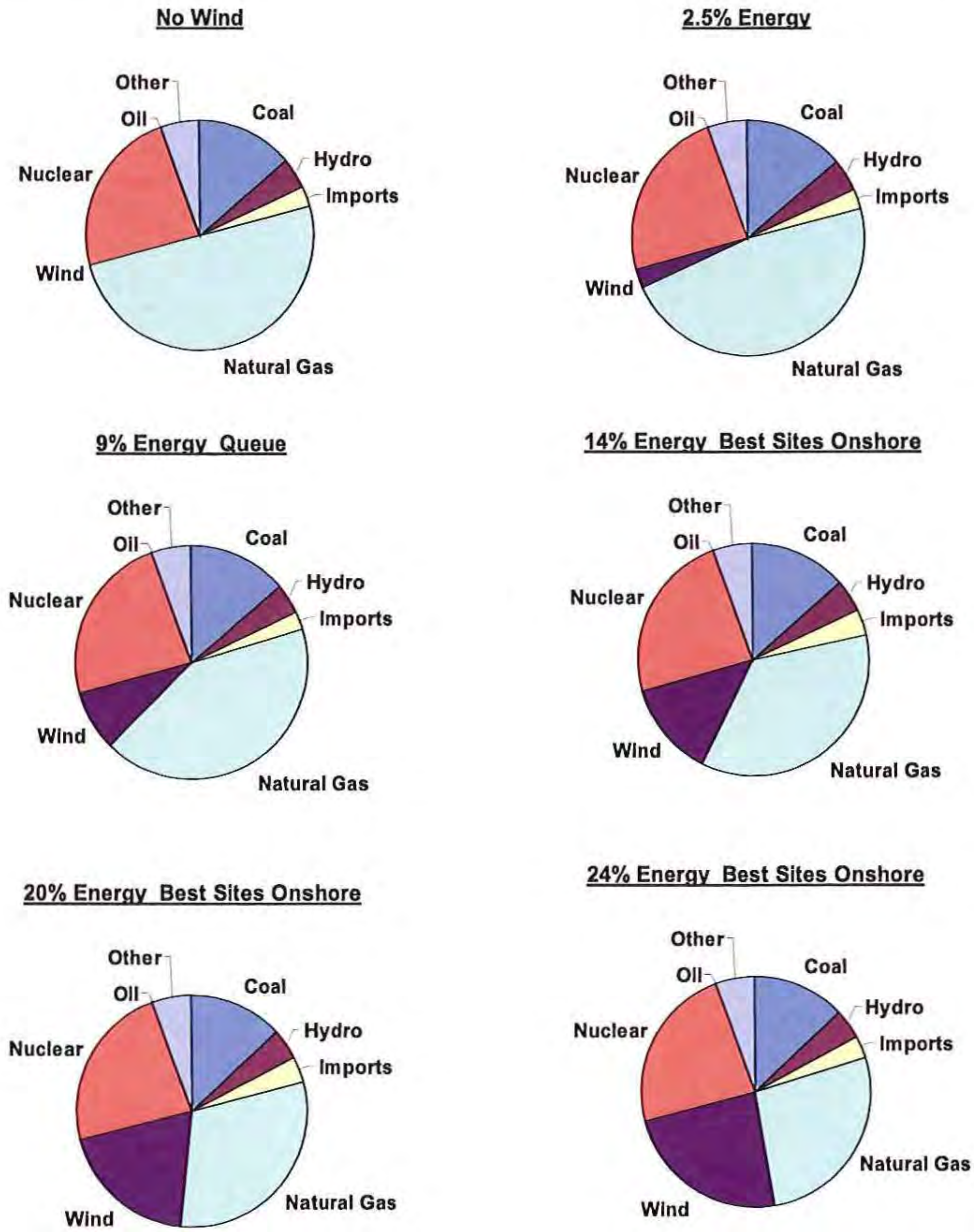

Figure 7–1 Annual Energy from ISO-NE Generation Fleet with Increasing Wind Energy Penetration.

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.

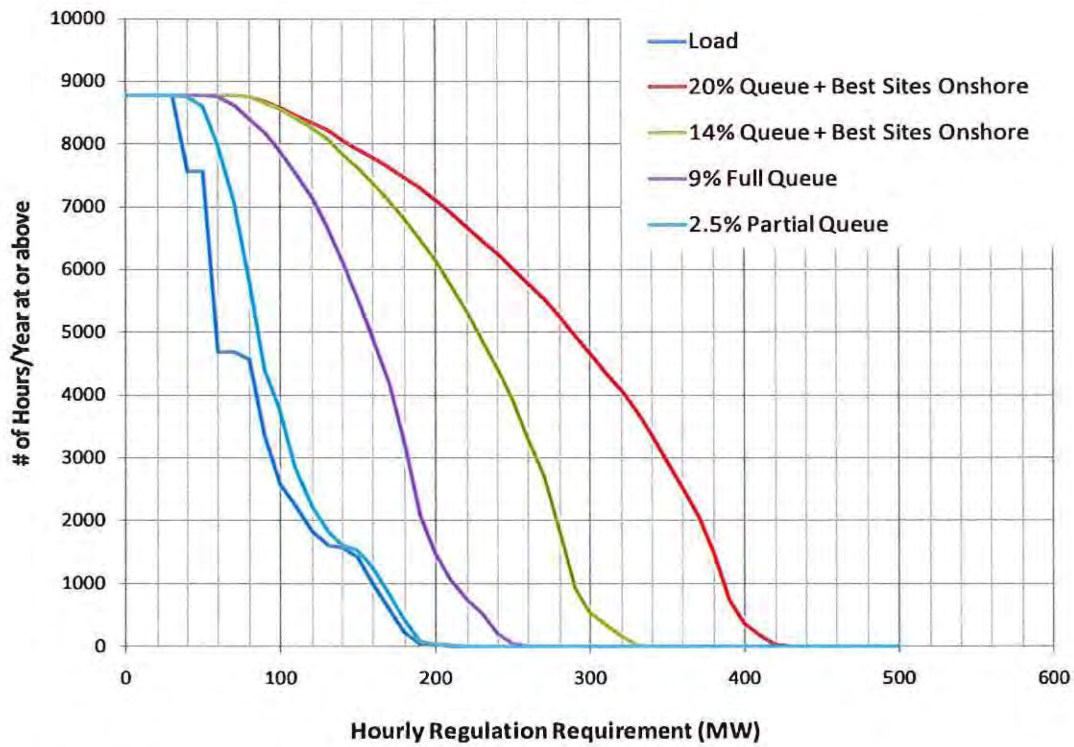

Figure 7–2 Regulation Requirements with Increasing Wind Energy Penetration

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.

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[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.

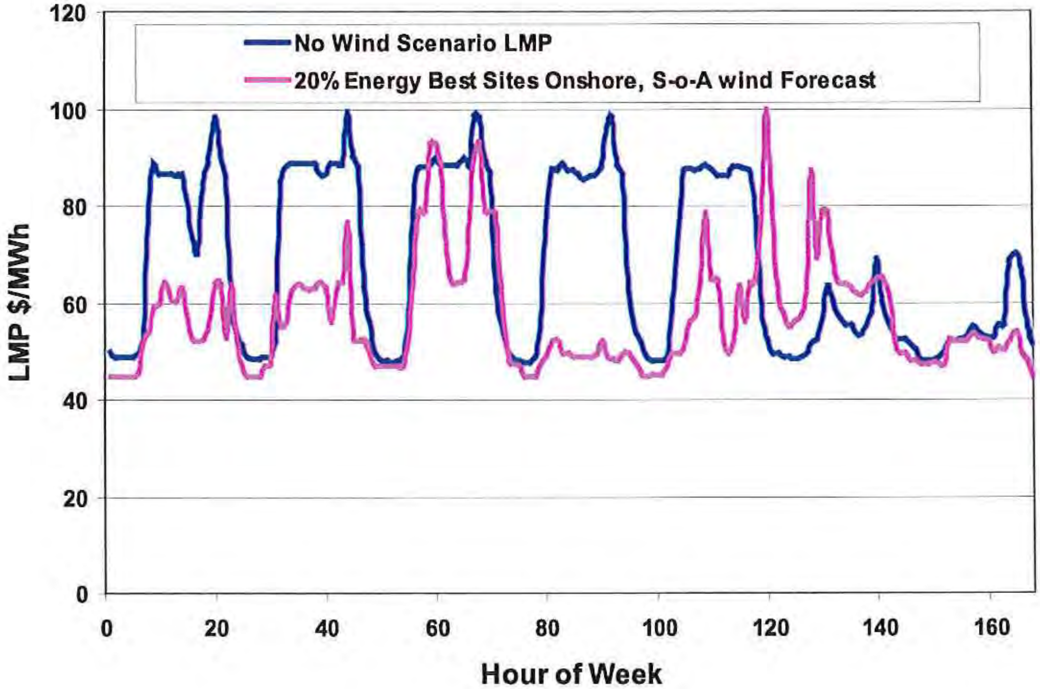

Figure 7–3 **LMP for Week of April 1, Comparison of No Wind and 20% Wind Energy**

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.

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[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.

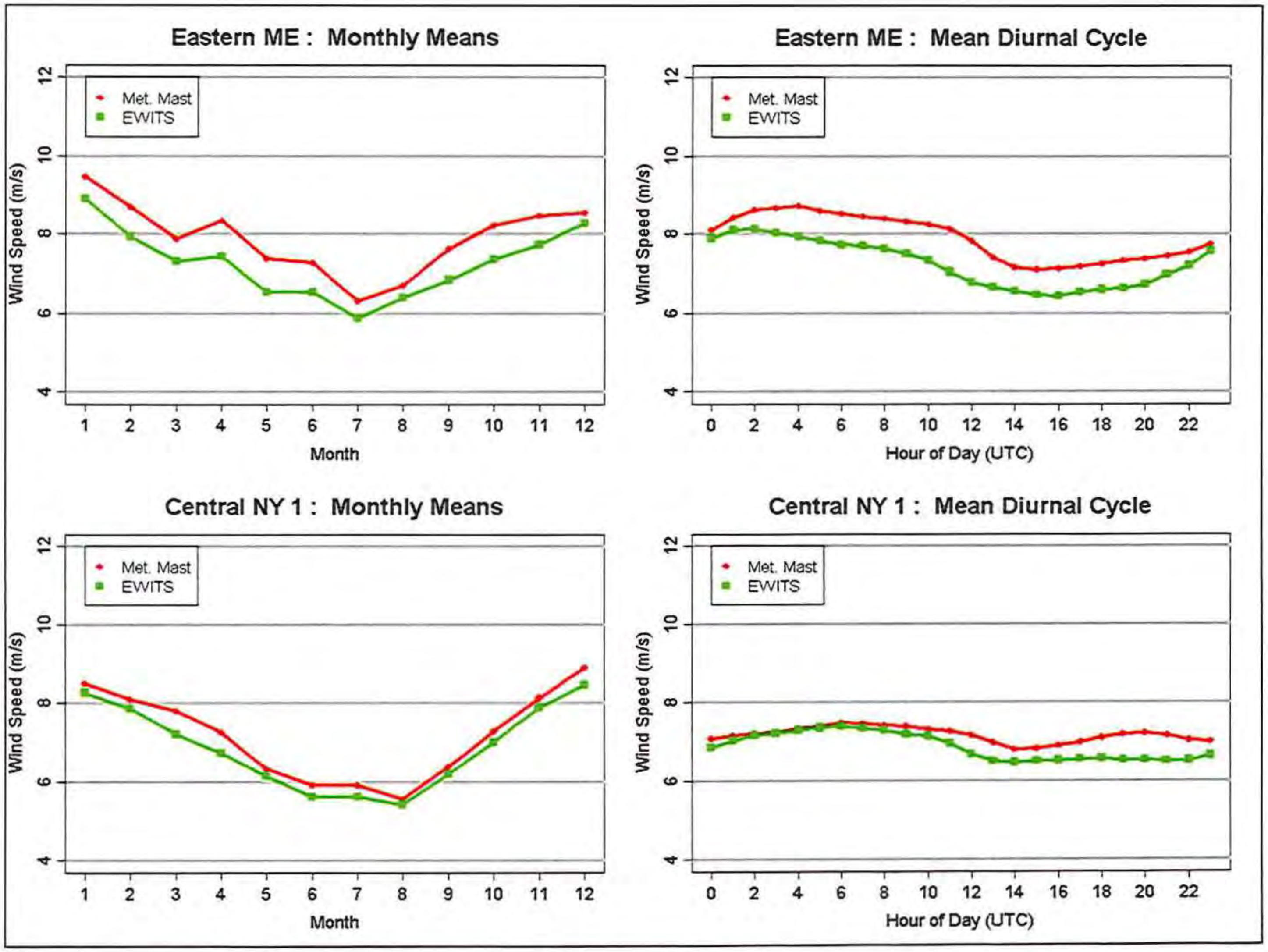


Figure A1 Wind speed validation plots for Eastern Maine and Central New York. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds are red plots represent measured wind speed data collected from tall towers)

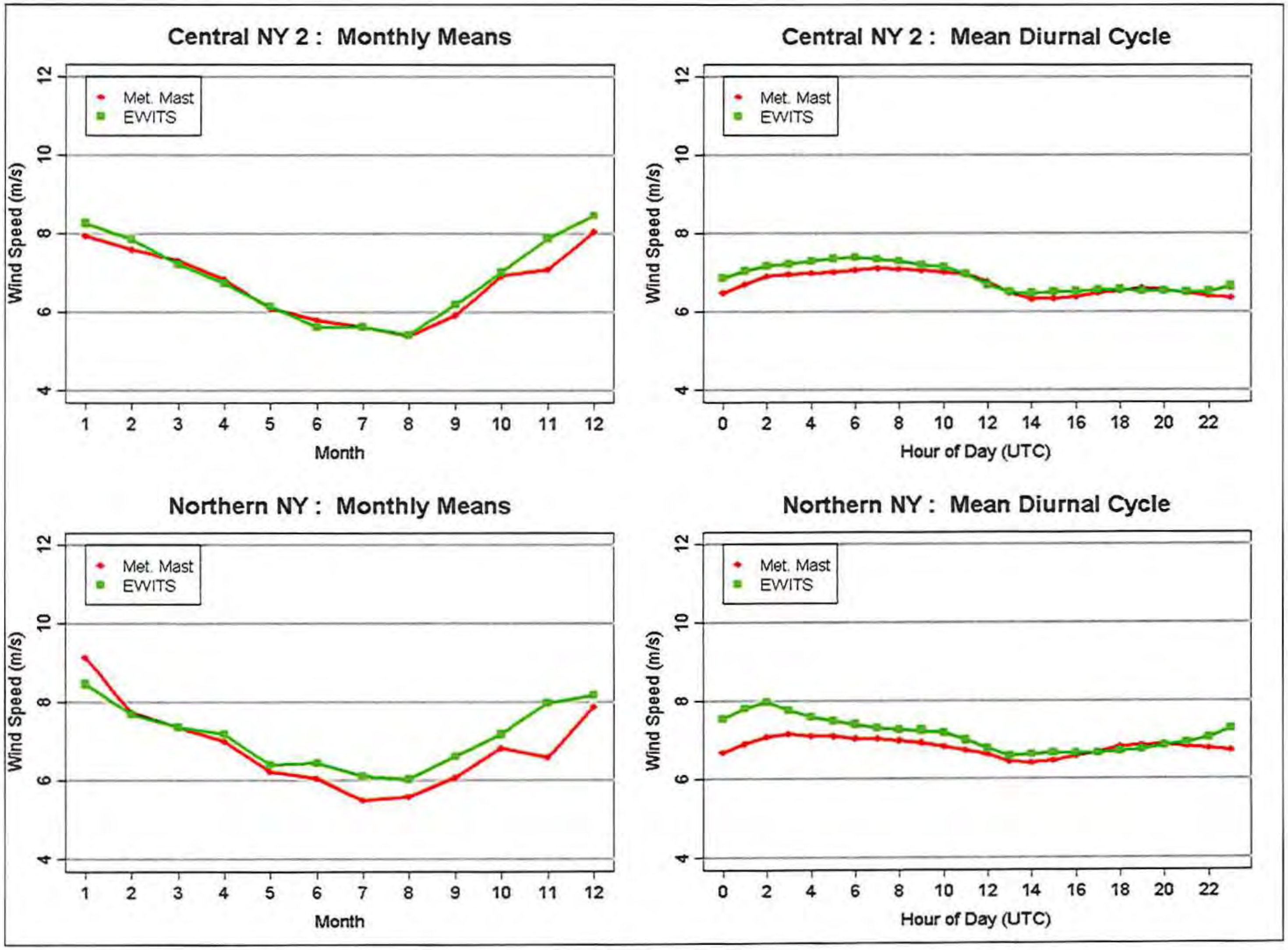


Figure A2 Wind speed validation plots for Central and Northern New York. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds are red plots represent measured wind speed data collected from tall towers)

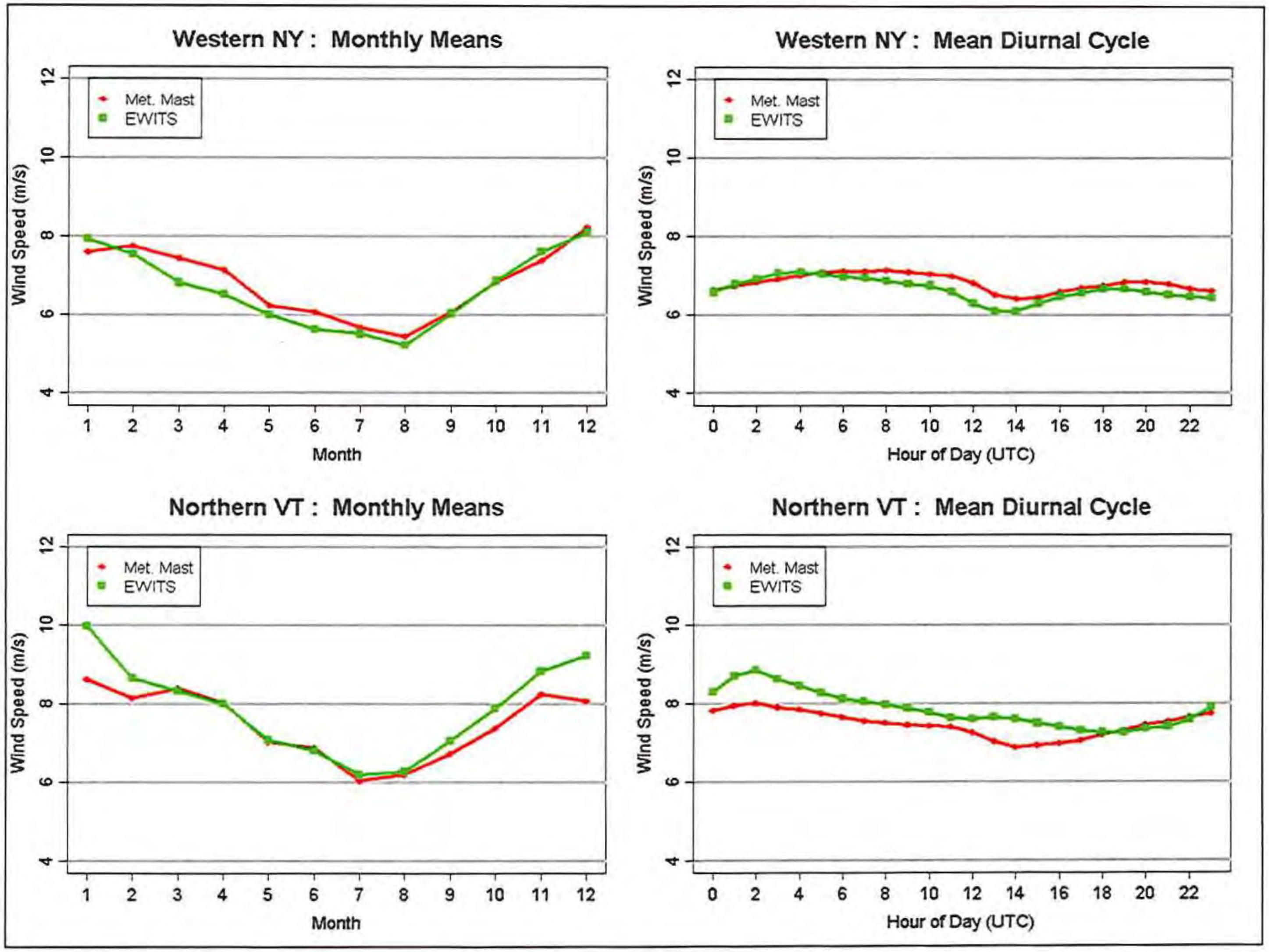


Figure A3 Wind speed validation plots for Western New York and Northern Vermont. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds are red plots represent measured wind speed data collected from tall towers)

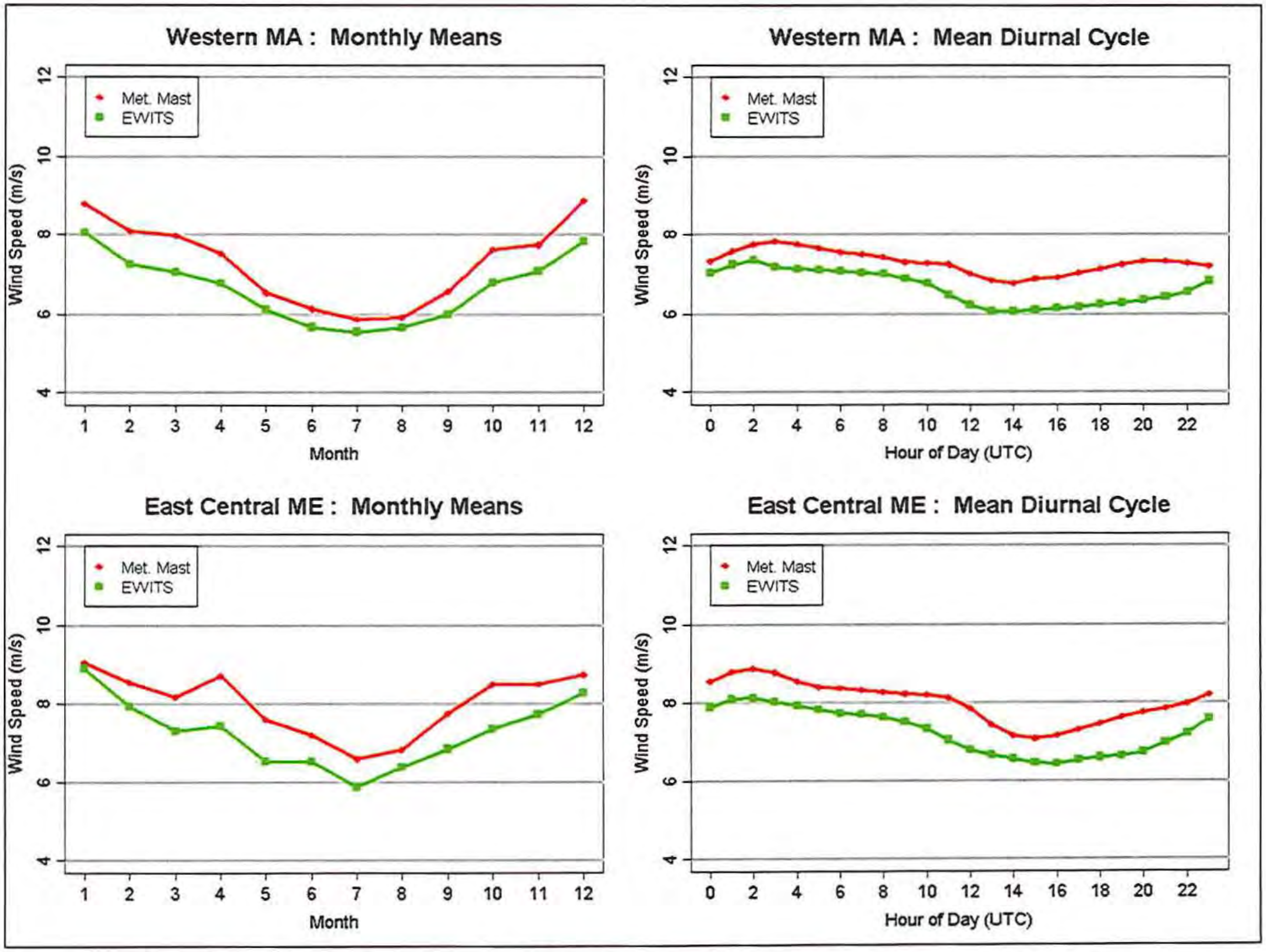


Figure A4 Wind speed validation plots for Western Massachusetts and East Central Maine. All plots represent time-matched wind speeds. (Green plots represent simulated wind speeds and red plots represent measured wind speed data collected from tall towers)

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.

