Growing Wind

Final Report of the NYISO 2010 Wind Generation Study



September 2010

Caution and Disclaimer

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Executive Summary

1. Introduction

In 2004, the New York State Public Service Commission (PSC) adopted a Renewable Portfolio Standard (RPS) that requires 25% of New York States' electricity needs to be supplied by renewable resources by 2013. The development of the RPS prompted the New York Independent System Operator (NYISO) and the New York State Energy Research and Development Authority (NYSERDA) to co-fund a study which was designed to conduct a comprehensive assessment of wind technology, and to perform a detailed technical study to evaluate the impact of large-scale integration of wind generation on the New York Power System (NYPS). The study was conducted by GE Power System Energy Consulting in fall of 2003 and completed by the end of 2004 (i.e., "the 2004 Study").

The overall conclusion of the 2004 Study was the expectation that the NYPS can reliably accommodate up to a 10% penetration of wind generation or 3,300 megawatts (MW) with only minor adjustments to and extensions of its existing planning, operation, and reliability practices. Since the completion of the 2004 Study, a number of the recommendations contained in the report have been adopted. They include the adoption of a low voltage ride through standard, a voltage performance standard and the implementation of a centralized forecasting service for wind plants.

The nameplate capacity of installed wind generation has now increased to 1,275 MW and the NYISO interconnection queue significantly exceeds the 3,300 MW that was originally studied. In addition, the PSC has increased New York State's RPS standard to 30% by 2015. As a result, the NYISO has been studying the integration of installed wind plants with nameplate ratings that total from 3,500 MW to 8,000 MW.

From an operational perspective, power systems are dynamic, and are affected by factors that change each second, minute, hour, day, season, and year. In each and every time frame of operation, it is essential that balance be maintained between the load on the system and the available supply of generation. In the very short time frames (seconds-to-minutes), bulk power system reliability is almost entirely maintained by automatic equipment and control systems, such as automatic generation control (AGC). In the intermediate to longer time frames, system operators and operational planners are the primary keys to maintaining system reliability. The key metric driving operational decisions in all time frames are the amount of expected load and its variability. The magnitude of these challenges increases with the significant addition of wind-generating resources.

Variable generation, such as wind and solar, have high fixed costs and very low marginal operating costs which tend to reduce overall production costs and marginal energy prices. However, as will be shown in this study, variable resources require additional resources to be available to respond to the increased system variability, which offsets some of the production cost savings. The primary focus of this report is on the technical impacts of increasing the penetration of wind resources. The impact on production costs, locational-based marginal prices, congestion costs and uplift are presented based on the production costs simulations that were conducted. The study did not conduct, nor did the study scope contemplate, a full economic evaluation of the costs and benefits of wind generation.

2. Technical Approach

Due to its variable nature and the uncertainty of its output, the pattern of wind generation has more in common with load than it does with conventional generation. Therefore, the primary metric of interest in assessing the impact of wind on system operations is “net load,” which is defined as the load minus wind. It is net load to which dispatchable resources consisting of primarily fossil fired generation must be able to respond. The study evaluated the impact of up to 8,000 MW of wind-generation resources on system variability. The study process consisted of the following tasks:

Task 1: Develop wind generator penetration scenarios for selected study years including MW output profile and MW load profile.

Task 2: Develop and implement performance-monitoring processes for operating wind generators.

Task 3: Update the review of the European experience conducted for the 2004 study with currently existing wind plants, and review the experiences and studies for wind plants in other regions of the US and Canada.

Task 4: Study the potential impact on system operations of wind generators at various future levels of installed MW for the selected study years as it relates to regulation requirements and the overall impact on ramping.

Task 5: Evaluate the impact of the higher penetration of wind generation from a system planning perspective – including the evaluation of transmission limitations – by identifying specific transmission constraints (limiting element/contingency) for each wind project (or group of projects)

Task 6: Evaluate the impact of the higher penetration of wind generation on the overall system energy production by fuel types, locational-based marginal prices (LBMP), congestion cost, operating reserves, regulation requirements, and load following requirements.

Task 7: Identify the impact of transmission constraints on wind energy that is not deliverable (i.e., “bottled”) and identify possible upgrades for the limiting elements/transmission facilities.

The technical analysis required by the study task includes a set of sequential steps that are needed to successfully conduct a comprehensive analysis of integrating wind into the grid as a function of penetration level. In addition to the traditional planning analysis and economic assessments, the integration of a variable generation resources requires the assessment of operational issues as well. Operational analyses in conjunction with traditional planning assessments are necessary to fully understand the overall technical implication and potential cost associated with integrating variable generation resources. This process includes the following steps:

Step 1: A determination of the interconnection point of the resources and potential output

Step 2: A thorough assessment of the transmission system to determine the contingencies and constraints that could adversely impact wind

Step 3: A statistical analysis of the interaction of load and wind as measured by the net load to determine the impact of variable wind resources on overall system variability and operational requirements

Step 4: Dispatch simulation with a production cost tool to determine the amount of wind that will be constrained and the impact of wind on the overall dispatchablility such as plant commitment and economics of the system

Step 5: An identification and rank ordering of the transmission constraints that impact the dispatchablility of wind

Step 6: Development of transmission upgrades to relieve wind constraints for the various penetration levels of wind

Step 7: Redo Step 4 with upgrades and needed operational adjustments determined in Step 3 to determine the full impact

Step 8: Conduct a dynamic assessment to determine if the planned system with the higher levels of wind will satisfy stability criteria

Step 9: Conduct loss-of-load-expectation (LOLE) analysis to determine the impact of installed wind on system load carrying capability or reserve margin requirements.