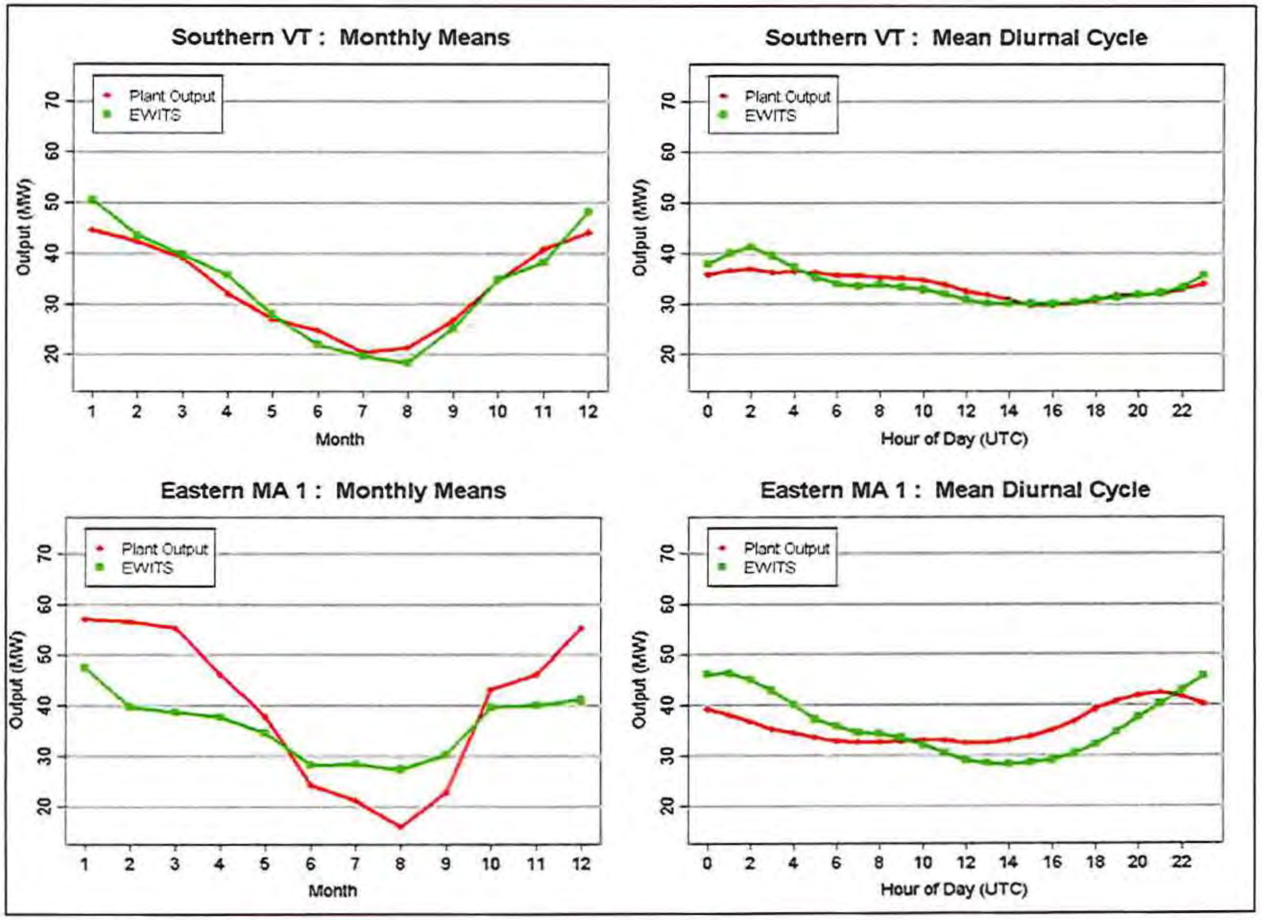


Figure A5 Plant power output validation plots for Southern Vermont and Eastern Massachusetts. (Green plots represent simulated wind plant power output and red plots represent power generation data from existing wind plants)

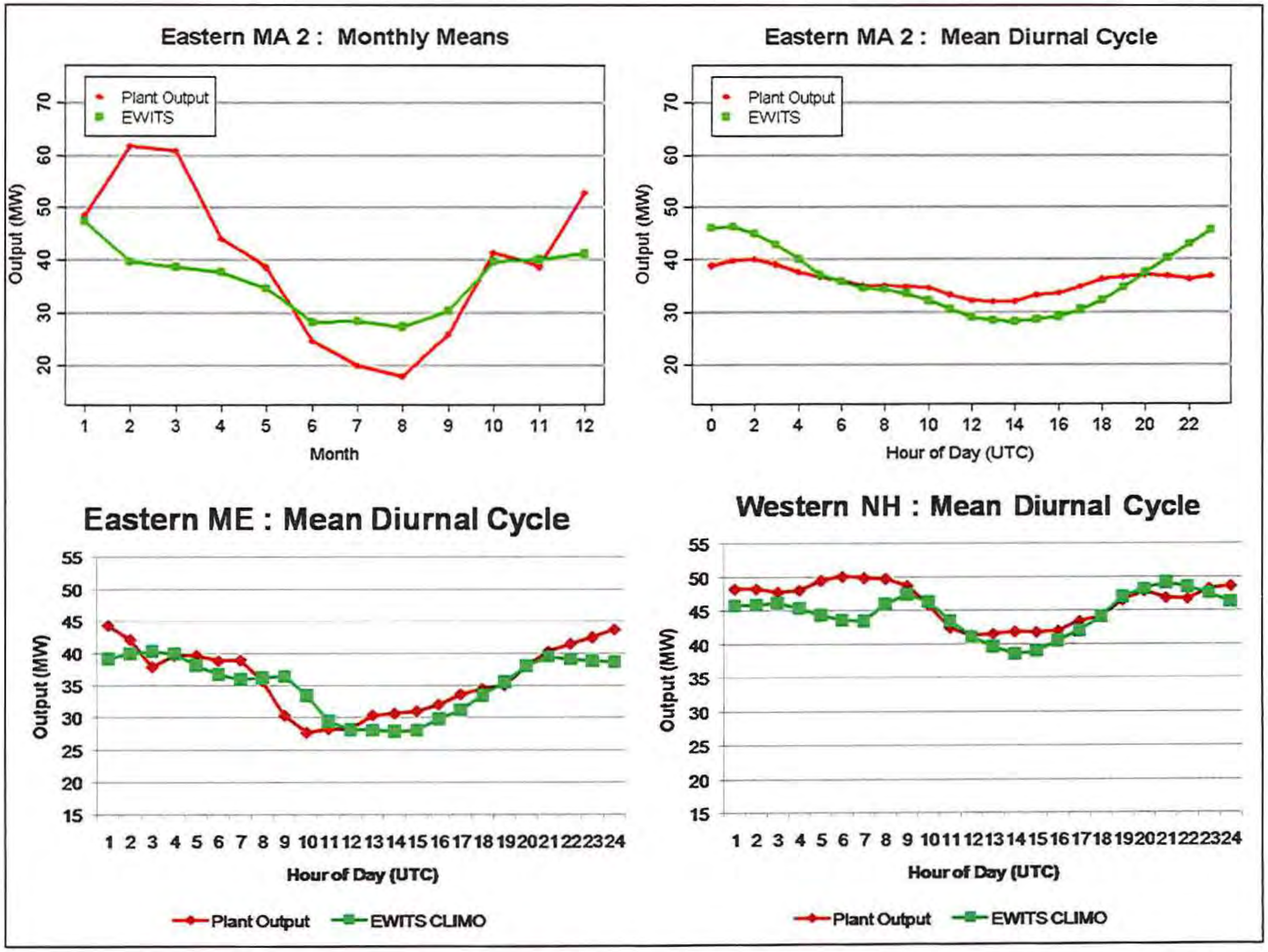


Figure A6 Plant power output validation plots for Eastern Massachusetts, Eastern Maine and Western New Hampshire. (Green plots represent simulated wind plant power output and red plots represent power generation data from existing wind plants)

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%

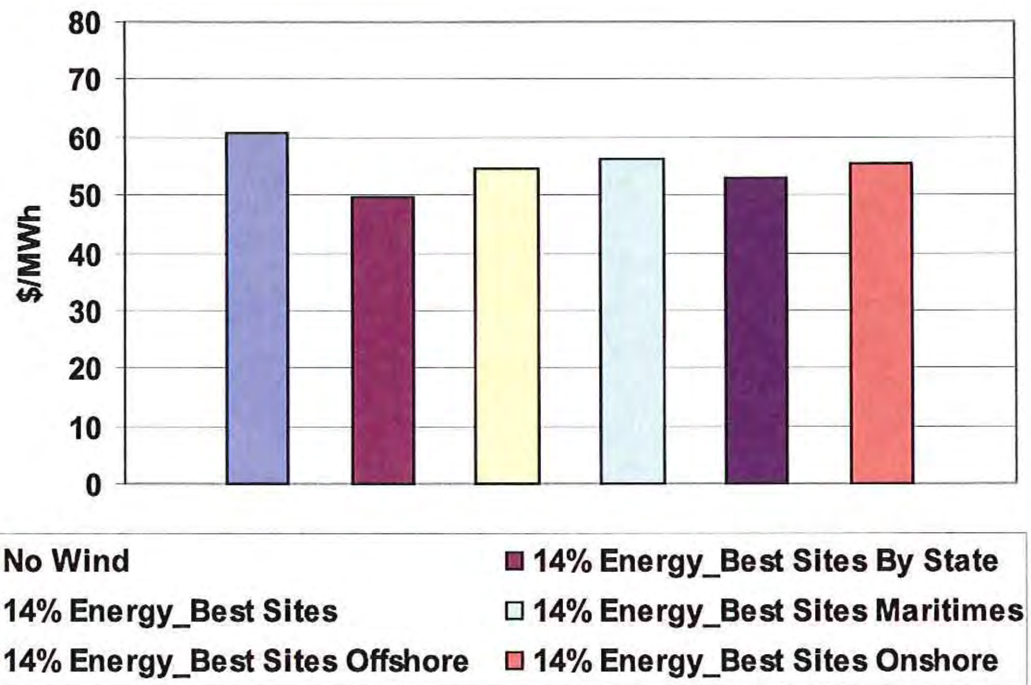


Figure B–1 Annual load weighted average ISO-NE location market price, S-O-A Forecast, 14% penetration

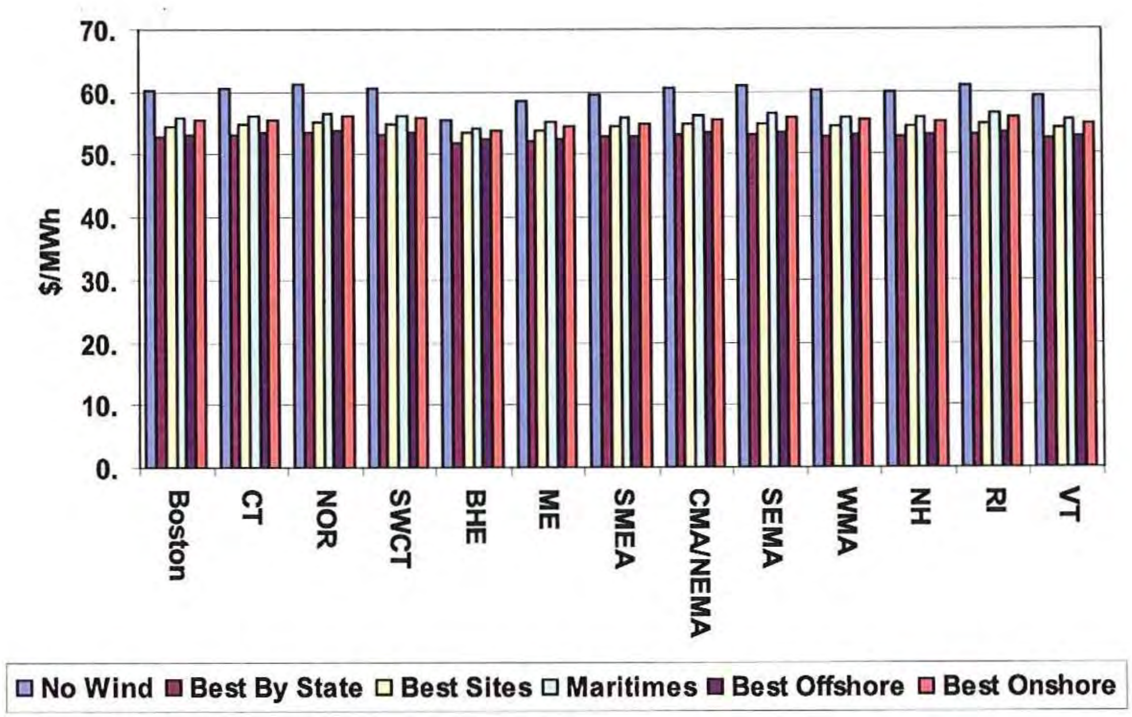


Figure B-2 Annual load weighted average ISO-NE RSP location market price, S-o-A Forecast, 14% penetration

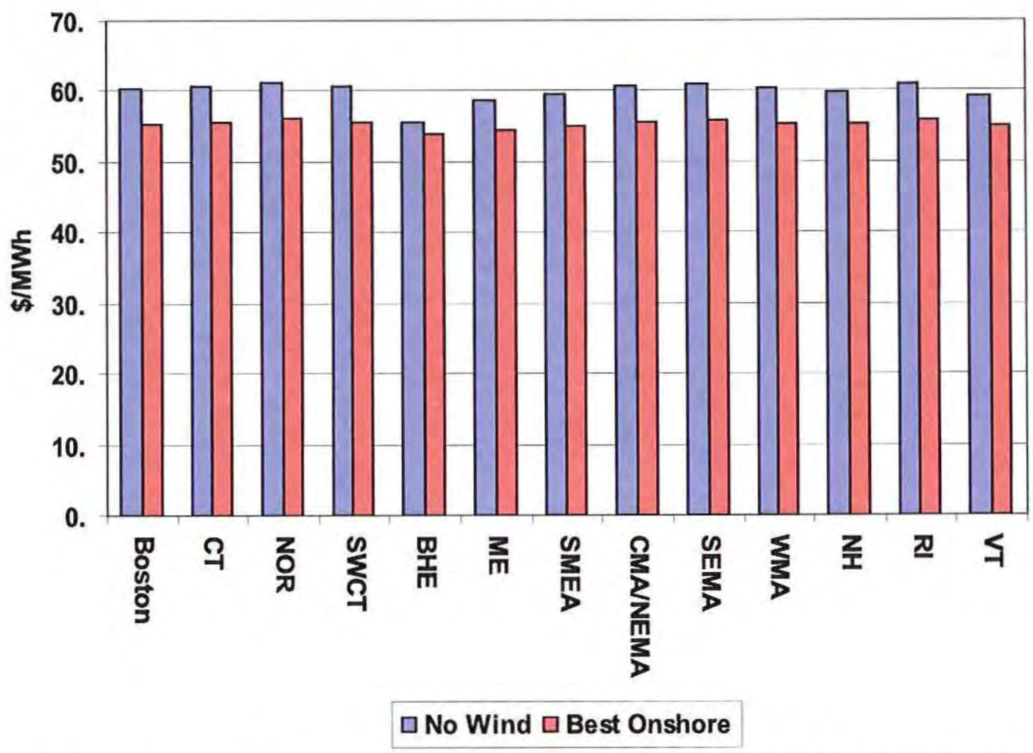
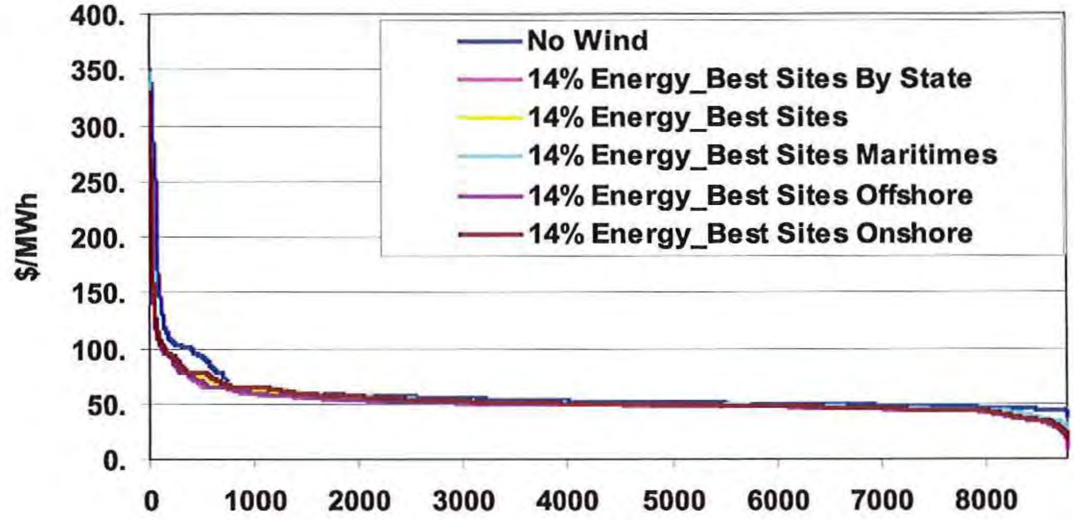
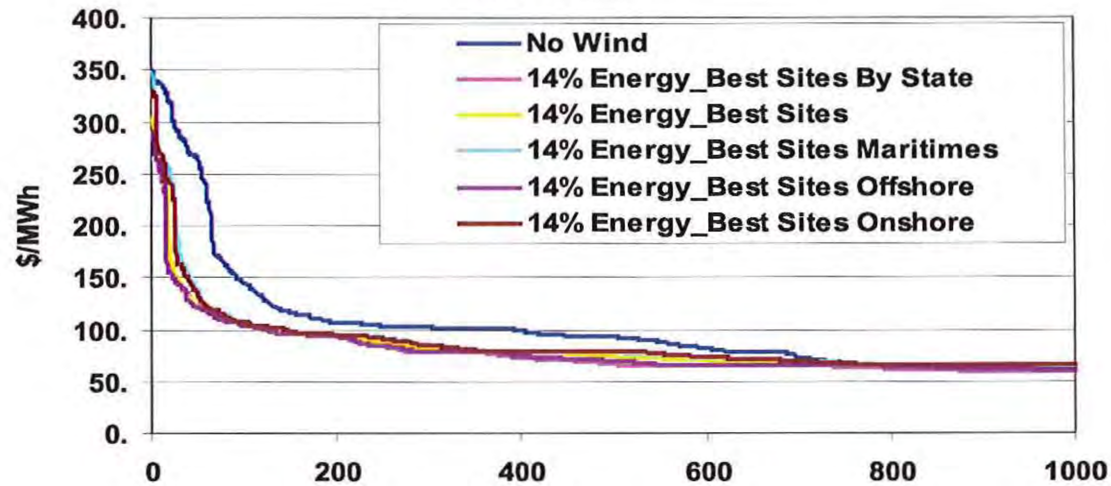


Figure B-3 Annual load weighted average ISO-NE RSP location market price, S-o-A Forecast, 14% penetration No wind, Best Onshore





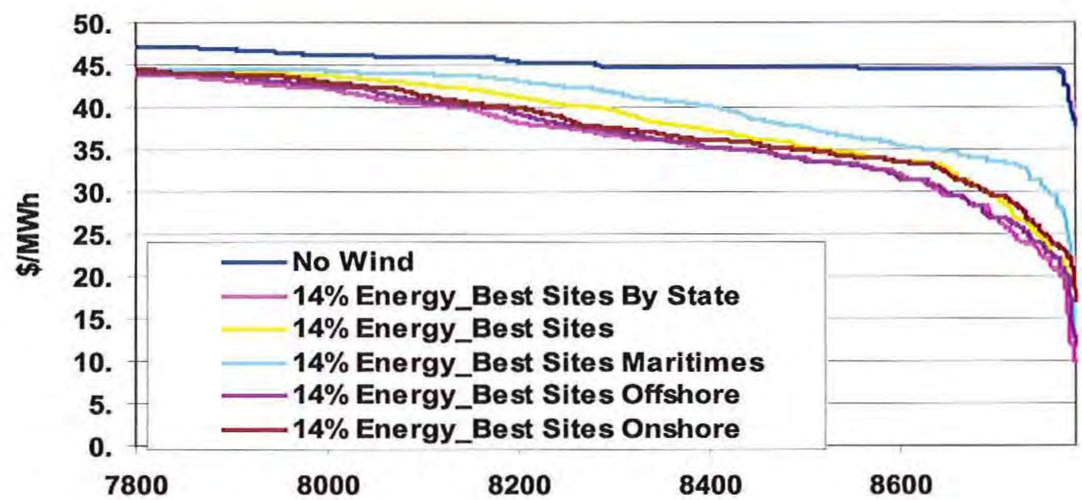


Figure B–4 Annual LMP duration curve, S-O-A Forecast, 14% penetration

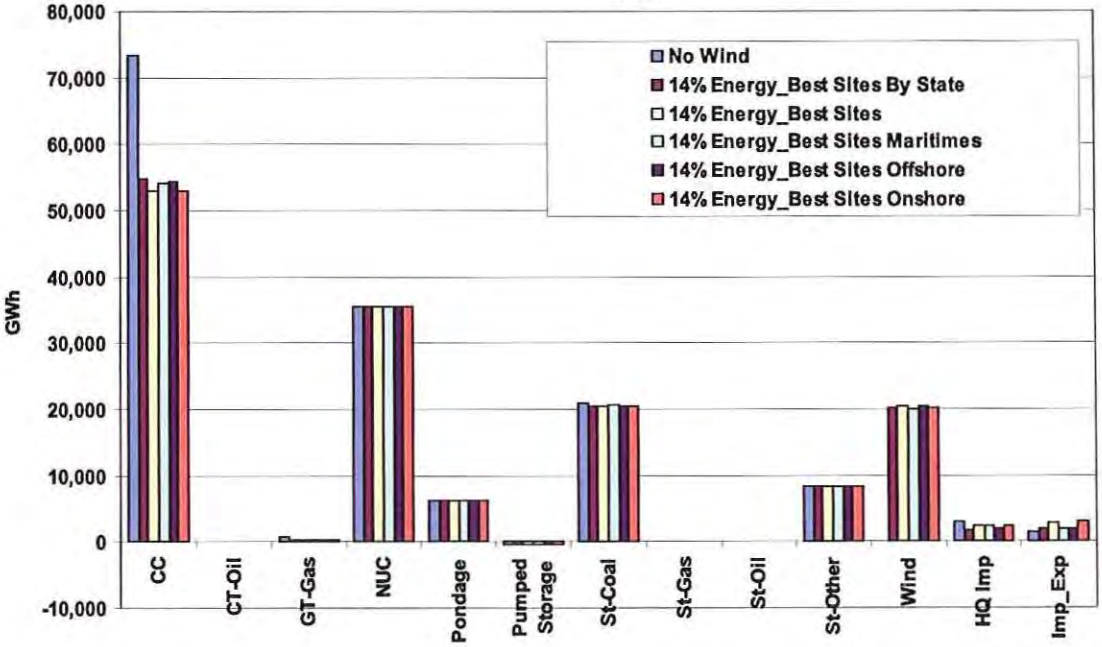


Figure B-5 ISO-NE generation by type, S-o-A forecast, 14% penetration

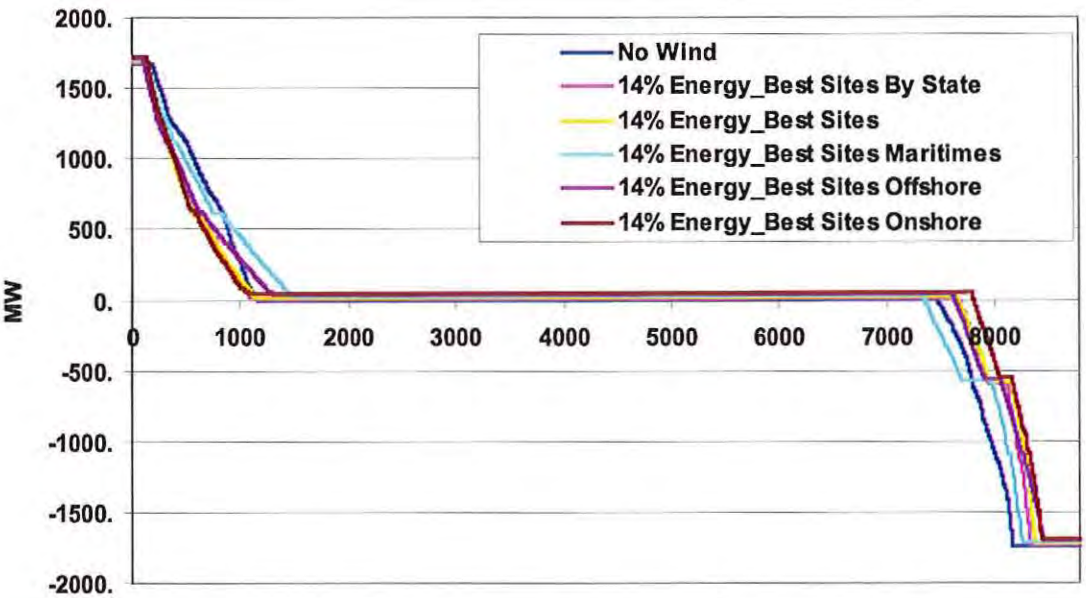


Figure B-6 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, 14% penetration

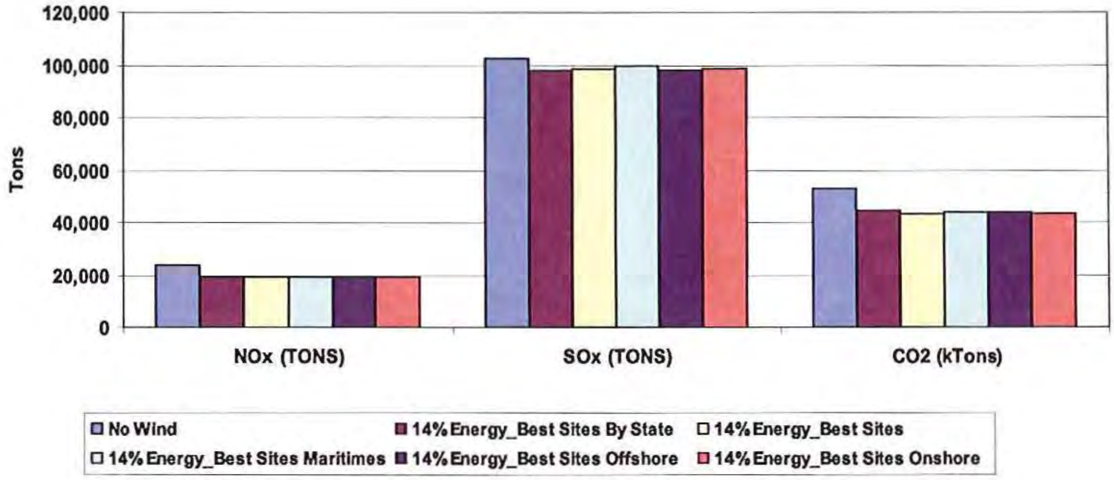
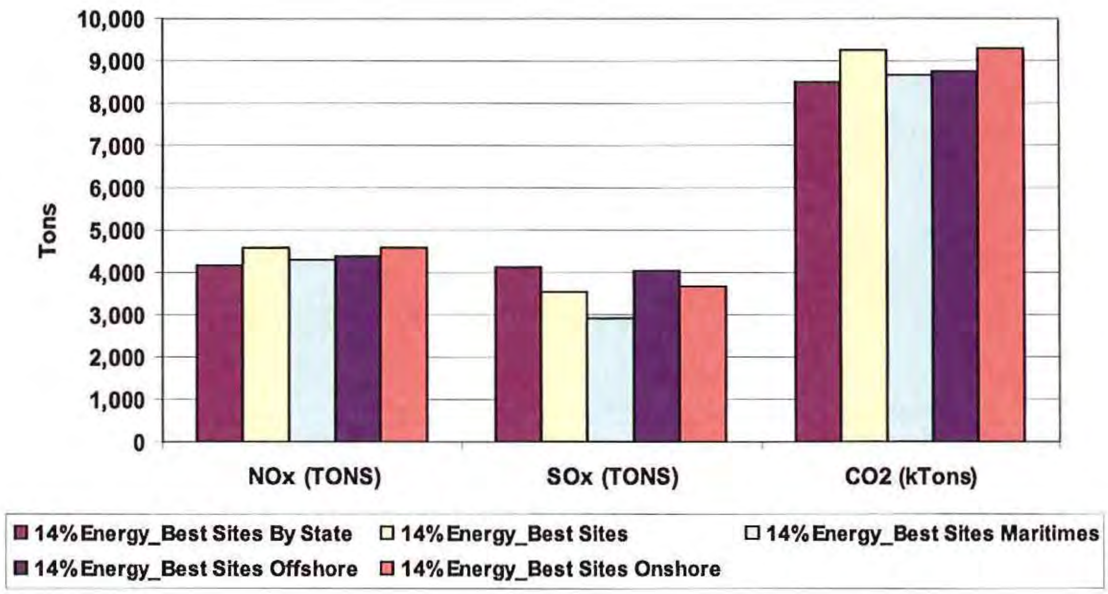


Figure B–7 ISO-NE Total Emissions, S-o-A forecast, 14% penetration



FigureB–8 ISO-NE Total emissions reduction, S-o-A forecast, 14% penetration

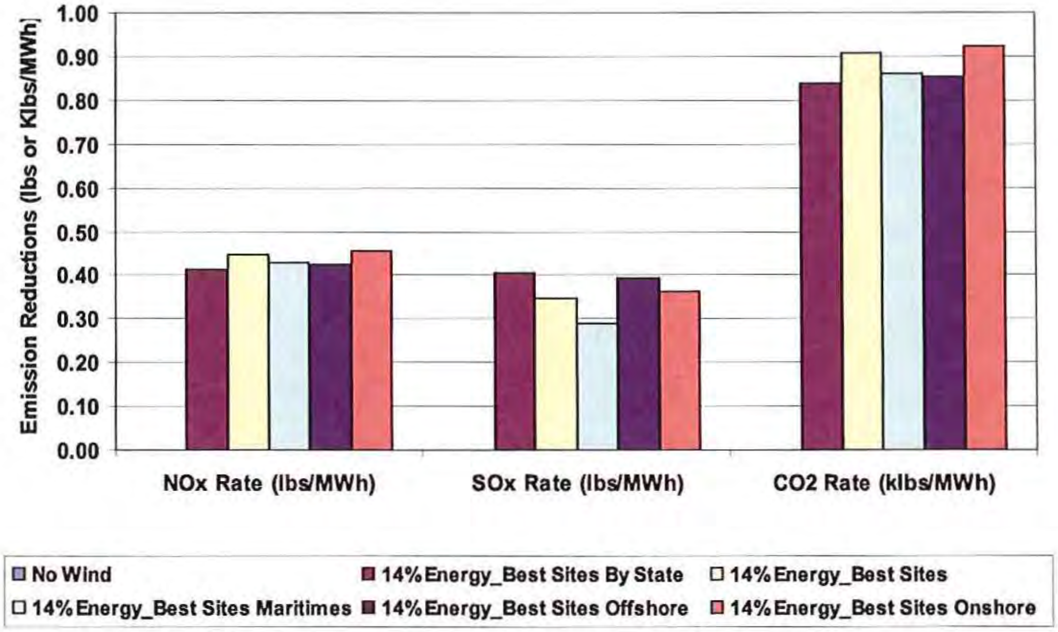


Figure B–9 ISO-NE total emission reduction per MWh of wind generation, S-o-A forecast, 14% penetration

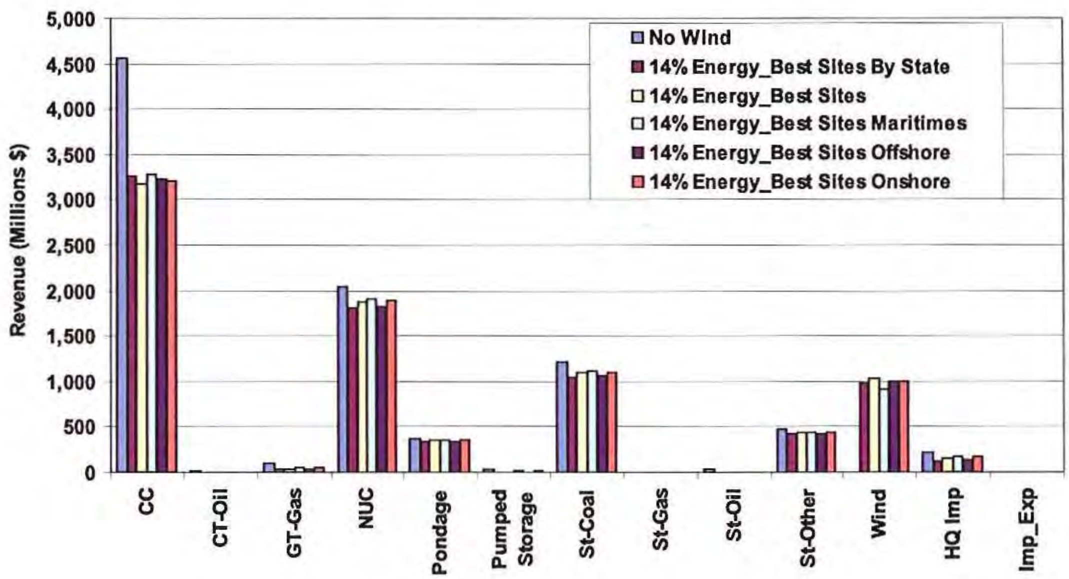


Figure B–10 ISO-NE revenue by type, S-o-A forecast, 14% penetration

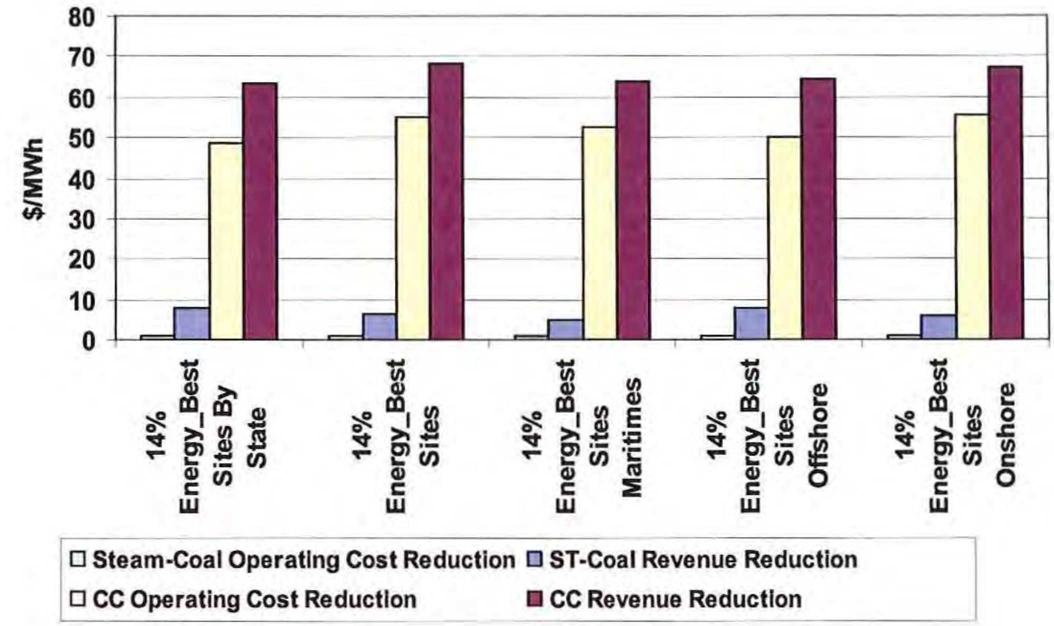


Figure B–11 ISO-NE CC and St-coal revenue and operating cost reduction per MWh of wind generation, S-o-A forecast, 14% penetration

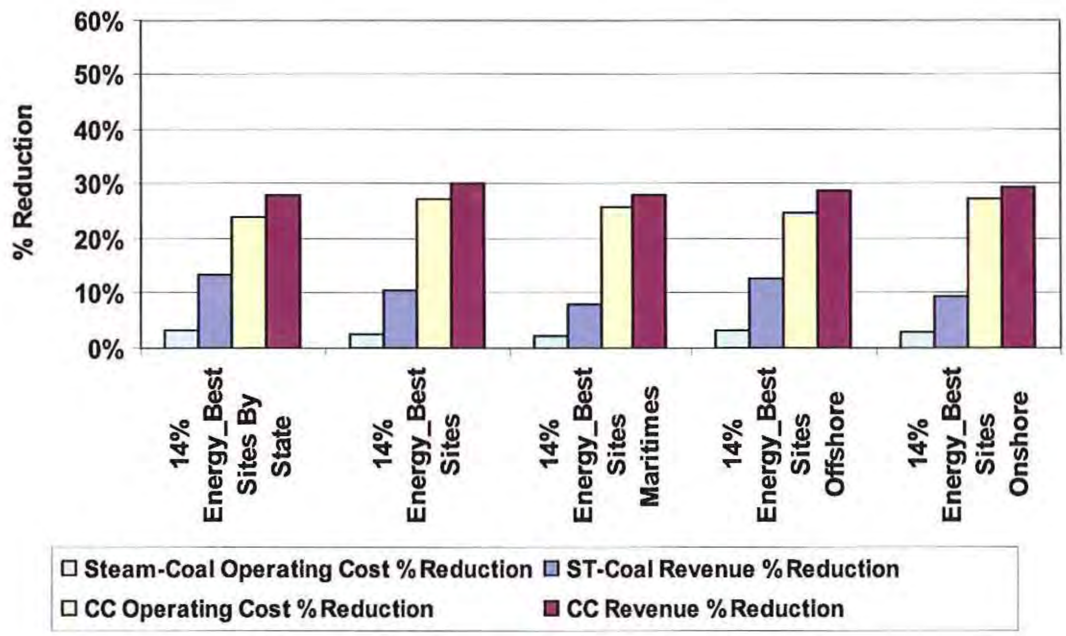


Figure B–12 ISO-NE CC and St-coal revenue and operating cost percent reduction per MWh of wind generation, S-o-A forecast, 14% penetration

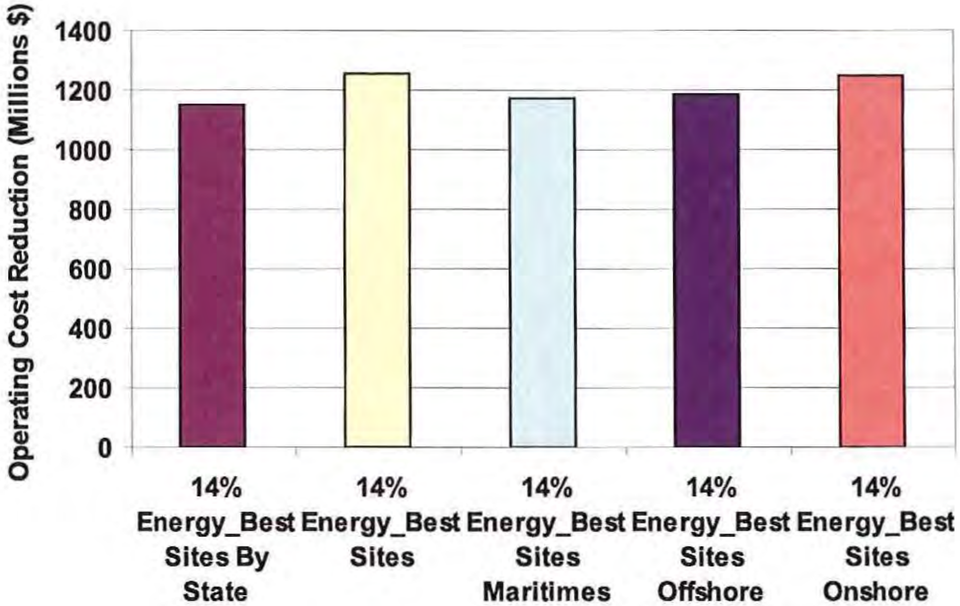


Figure B–13 ISO-NE operating Cost reduction, S-o-A forecast, 14% penetration

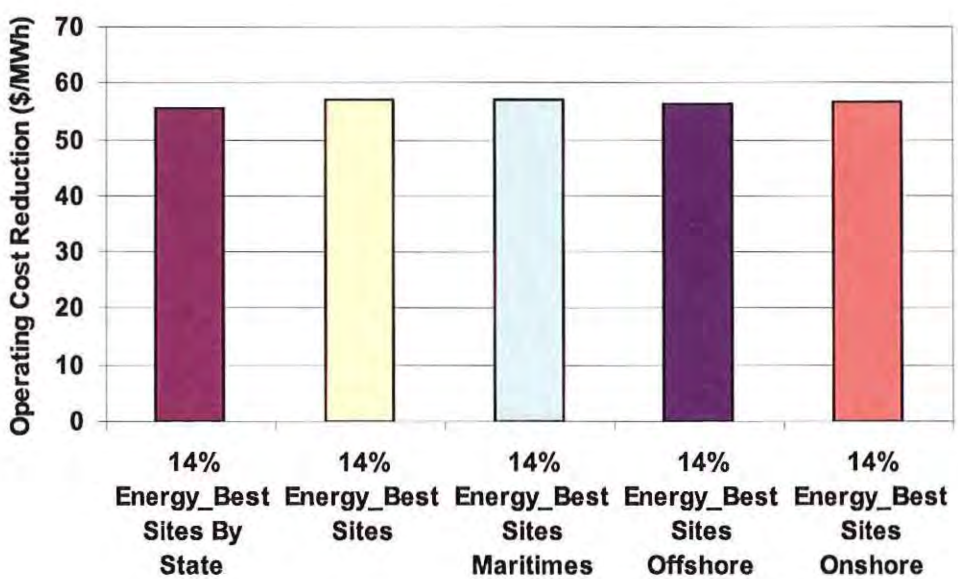


Figure B–14 ISO-NE operating cost reduction per MWh of wind generation, S-o-A forecast, 14% penetration

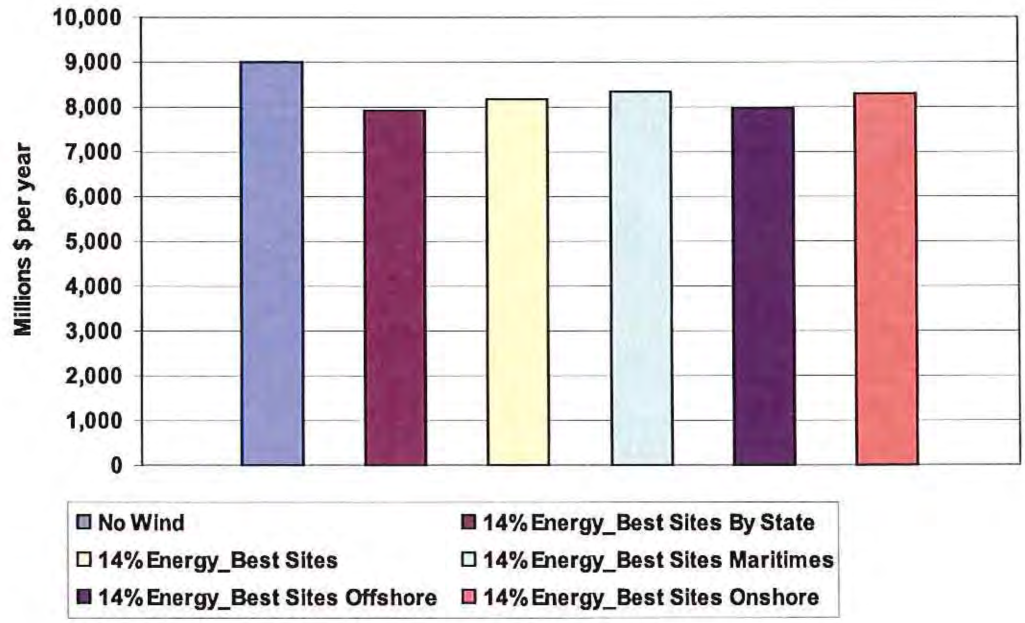


Figure B–15 ISO-NE wholesale load payments for energy, S-o-A forecast, 14% penetration

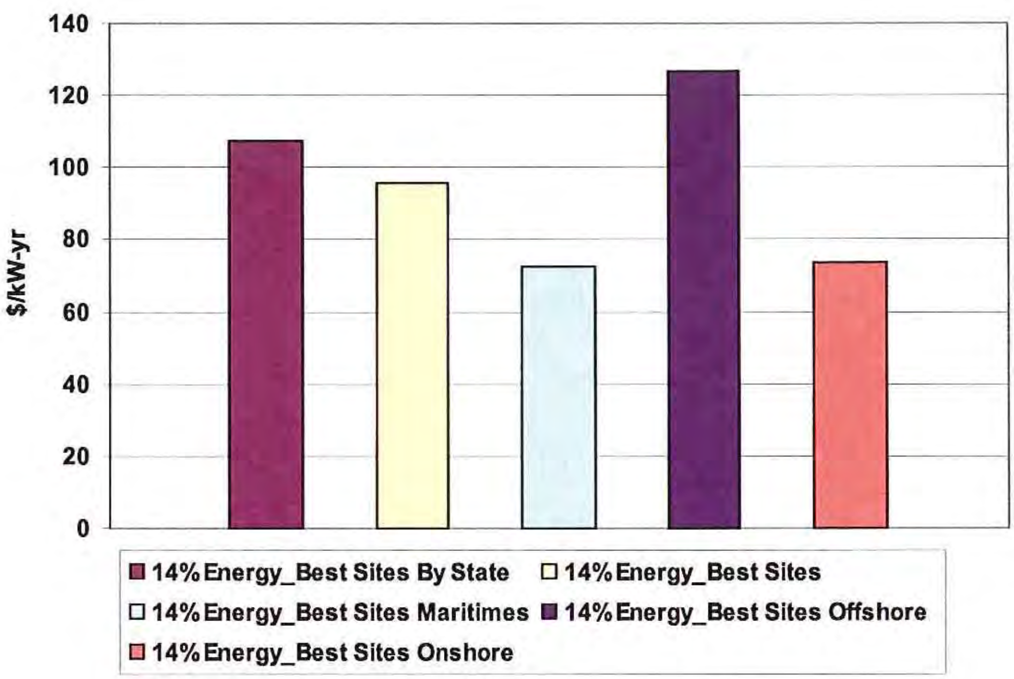


Figure B–16 ISO-NE wholesale load payment for energy reduction per kW of wind, S-o-A forecast, 14% penetration

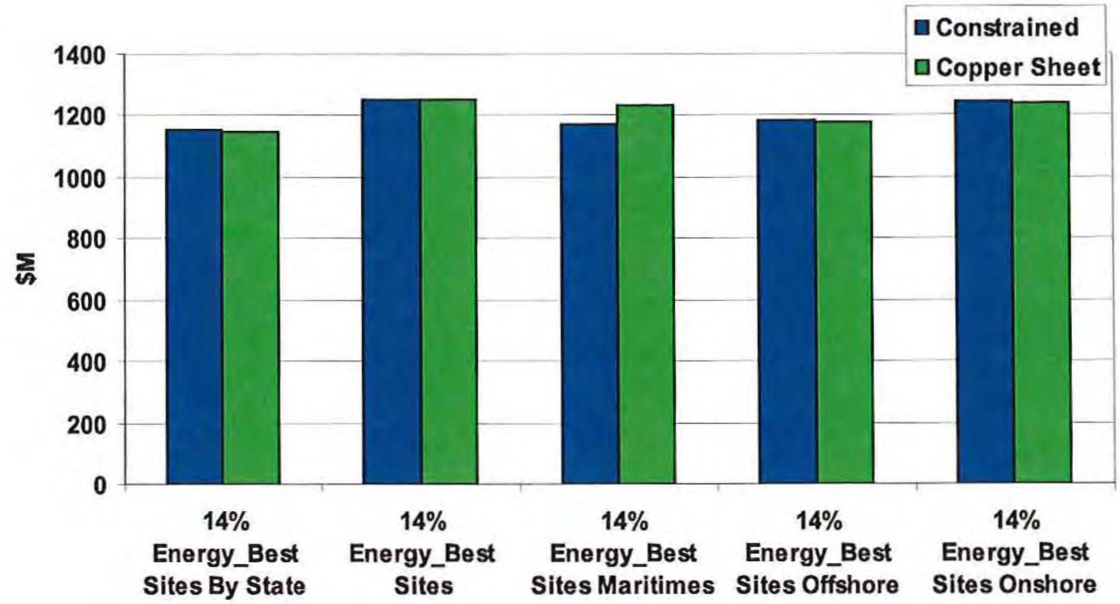


Figure B–17 Impact of transmission on ISO-NE Operating cost reduction, S-o-A forecast, 14% penetration

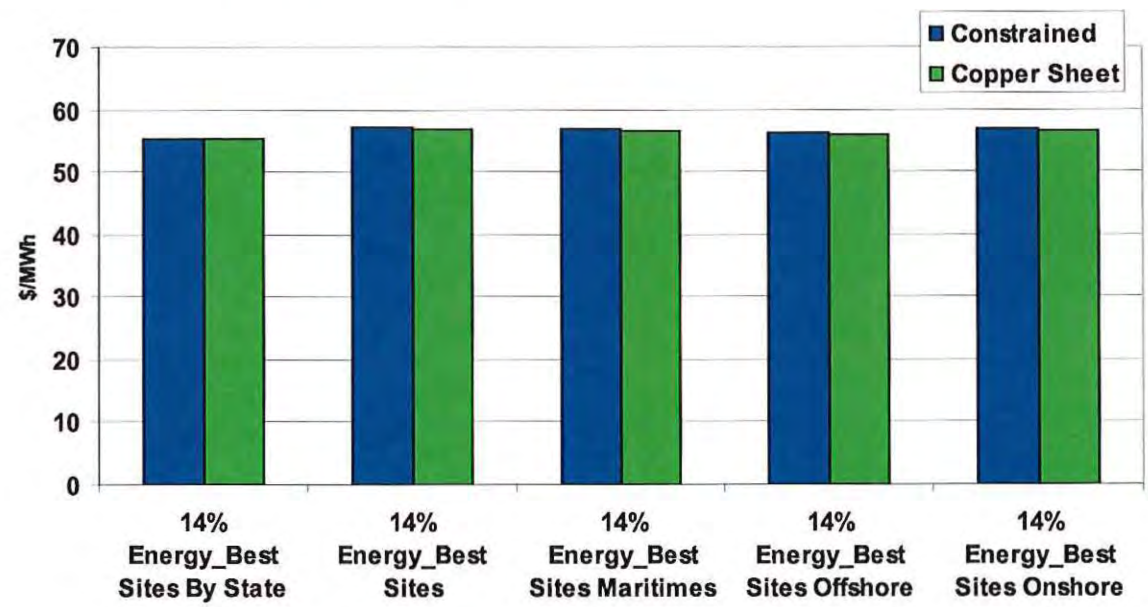


Figure B–18 Impact of transmission on ISO-NE operating cost reduction per MWh of Wind generation, S-o-A forecast, 14% penetration

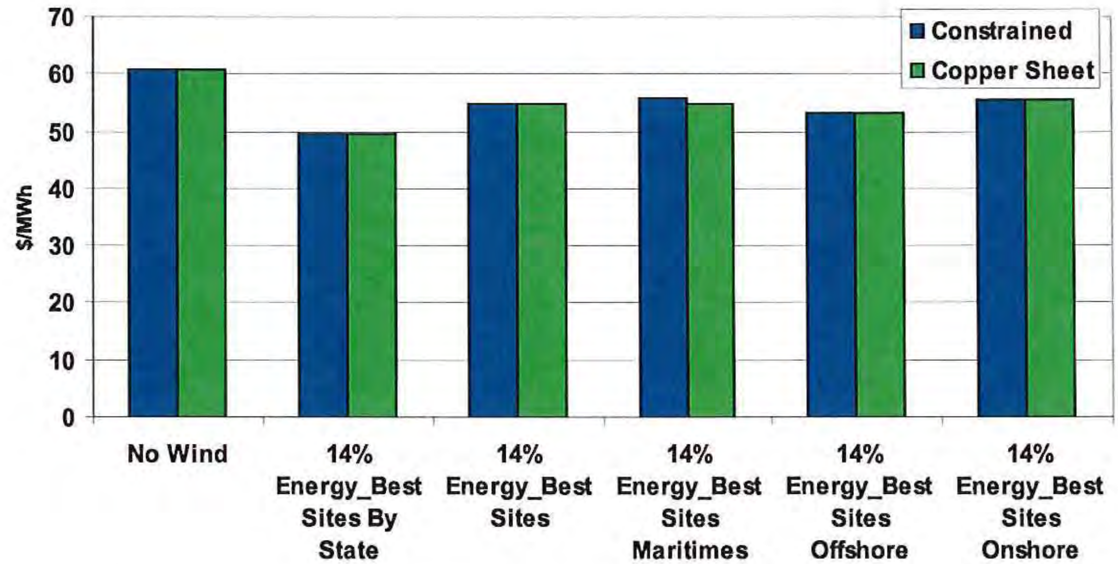


Figure B–19 Impact of transmission on ISO-NE Load Weighted Average LMP, S-o-A forecast, 14% penetration

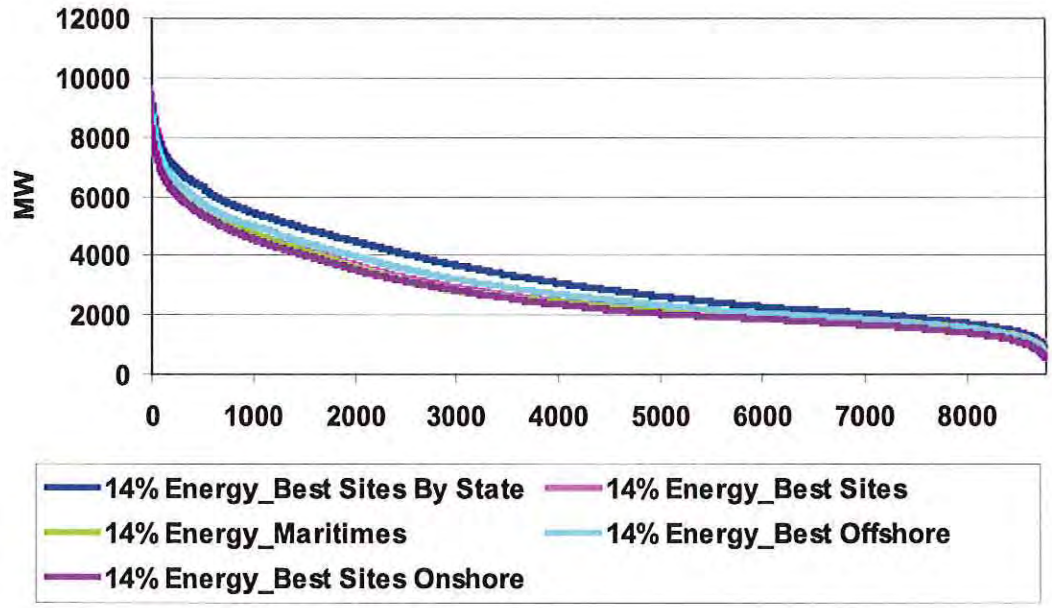


Figure B–20 Hourly range up capability, S-o-A forecast, 14% penetration

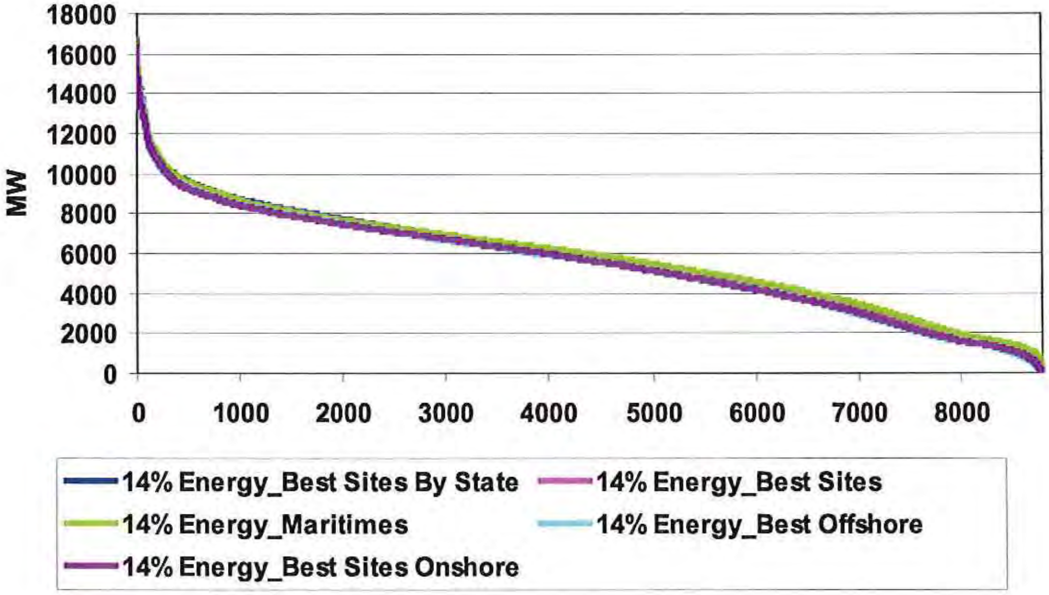


Figure B–21 Hourly range down capability, S-o-A forecast, 14% penetration

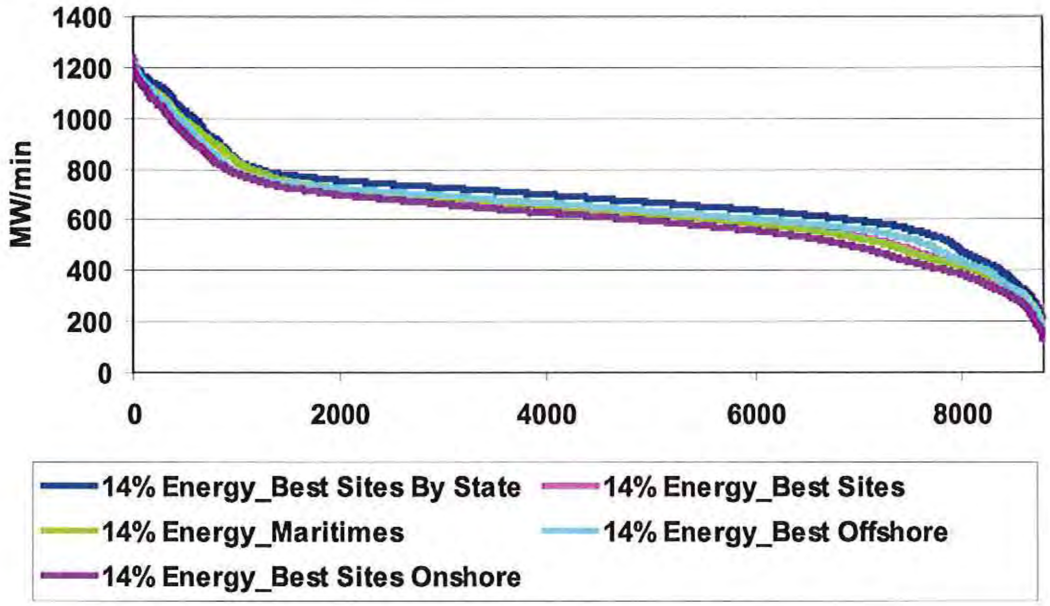


Figure B–22 Hourly ramp up MW/min capability, S-o-A forecast, 14% penetration

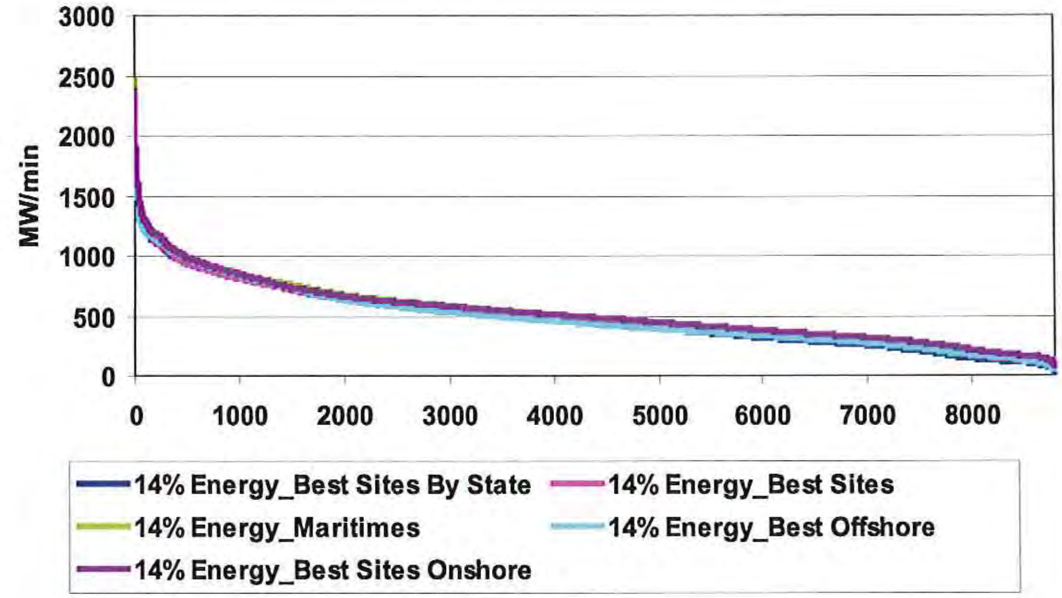
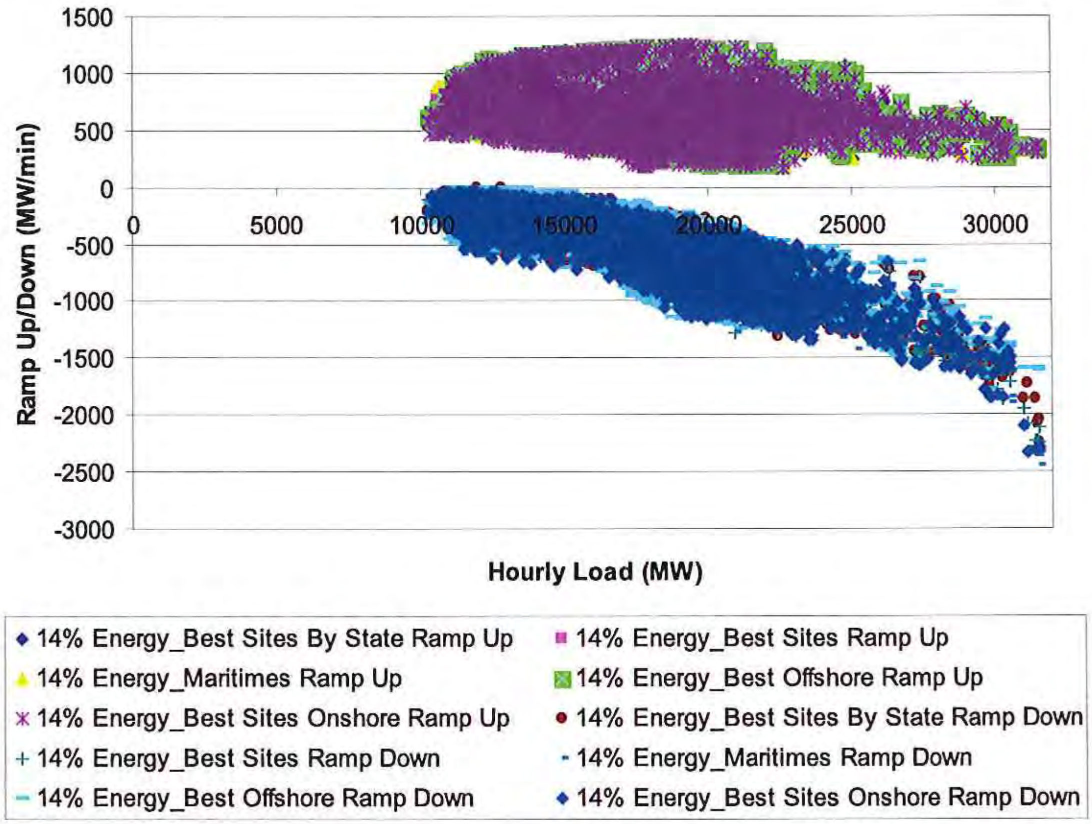


Figure B–23 Hourly ramp down MW/min capability, S-o-A forecast, 14% penetration



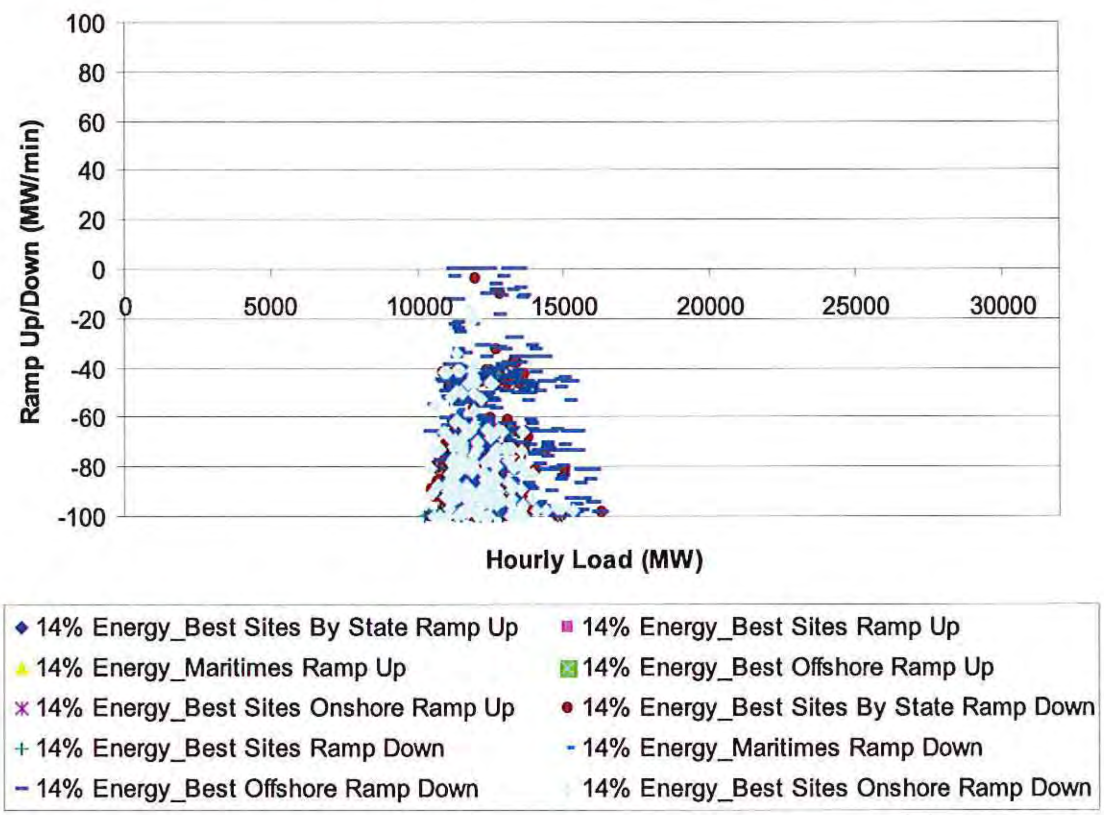


Figure B-24 Hourly Ramp Up/Down vs. Load, S-o-A forecast,14% Energy

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

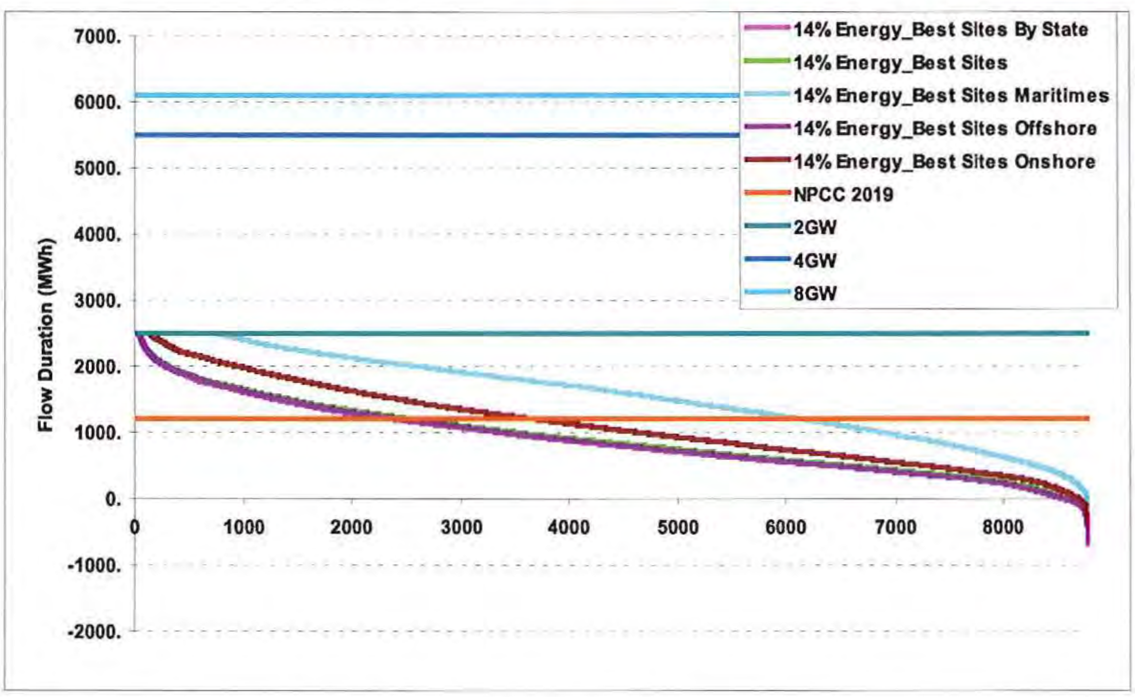


Figure B–25 Orrington South interface flow, S-o-A forecast, 14% penetration

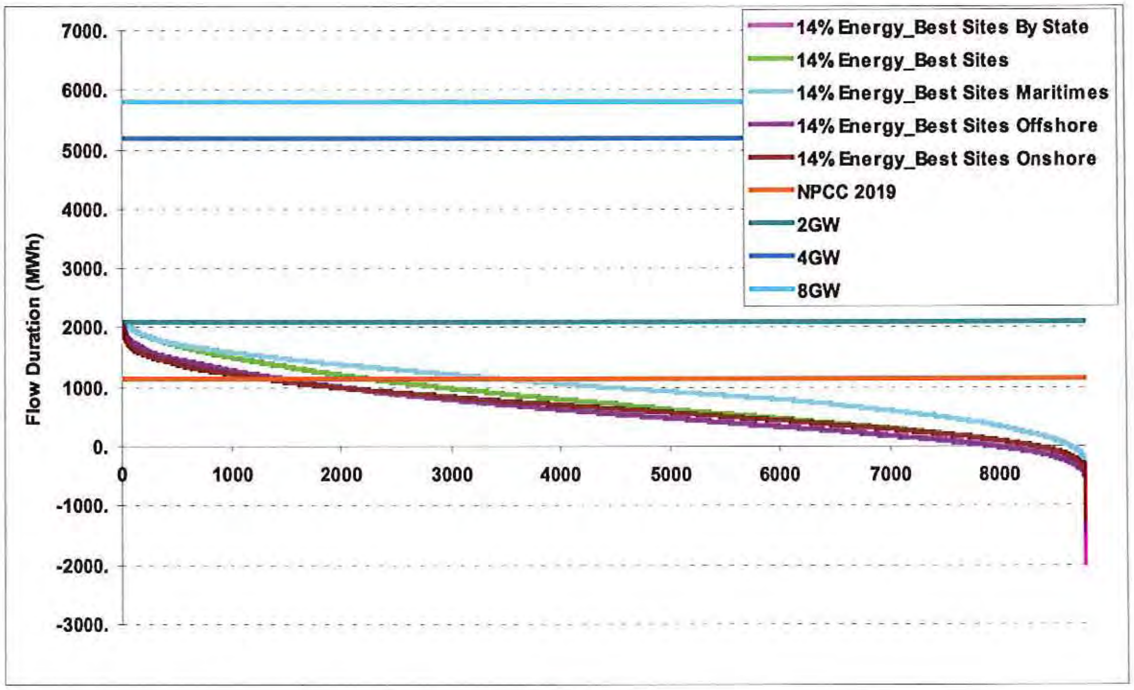


Figure B–26 Surowiec South interface flow, S-o-A forecast, 14% penetration

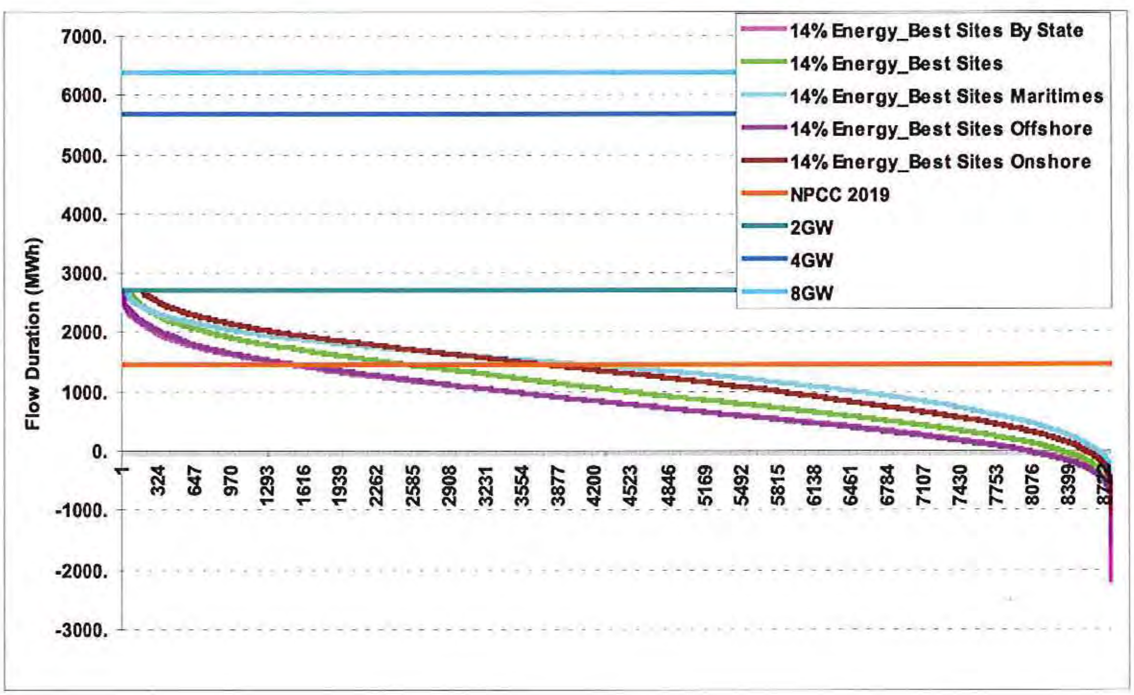


Figure B–27 Maine/New Hampshire interface flow, S-o-A forecast, 14% penetration

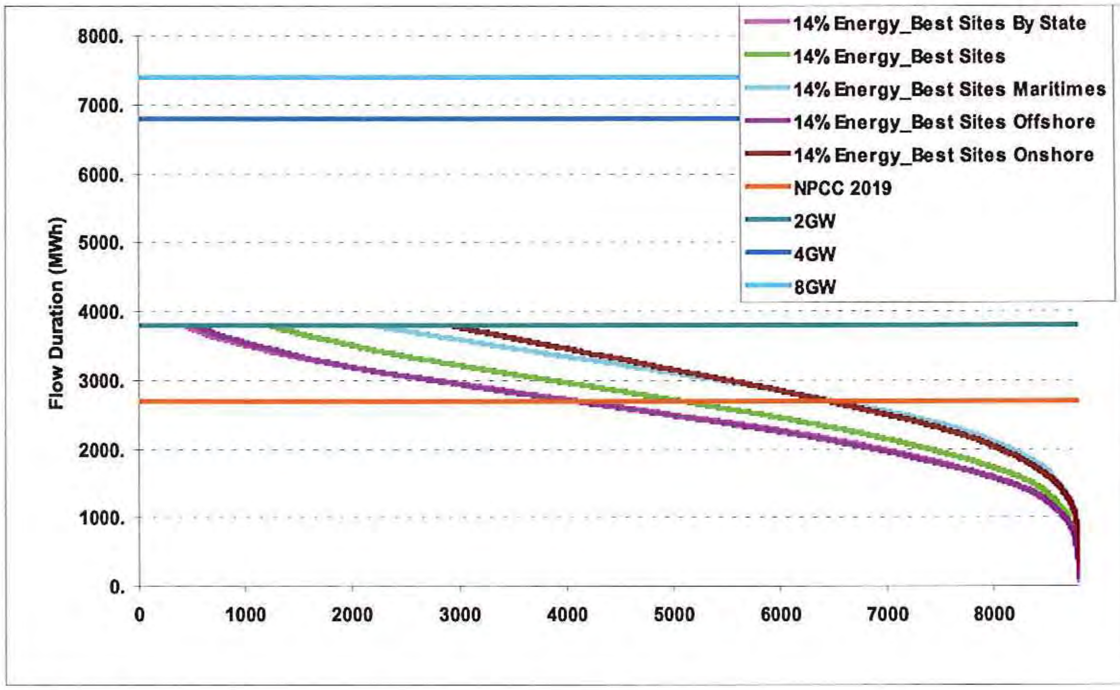


Figure B–28 North /South interface flow, S-o-A forecast, 14% penetration

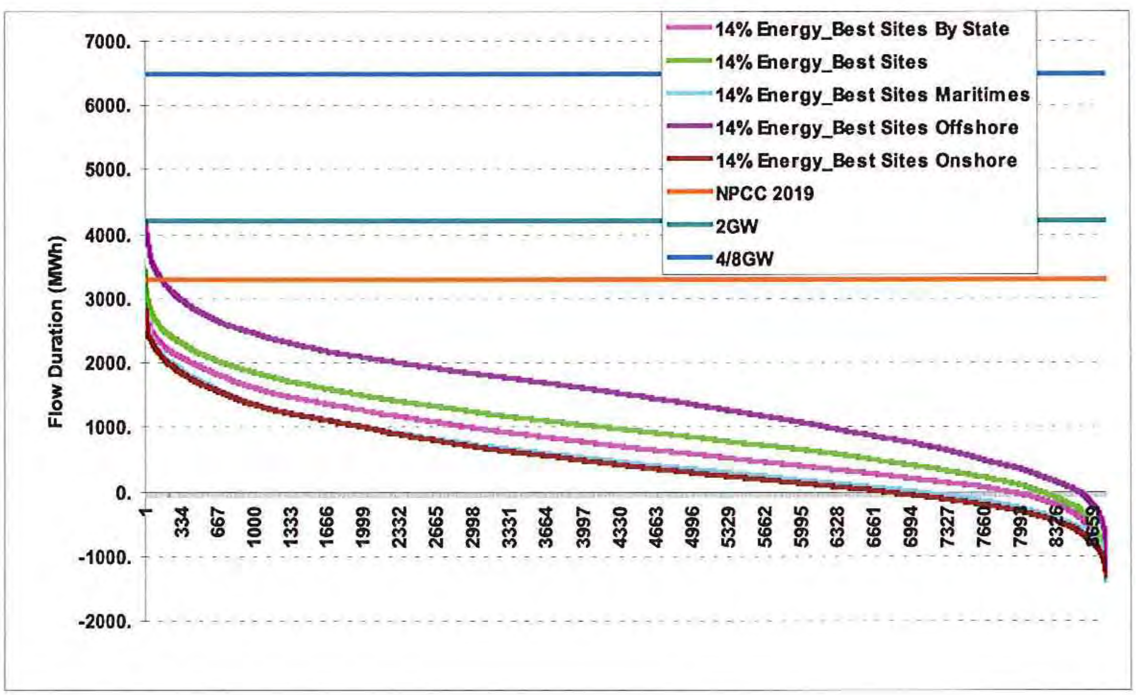


Figure B–29 SEMA/RI Export interface flow, S-o-A forecast, 14% penetration

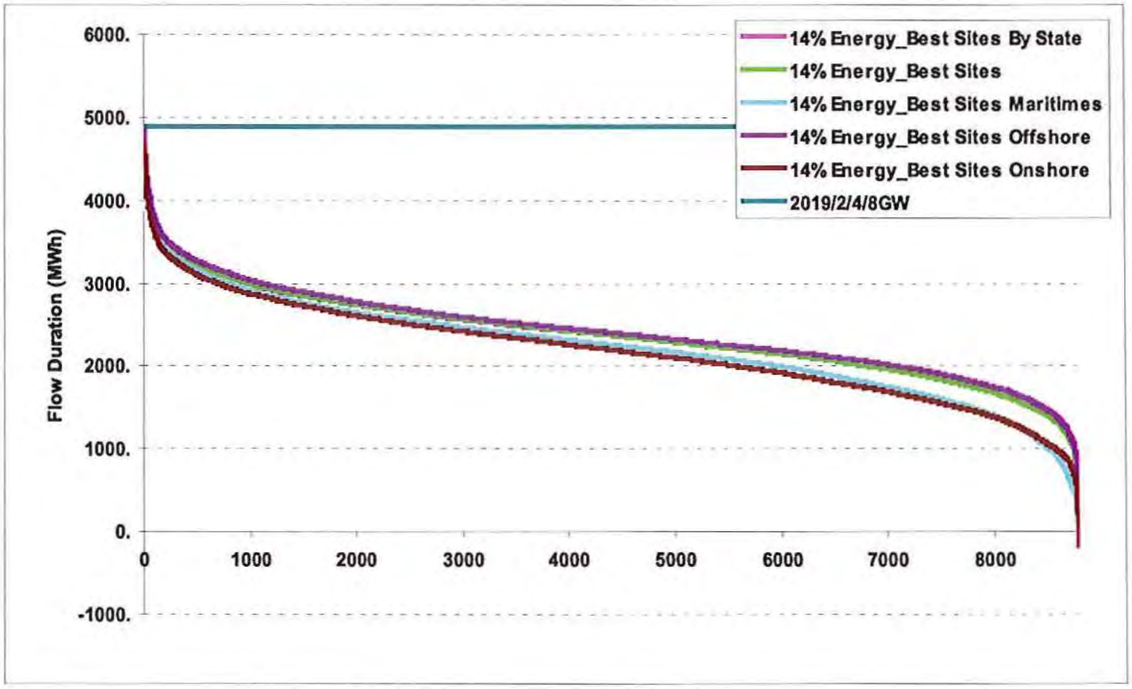


Figure B–30 Boston Import, S-o-A forecast interface flow, 14% penetration

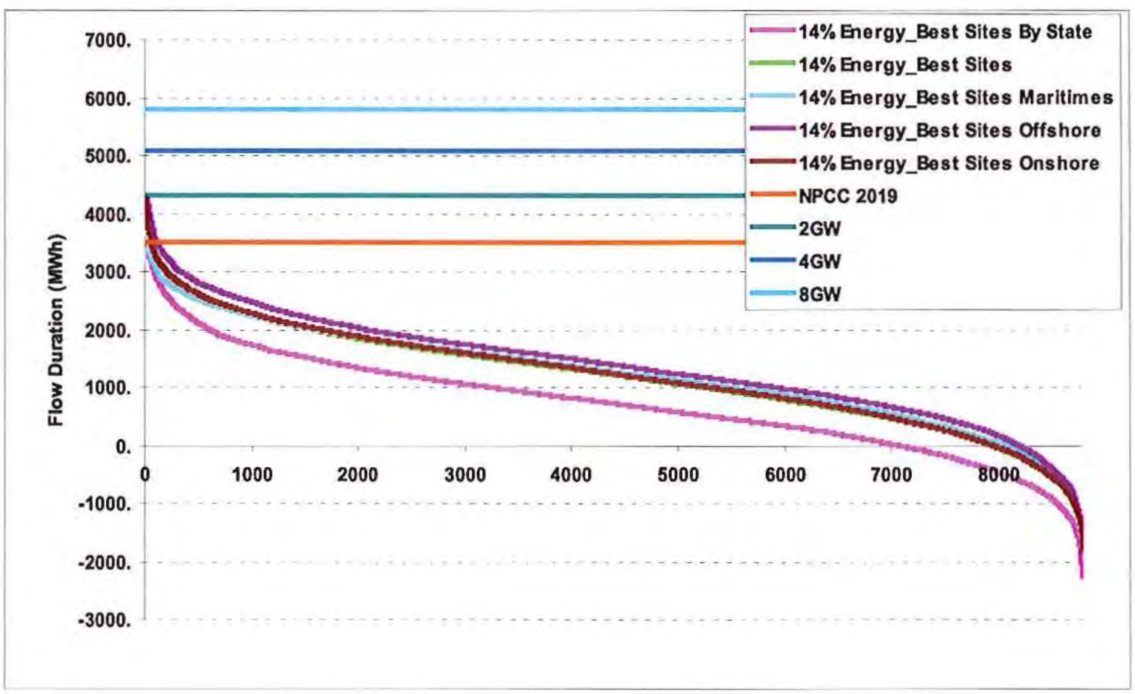


Figure B–31 East-West interface flow, S-o-A forecast, 14% penetration

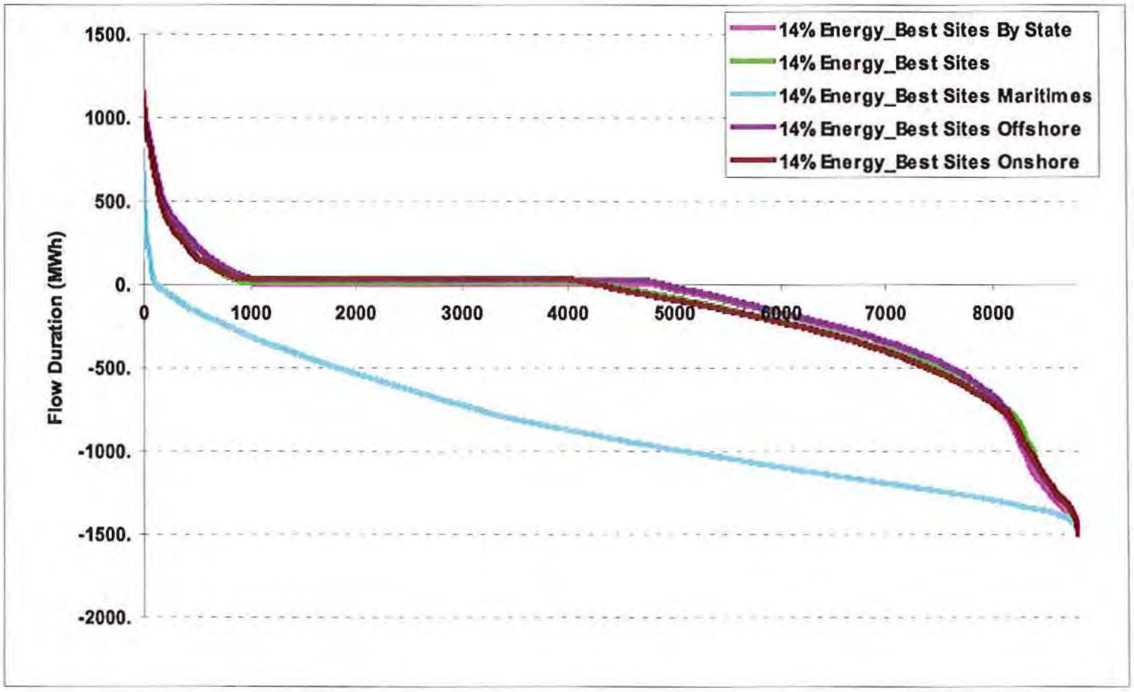


Figure B–32 ISO-NE to NB interface flow, S-o-A forecast, 14% penetration

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.

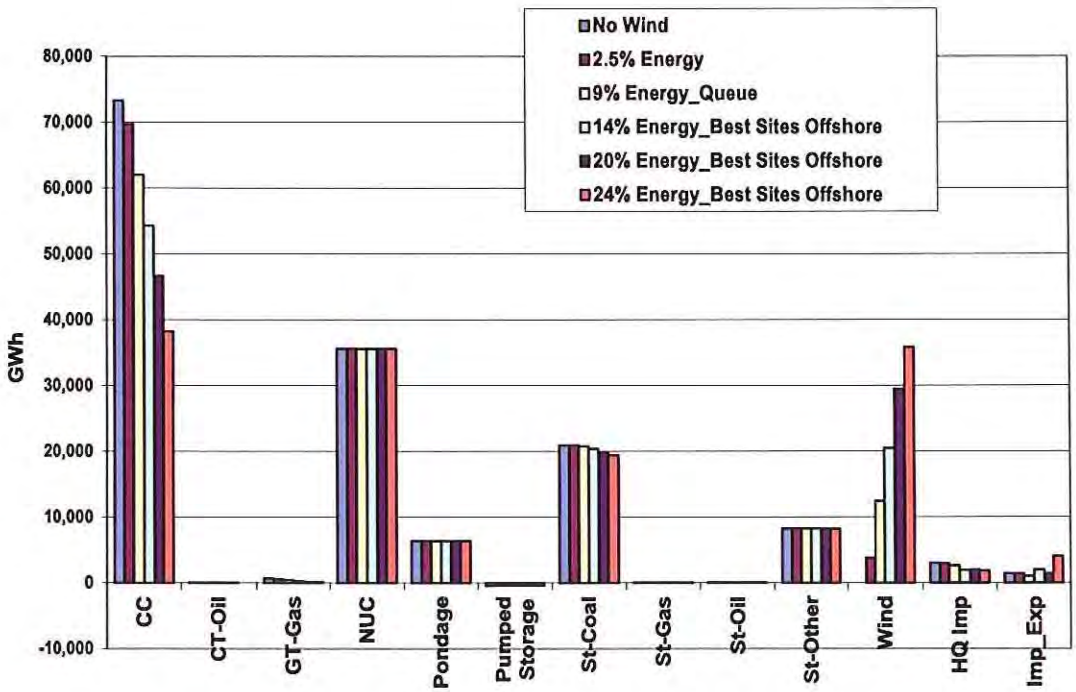


Figure B–33 ISO-NE generation by type, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

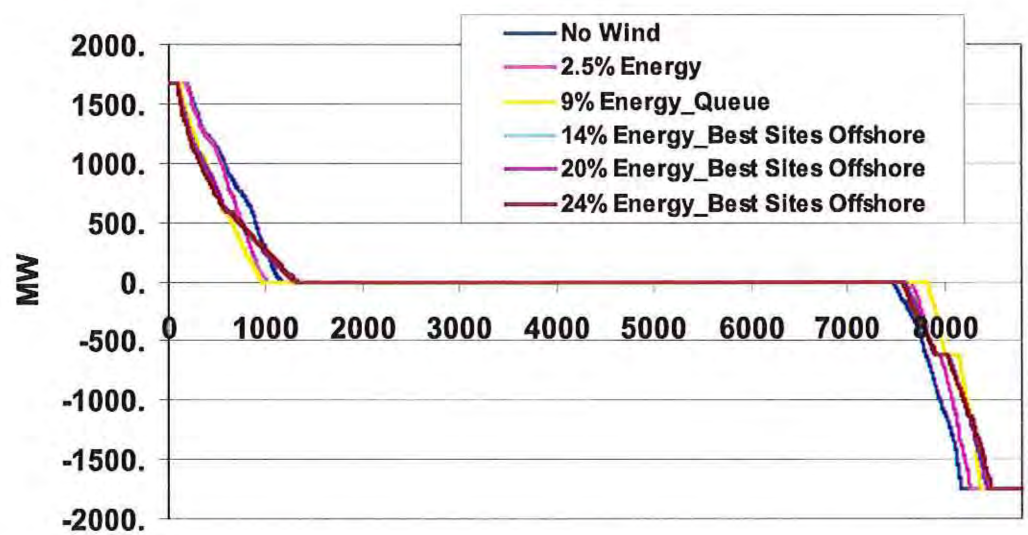


Figure B–34 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

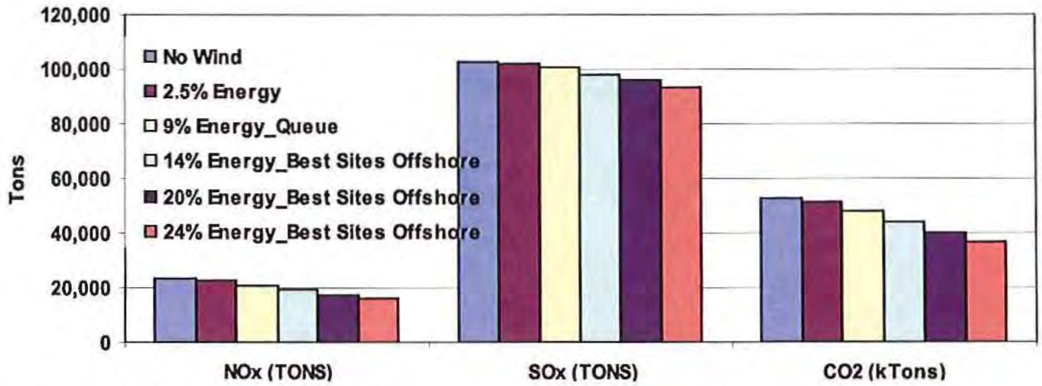


Figure B-35 ISO-NE Total Emissions, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

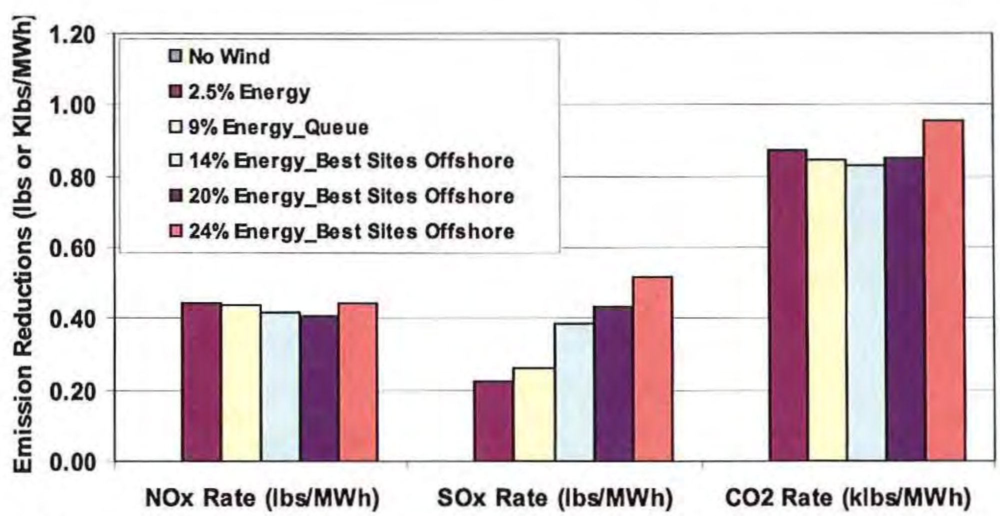


Figure B-36 ISO-NE total emission reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

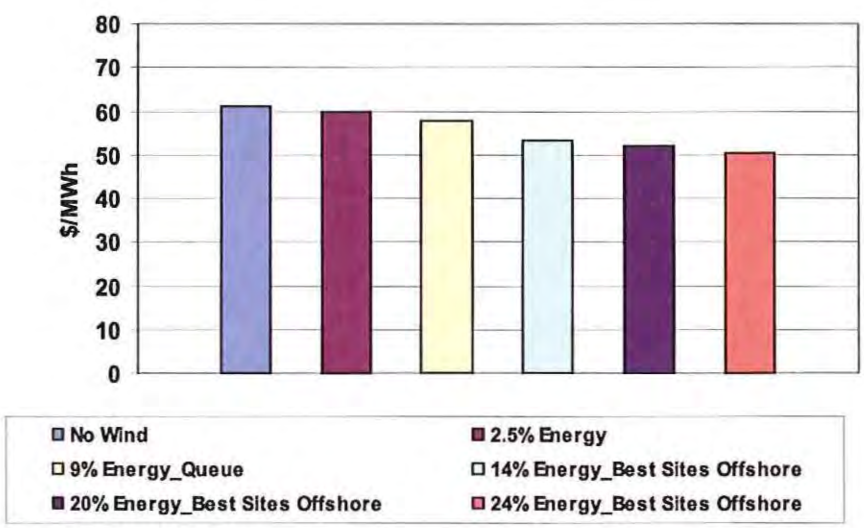


Figure B-37 Annual load weighted average ISO-NE location market price, S-O-A Forecast, Best Sites Offshore, S-o-A Forecast

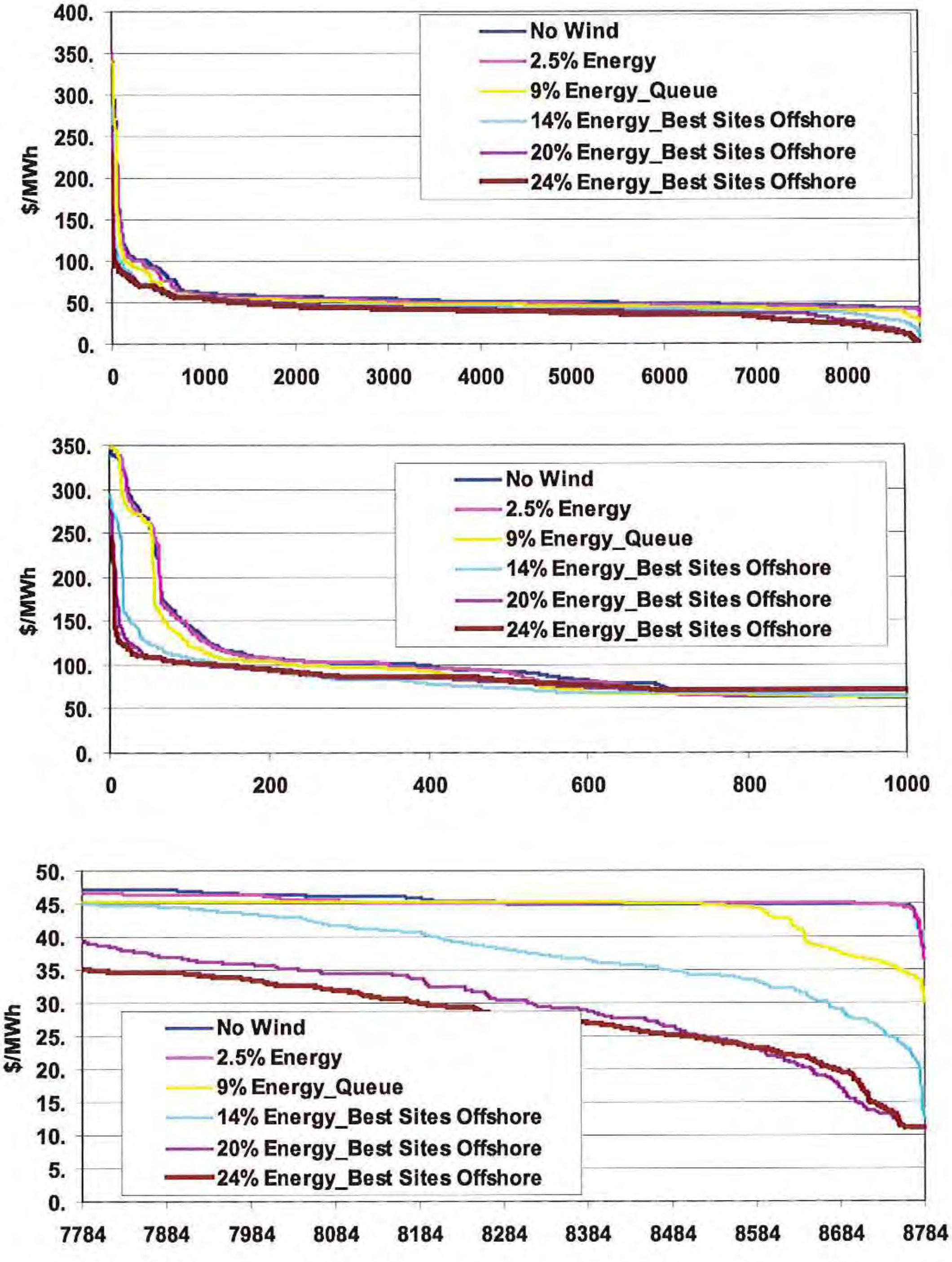


Figure B–38 **Annual LMP duration curve, S-O-A Forecast, Best Sites Offshore, S-o-A Forecast**

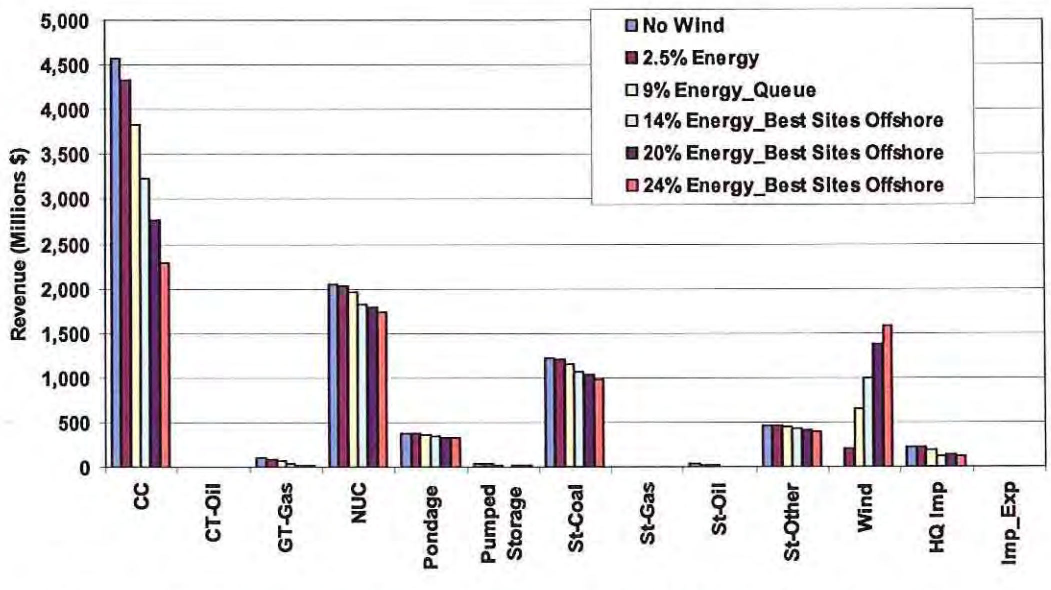


Figure B–39 ISO-NE revenue by type, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

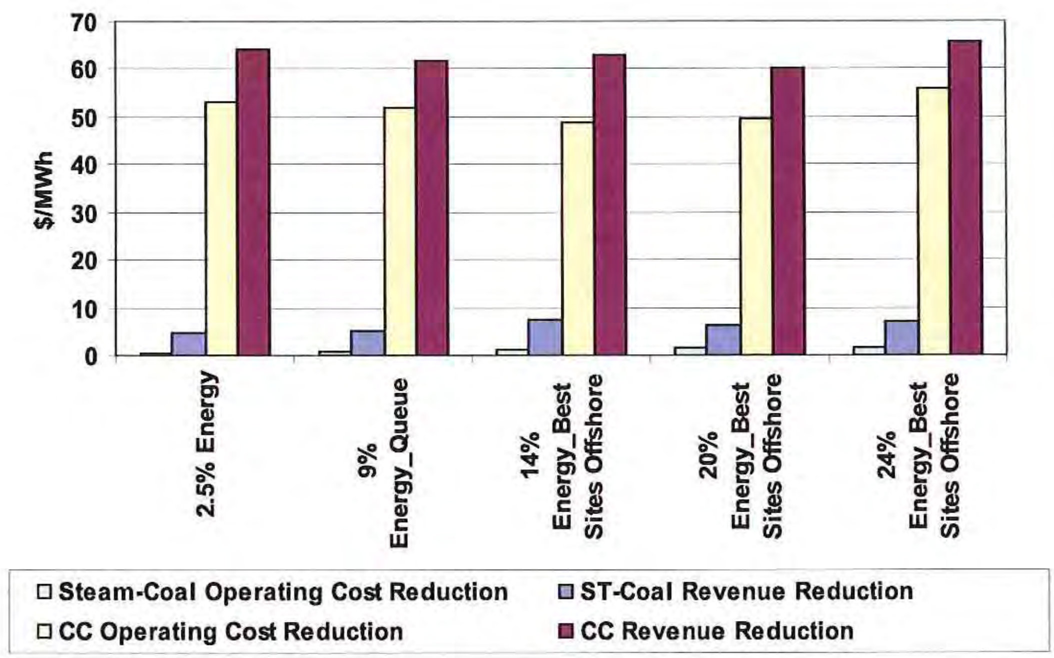


Figure B–40 ISO-NE CC and St-coal revenue and operating cost reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

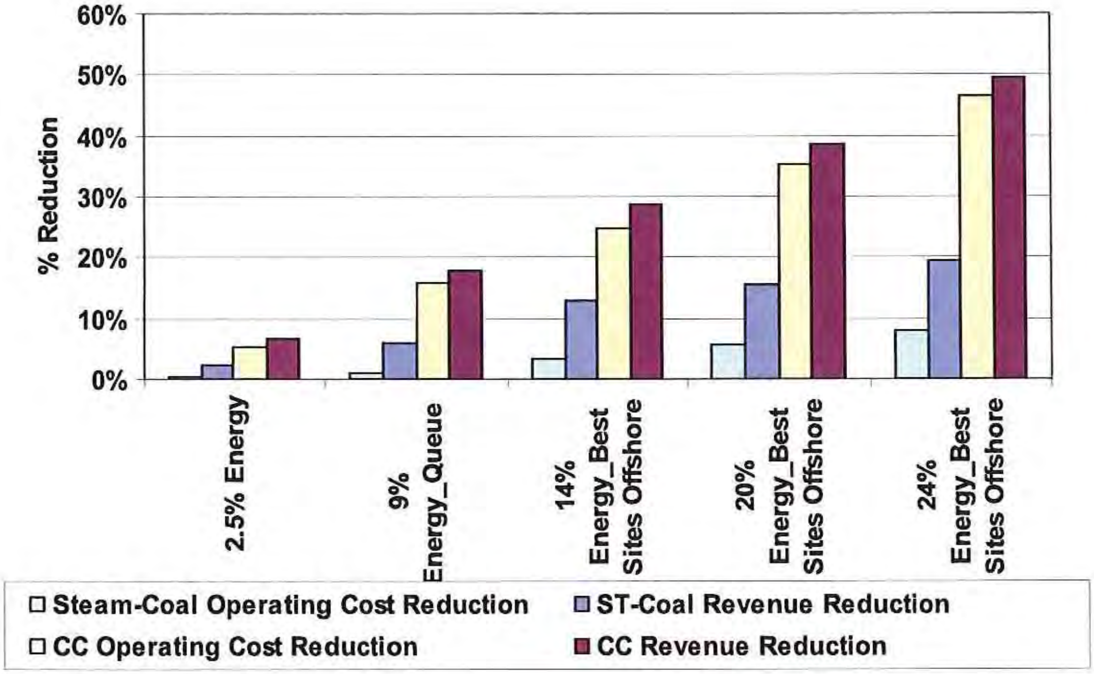


Figure B–41 ISO-NE CC and St-coal revenue and operating cost percent reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

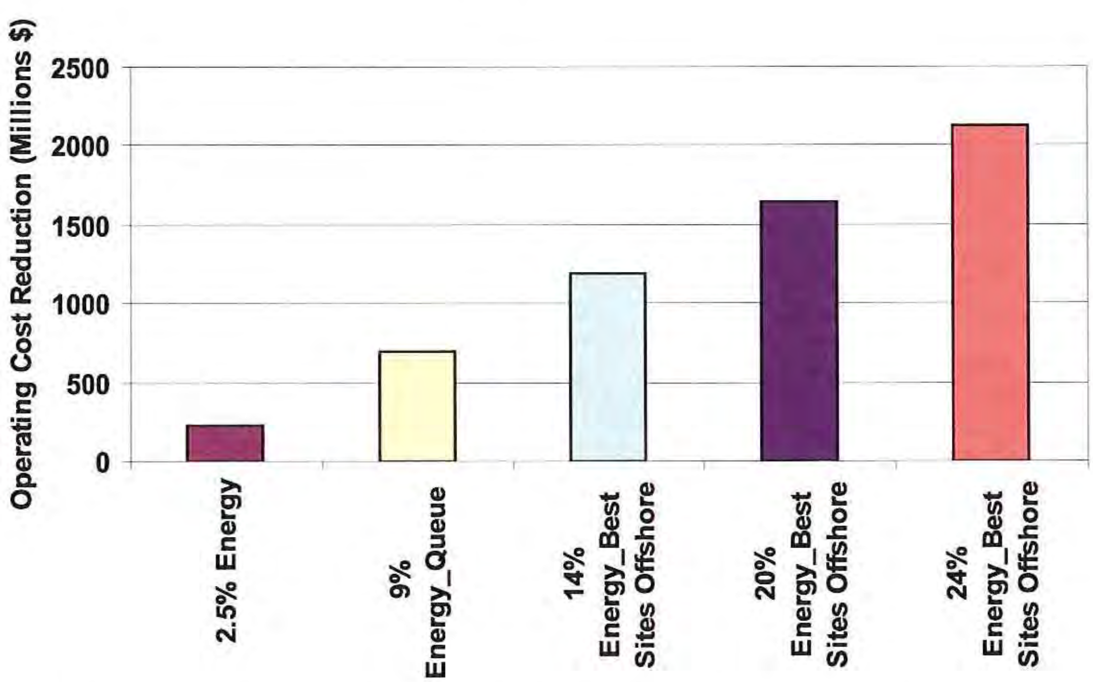


Figure B–42 ISO-NE operating Cost reduction, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

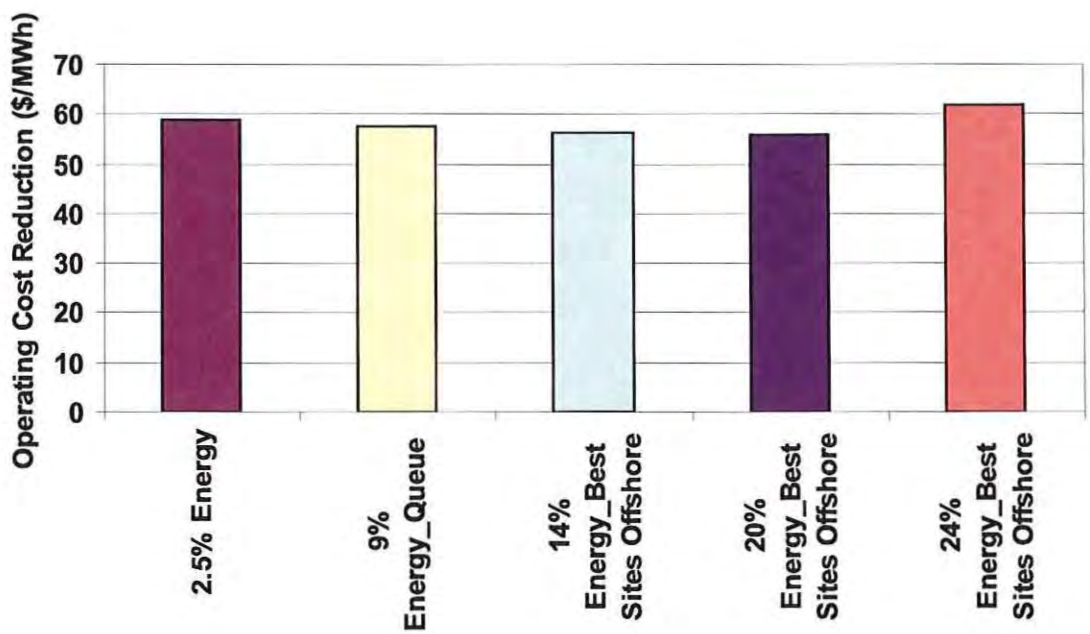


Figure B–43 ISO-NE operating cost reduction per MWh of wind generation, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

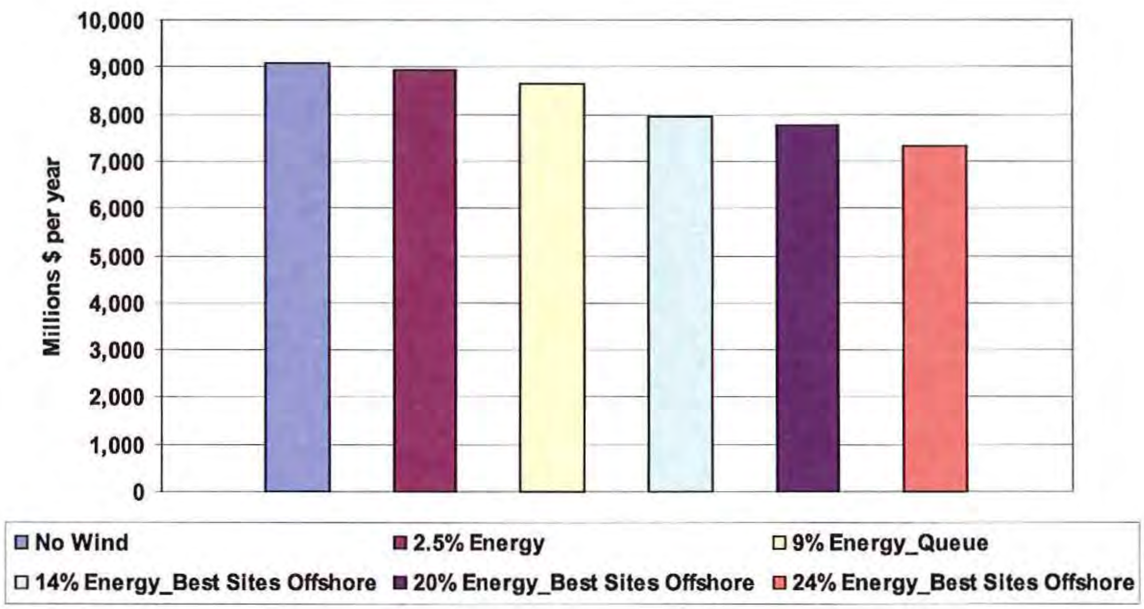


Figure B–44 ISO-NE wholesale load payments for energy, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

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

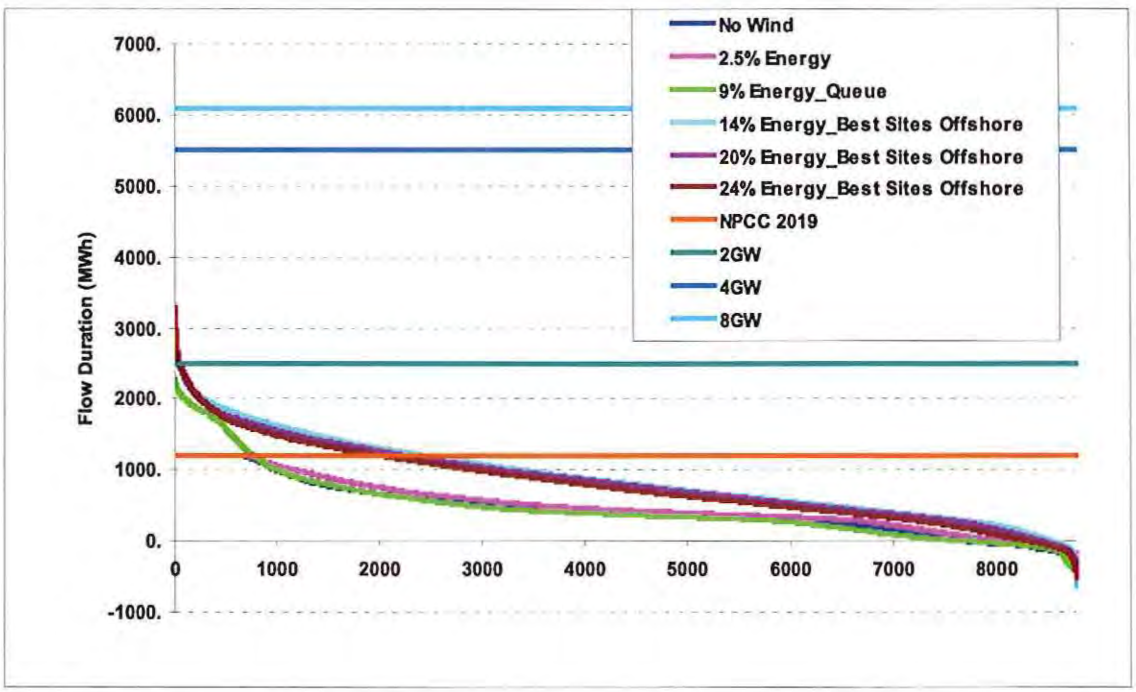


Figure B–45 Orrington South interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

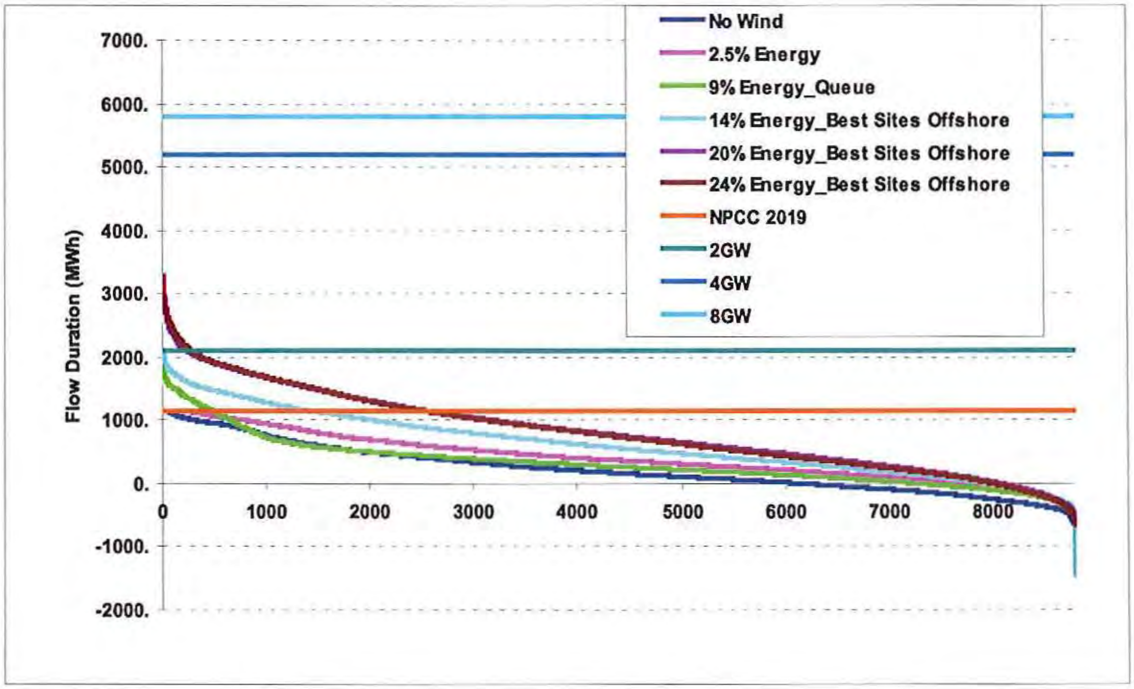


Figure B–46 Surowiec South interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

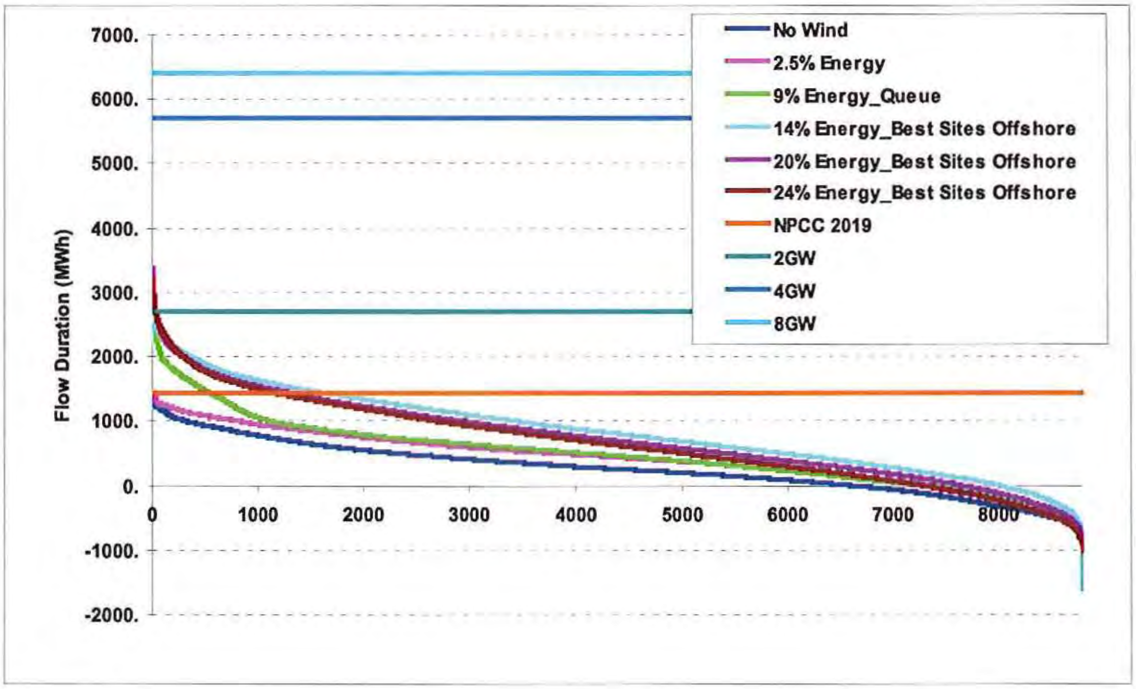


Figure B–47 Maine/New Hampshire interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

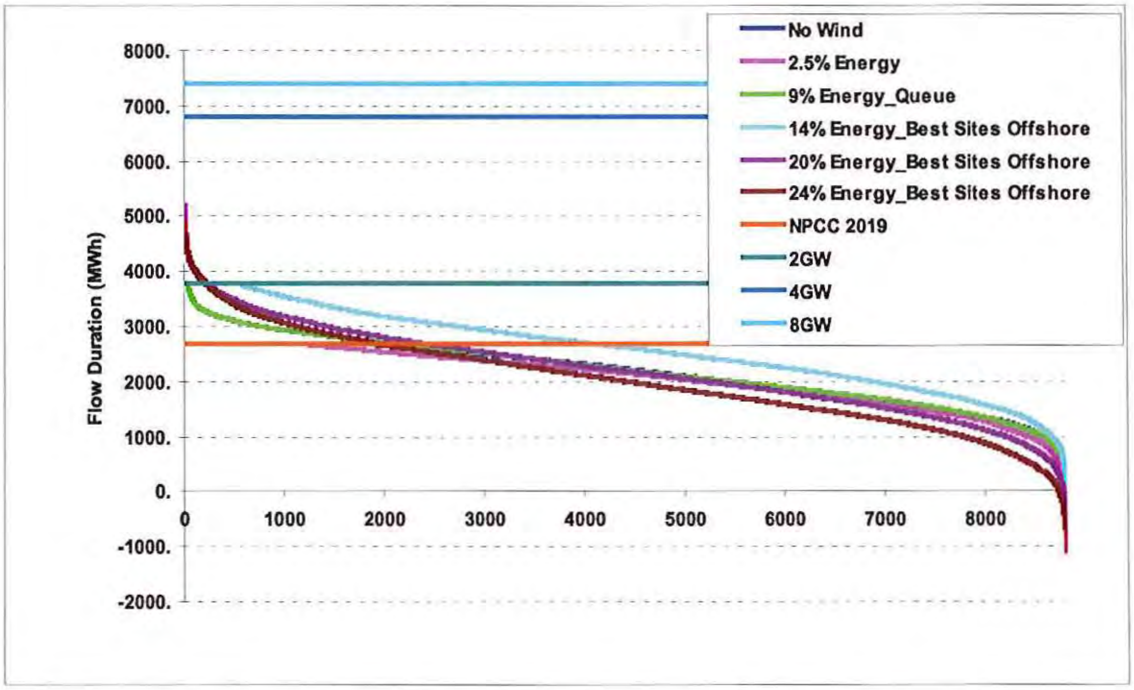


Figure B–48 North /South interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

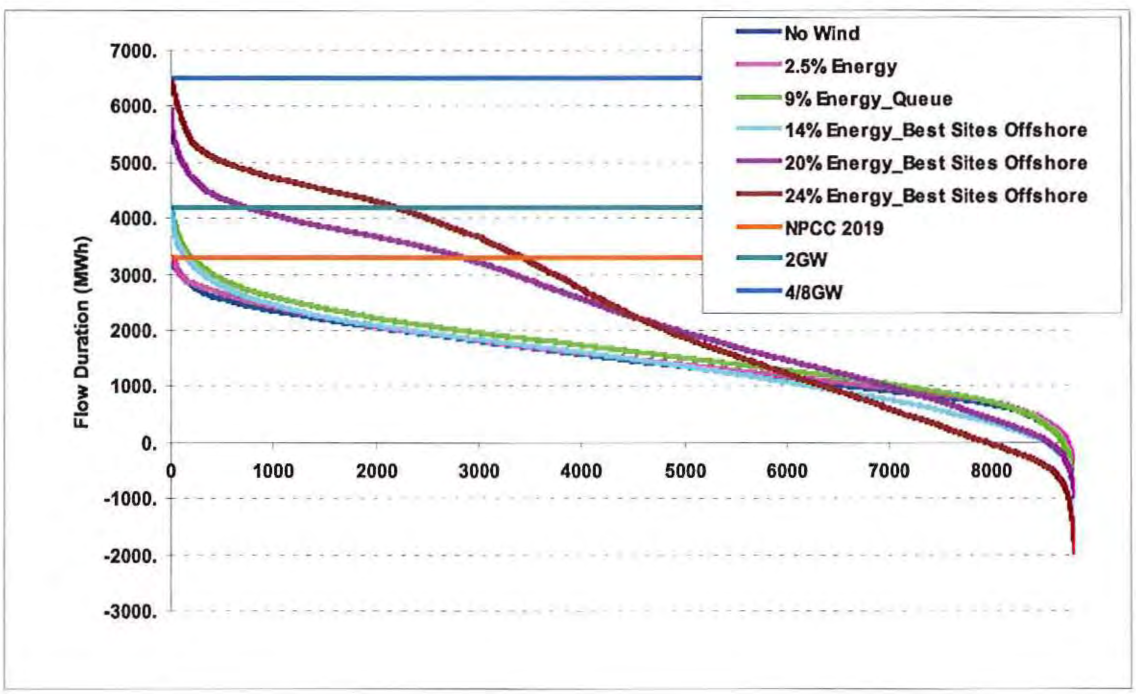


Figure B–49 SEMA/RI Export interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

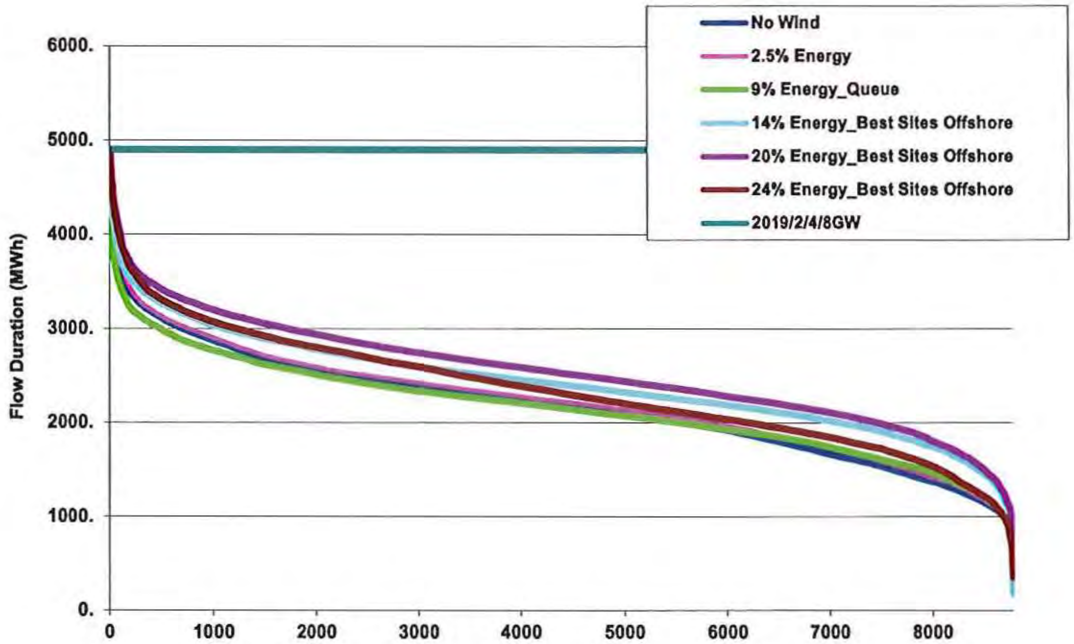


Figure B–50 Boston Import, S-o-A forecast interface flow, Best Sites Offshore, S-o-A Forecast

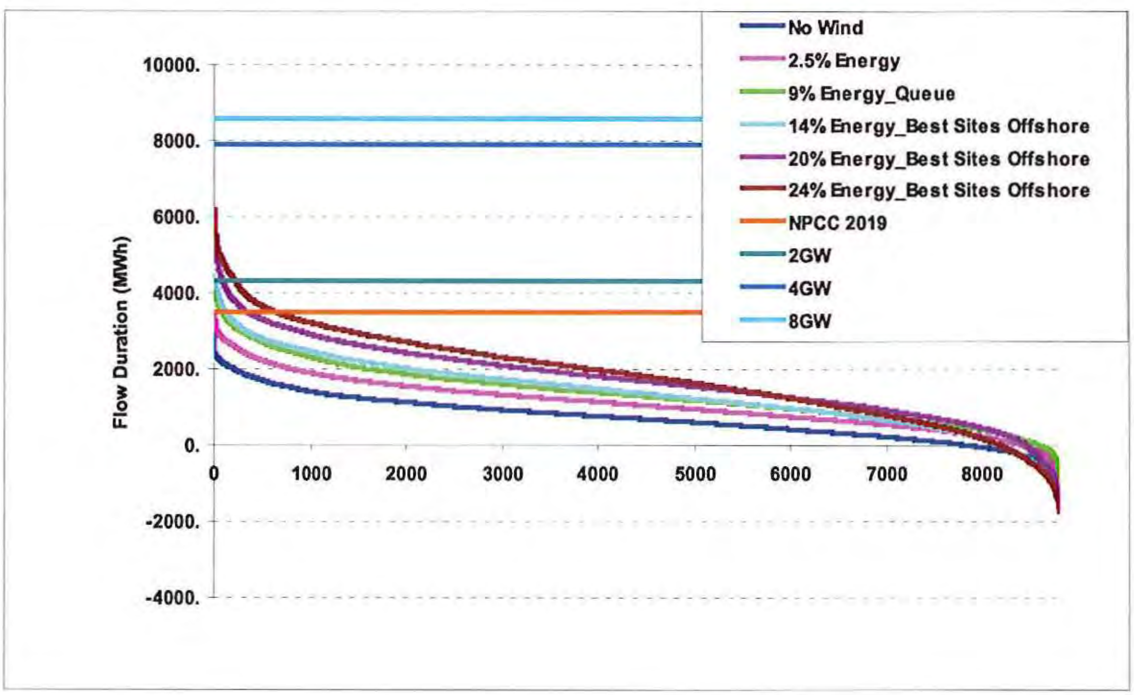


Figure B–51 East-West interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

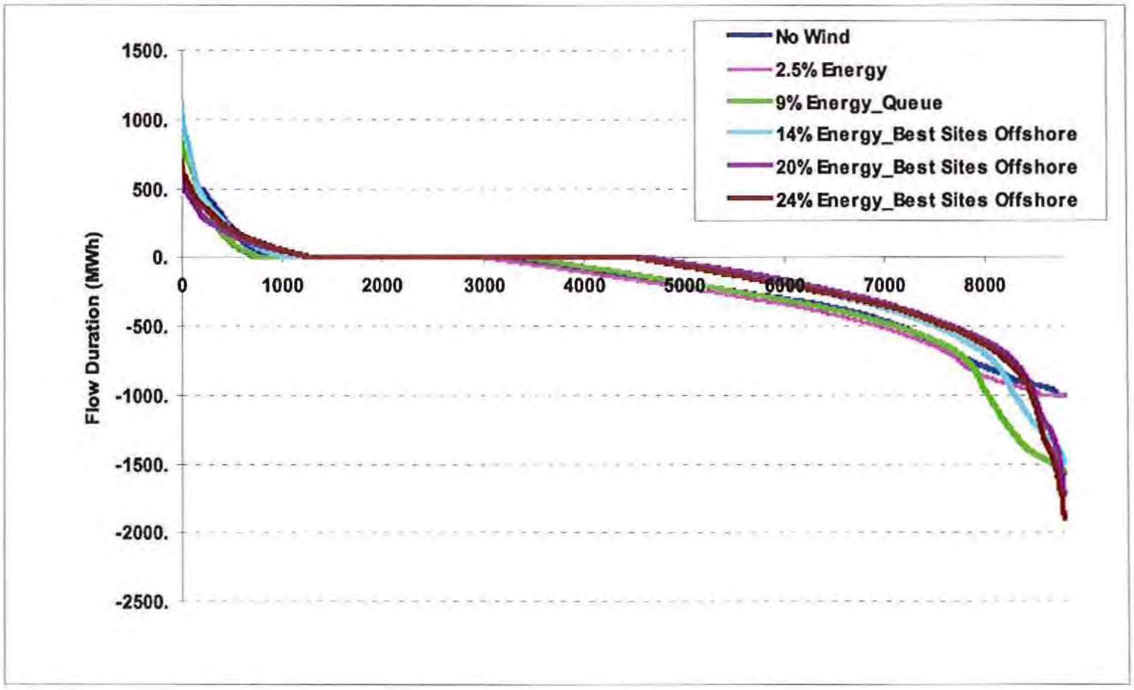


Figure B–52 ISO-NE to NB interface flow, S-o-A forecast, Best Sites Offshore, S-o-A Forecast

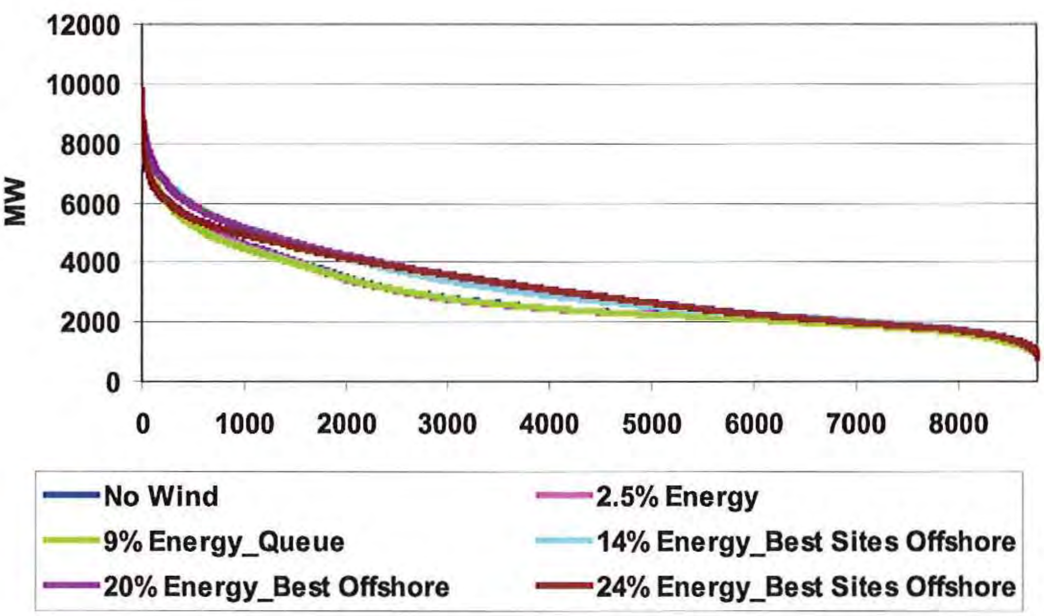


Figure B–53 Hourly Range Up Capability, Best Sites Offshore, S-o-A Forecast

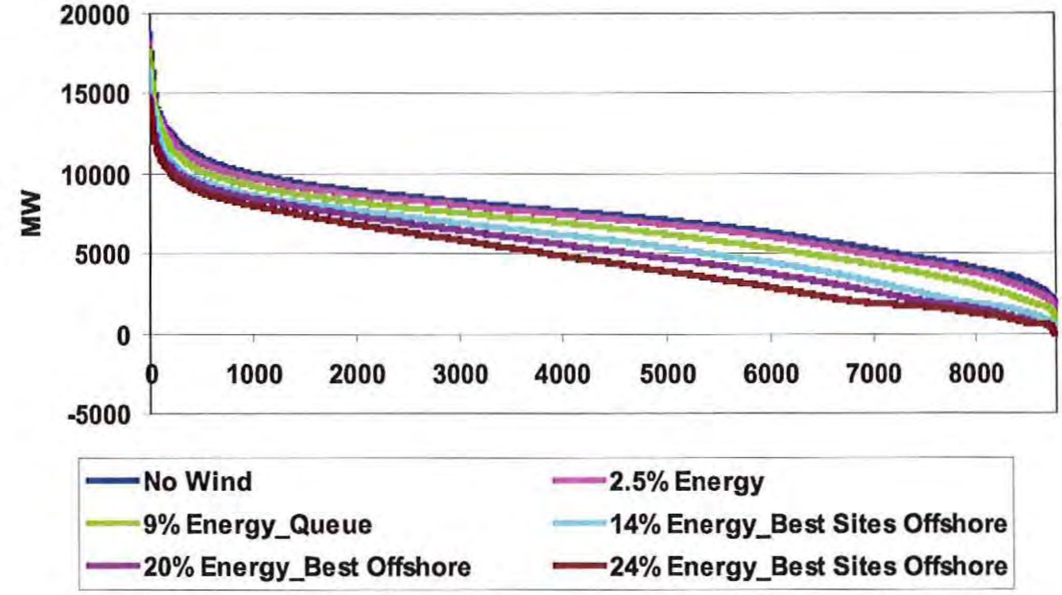


Figure B–54 Hourly Range Down Capability, Best Sites Offshore, S-o-A Forecast

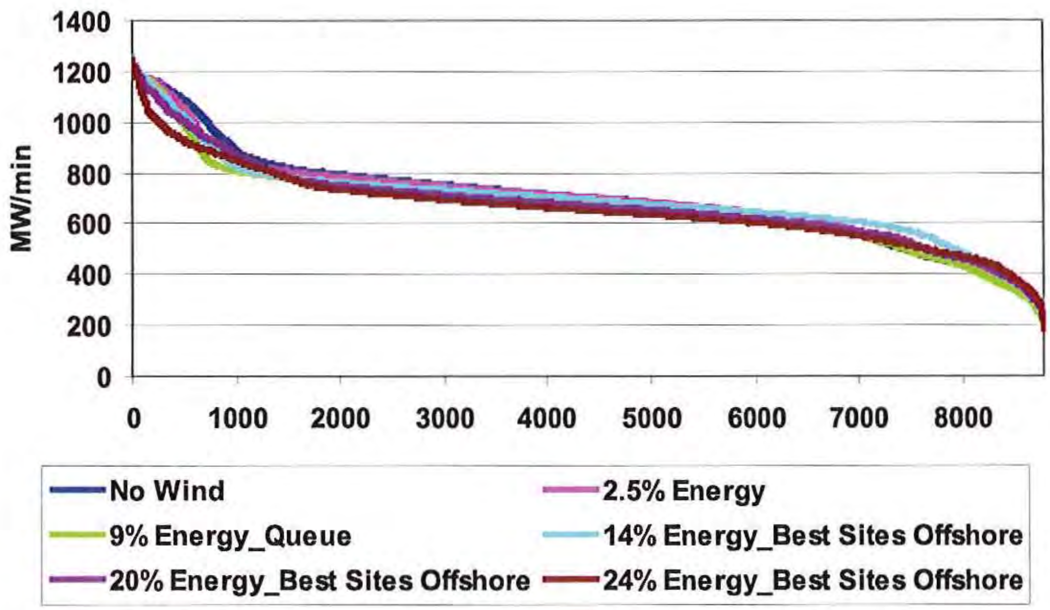


Figure B–55 Hourly Ramp Up Capability, Best Sites Offshore, S-o-A Forecast, S-o-A Forecast

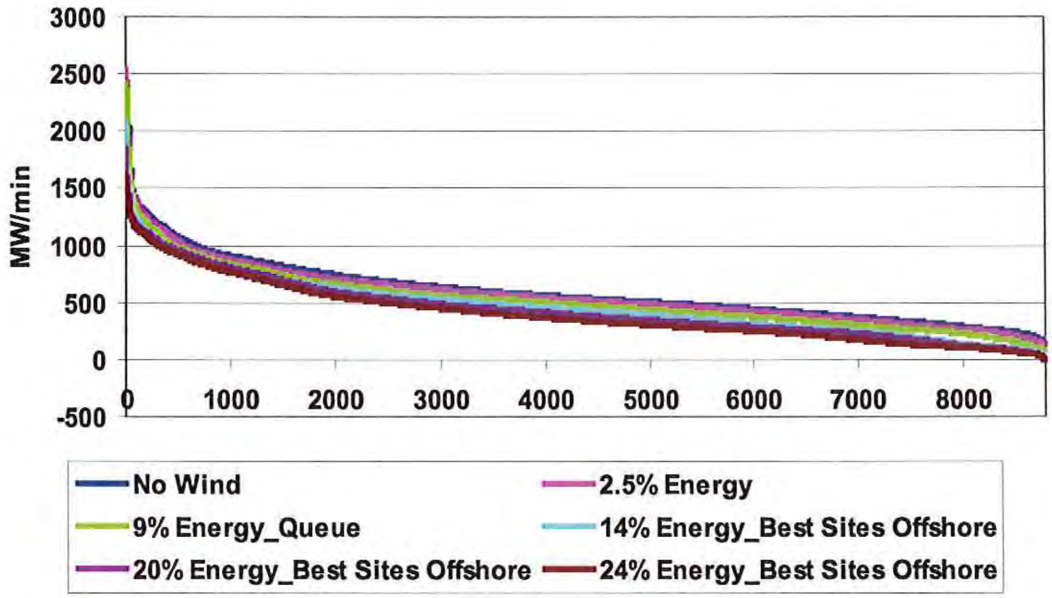
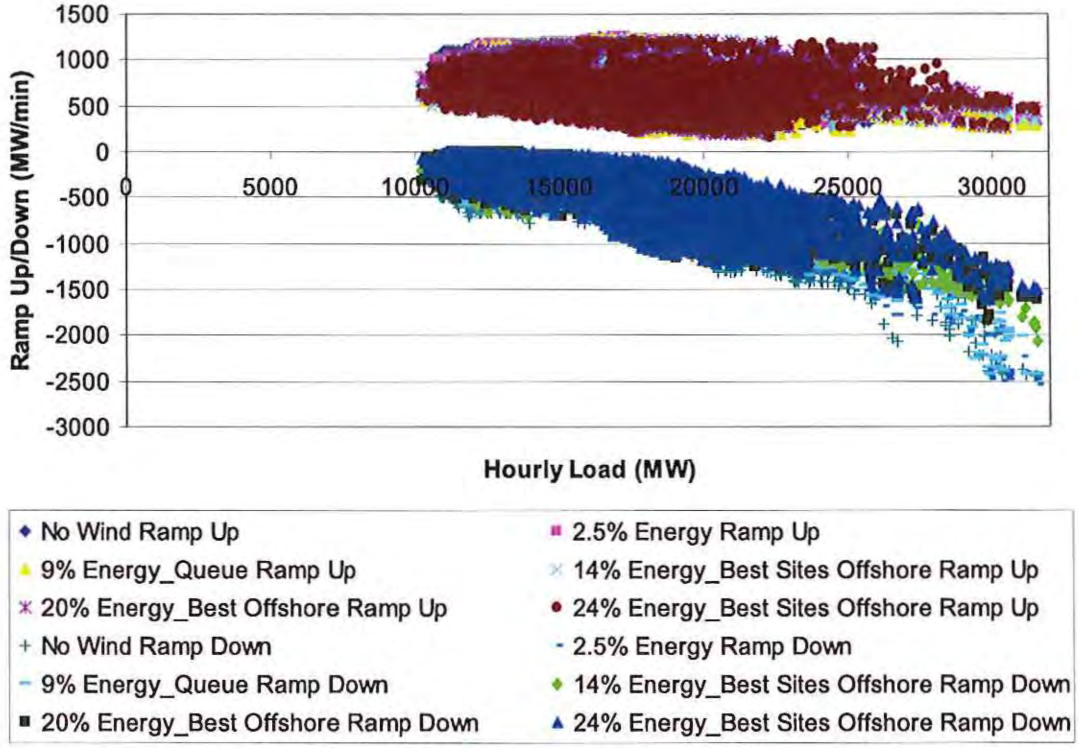


Figure B–56 Hourly Ramp Down Capability, Best Sites Offshore, S-o-A Forecast



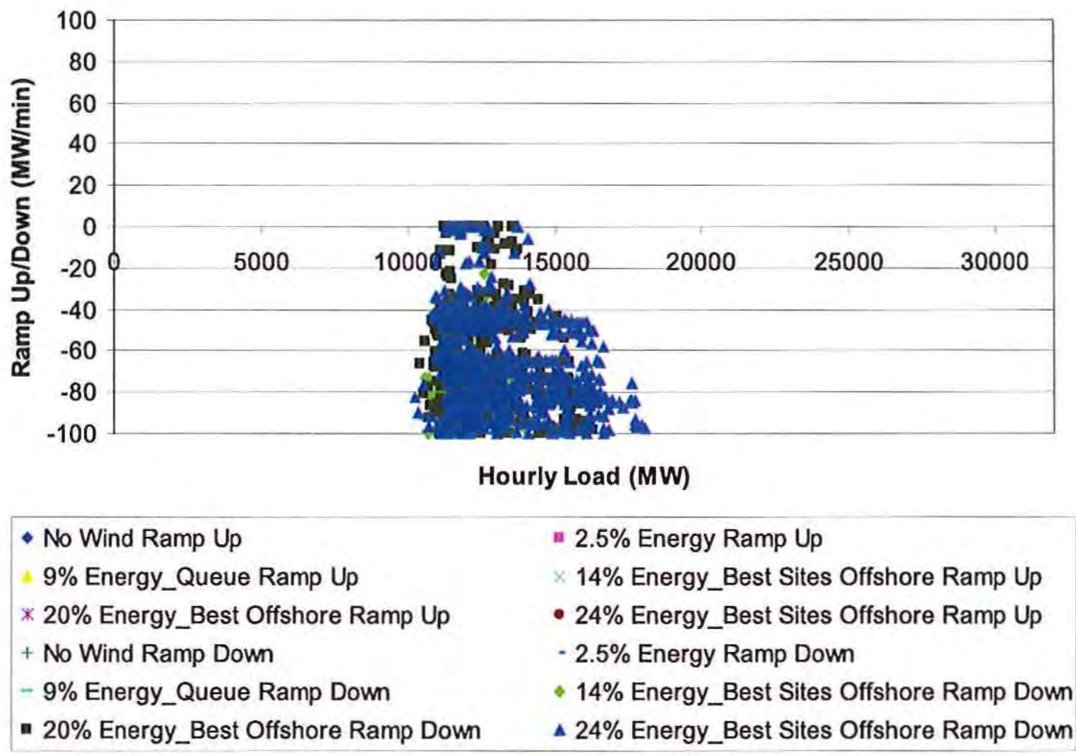


Figure B–57 Hourly Ramp Up/Down CapabilityMW/min vs. Load, S-o-A forecast, Best Sites Offshore

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

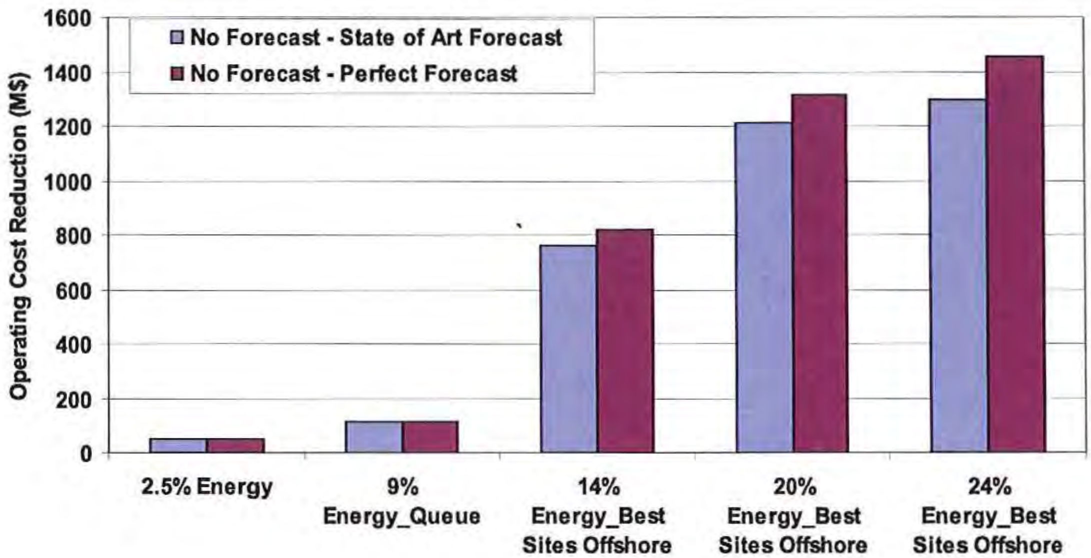


Figure B-58 System operating cost impacts of forecast (M$), Best Sites Offshore

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.

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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.

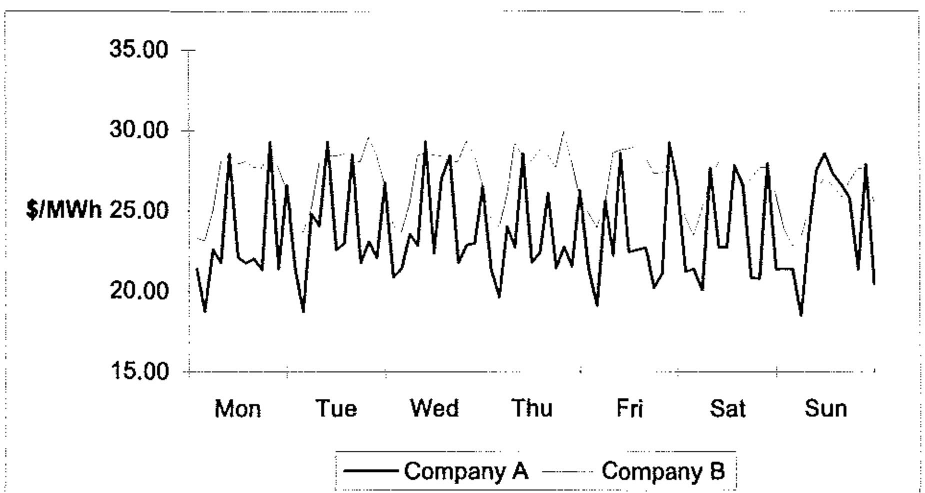


Figure 1. Market clearing prices vary with time and location.

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.

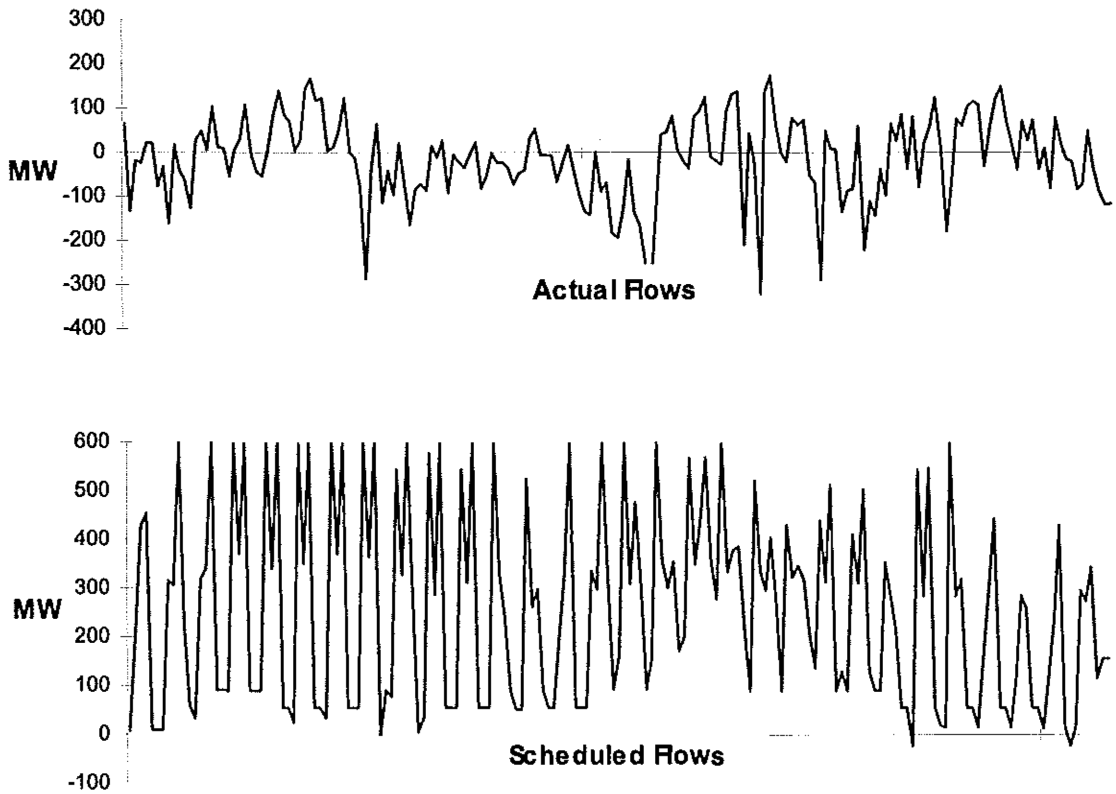


Figure 1. Example of hourly actual and scheduled flows.

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

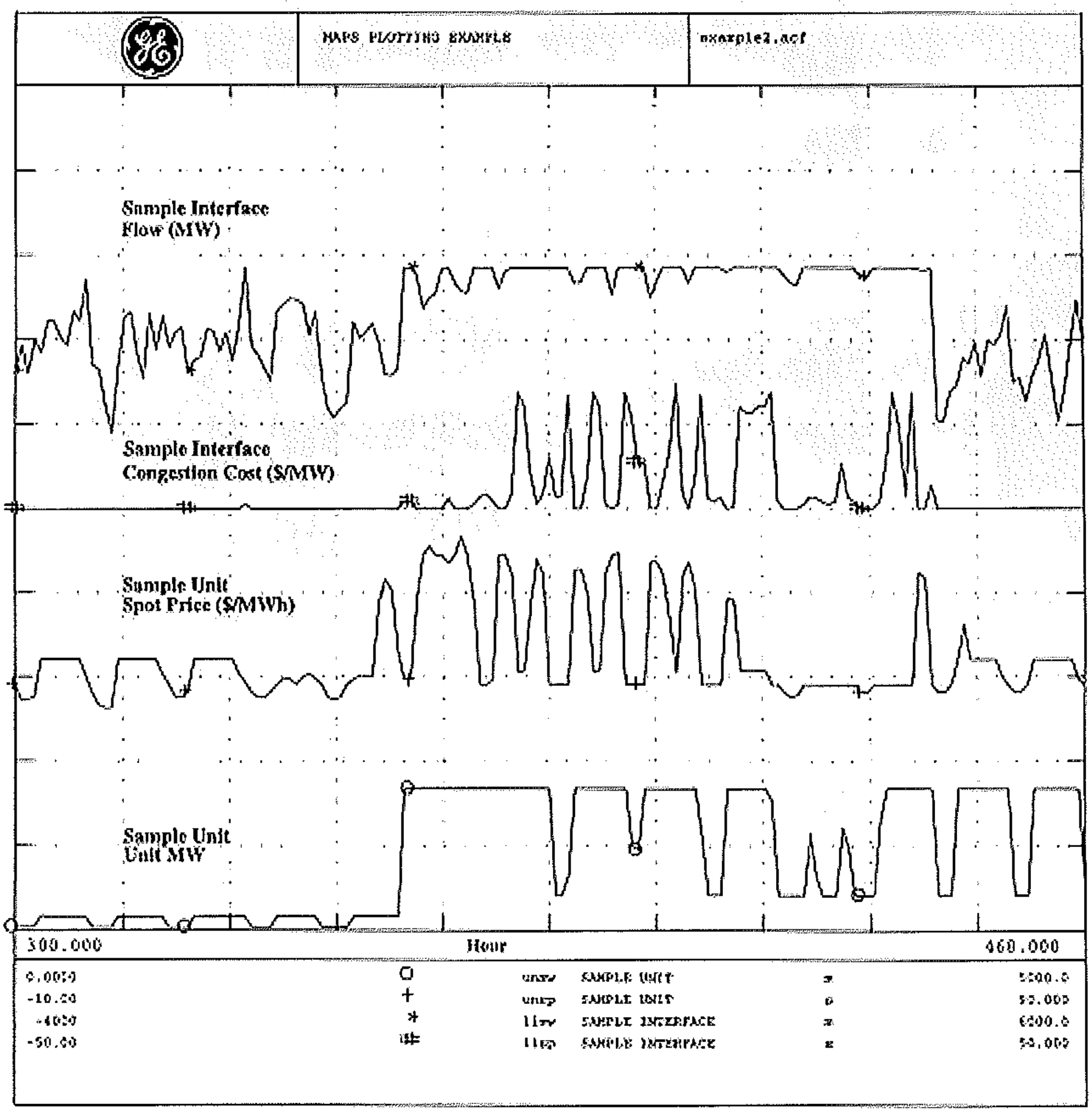
NO	--NAME--	G	H	TYPE	COMPANY	--AREA--	MAX-RTG	CON-RTG	F-O-R	MN-DT	P	TOTAL-GWH	CF	P	FC(k$)	P	OMT(k$)	P	SPMIN	SPMAX
1	Unit-01	0	0	THE	Company A	ATCE_AR	36.00	36.00	0.1040	4	0	0.774	0.0024	0	103	0	1.28	0	11.04	39.81
2	Unit-02	0	0	THE	Company A	ATCE_AR	37.00	37.00	0.1040	4	0	0.777	0.0024	0	102	0	1.29	0	11.04	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
TYPE	Unit type
COMPANY	Unit company
AREA	Unit area
MAX-RTG	Maximum rating in MW
CON-RTG	Continuous rating in MW
F-O-R	Forced outage rate
MN-DT	Minimum downtime (hours)
TOTAL-GWH	Annual GWH operation
CF	Capacity Factor
FC (k$)	Fuel Cost
OMT (k$)	Total O&M Cost
SPMIN	Spot price minimum
SPMAX	Spot price maximum
SPAVG	Spot price average

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



MULTI AREA PRODUCTION SIMULATION PROGRAM
SAMPLE DATA BASE
BASE CASE FROM PUBLIC DATA
Data for the period 1/2000 through 12/2000

Figure 2. Typical Plots Available from MRA

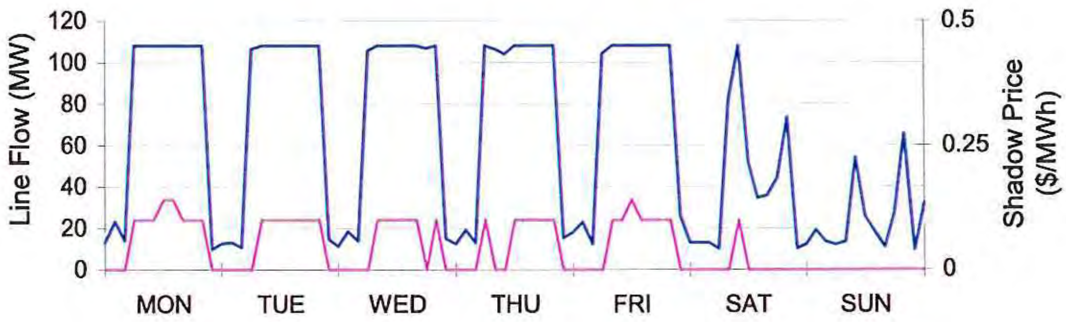


Figure 3. Line Flows and Line Shadow Prices

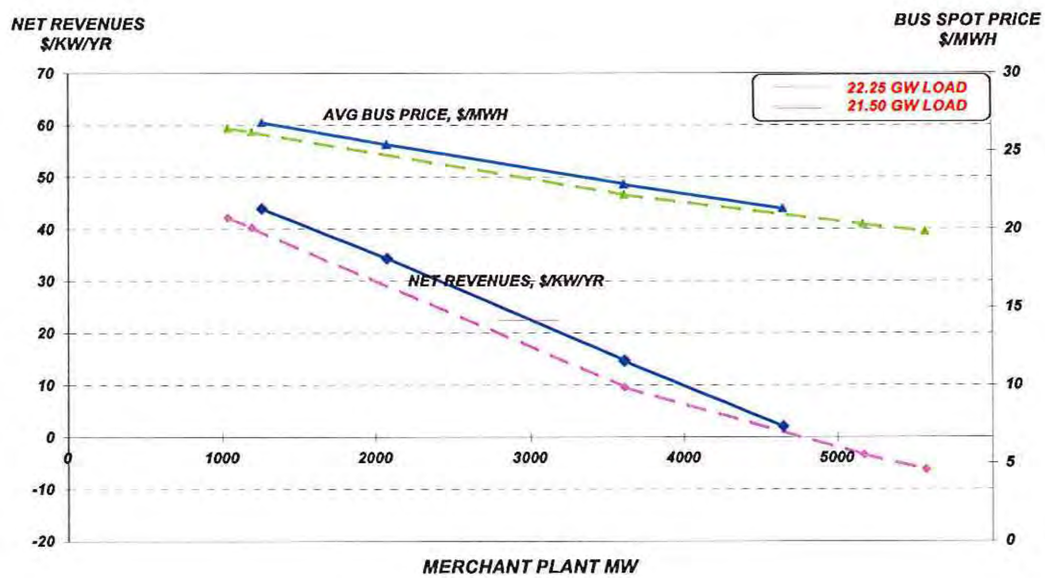


Figure 4. Merchant Plant Net Revenues

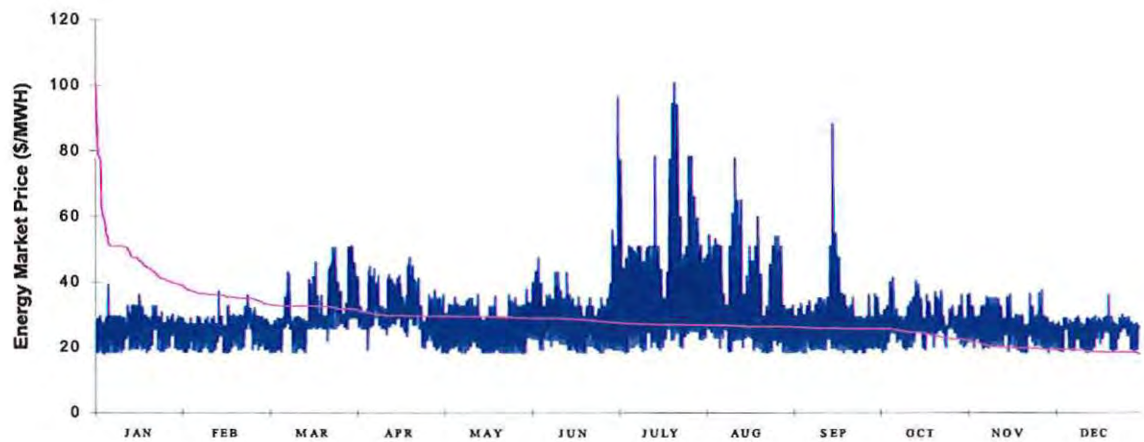


Figure 5. Hourly Market Energy Prices

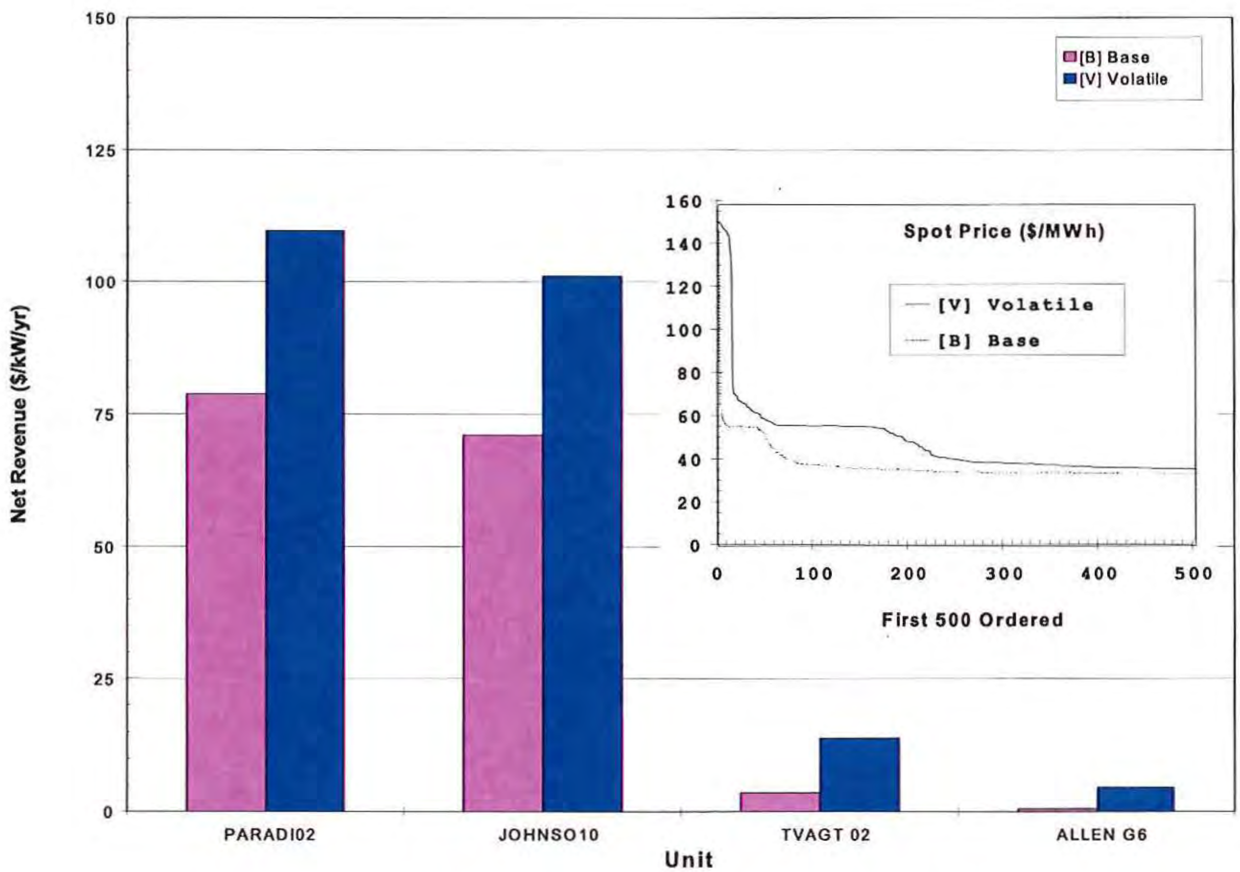


Figure 6. Effect of Market Volatility on Spot Price and Net Revenue

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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[3] R. Mukerji, J. Hajagos, C. Dahl, K.D. Rogers, M. Gopinathan, D. Eyre, "Transmission Constrained Production Simulation - A Key Tool in the De-Regulated Utility Environment," CIGRE 1996 Session, Paris, France, 1996.

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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
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GE Energy
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Schenectady, NY 12345
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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.

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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.