The study spanned a period of time from the spring of 2008 to the spring of 2010 and involved an extensive review of not only the New York Control Area (NYCA) bulk power system, but the underlying 115 kV transmission system as well. It also involved significant feed-forward and feedback between the power flow analysis and the simulation of NYISO security constrained economic dispatch. This process was used to determine the impact of transmission constraints on the energy deliverability of the wind plants as well as how relieving the transmission constraints affected the energy deliverability of the wind plants. Given the study scope and the plant-by-plant analysis, this study is one of the most comprehensive assessments undertaken for evaluating wind integration for a large balancing area.

3. Study Findings

The study has determined that as the level of installed wind plant generation increases, system variability, as measured by the net-load, increases for the system as whole. The increase exceeds 20% on an average annual basis for the 8 GW wind scenario and the 2018 loads. The level of increase varies by season, month, and time-of-day. This will result in higher magnitude ramping events in all timeframes. Ramp is the measure of the change in net load over time to which the dispatchable resources need to respond. Study results are reported for the New York system as a whole and for three superzones (Western load zones A-E, Hudson Valley load zones F-I, and the New York City and Long island load zones J-K). The study resulted in the following findings with respect to system reliability, system operations and dispatch, and transmission planning.

3.1 Reliability Finding:

This study has determined that that the addition of up to 8 GW of wind generation to the New York power system will have no adverse reliability impact. The 8 GW of wind would supply in excess of 10% of the system's energy requirement. On a nameplate basis, 8 GW of wind exceeds 20% of the expected 2018 peak load. This finding is predicated on the analysis presented in this report and the following NYISO actions and expectations:

The NYISO has established a centralized wind forecasting system for scheduling of wind resources and requires wind plants to provide meteorological data to the NYISO for use in forecasting their output. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2008.*

The NYISO is the first grid operator to fully integrate wind resources with economic dispatch of electricity through implementation of its wind energy management initiative. If needed to maintain system security, the NYISO system operators can dispatch wind plants down to a lower output. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2009.*

The NYISO's wind plant interconnection process requires wind plants: 1) To participate fully in the NYISO's supervisory control and data acquisition processes; 2) To meet a low voltage ride through standard; and 3) conduct voltage testing to evaluate whether the interconnection of wind plants will have an adverse impact on the system voltage profile at the point of interconnection. In addition, the NYISO will continue to integrate best practice requirements into its interconnection processes.

The NYISO's development of new market rules assist in expanding the use of new energy storage systems that complement wind generation. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2009.*

The NYISO's installed resource base will have sufficient resources to support wind plant operations. As described in this report, the overall availability of wind resources is much less than other resources and their variability (changing output as wind speed changes) increases the magnitude of the ramps. For a system that meets its resource adequacy criteria (e.g., the 1 day in ten years), the additions of 1 MW of resources generally means that 1 MW of existing resources could be removed and still meet the resource adequacy criteria. However, the addition of 1 MW of wind would allow approximately 0.2

MW to 0.3 MW of existing resources to be removed in order to still meet the resource adequacy criteria. The balance of the conventional generation must remain in service to be available for those times when the wind plants are unavailable because of wind conditions and to support larger magnitude ramp events.

3.2 Operation and Dispatch Simulation Findings:

Analysis of the wind plant output and dispatch simulations resulted in the following findings for the expected impact of wind plant output on system operations and dispatch:

Finding One - Analysis of five minute load data coupled with a ten minute persistence for forecasting wind plant output (i.e., wind plant output was projected to maintain its current level for the next five minute economic dispatch cycle) concluded that increased system variability will result in a need for increased regulation resources. The need for regulation resources varies by time of day, day of the week and seasons of the year. The analysis determined that the average regulation requirement increases approximately 9% for every 1,000 MW increase between the 4,250 MW and 8,000 MW wind penetration level. The analysis for 8 GW of wind and 2018 loads (37,130 MW peak) resulted in the overall weighted average regulation requirement increasing by 116 MW. The maximum increase is 225 MW (a change from a 175 MW requirement up to 400 MW) for the June-August season hour beginning (HB) 1400. The highest requirement is 425 MW in the June-August season HB2000/HB2100.

Finding Two - The amount of dispatchable fossil generation committed to meet load decreases as the level of installed nameplate wind increases. However, a greater percentage of the dispatchable generation is committed to respond to changes in the net-load (load minus wind) than committed to meet the overall energy needs of the system. The magnitudes of ramp or load following events are reduced when wind is in phase with the load (i.e., moving in the same direction). However, for many hours such as the morning ramp or the evening load drop, wind is out of phase with the load (i.e., moving in the opposite direction). These results in ramp or net-load following events that are of higher magnitude than those that would result from changes in load alone. It is these ramp or load following events to which the dispatchable resources must respond.

Finding Three - Simulations with 8 GW of installed wind resulted in hourly net-load up and down ramps that exceeded by approximately 20% the ramps that resulted from load alone. It was also determined from the simulations the NYISO security constrained economic dispatch processes are sufficient to reliably respond to the increase in the magnitude of the net-load ramps. This finding is based on the expectation that sufficient resources will be available to support the variability of the wind generation. For example, the data base used for these simulations had installed reserve margins which exceeded 30%.

Finding Four - Simulations for 8 GW of wind generation concluded that no change in the amount of operating reserves[1] was needed to cover the largest instantaneous loss of source or contingency event. The system is designed to sustain the loss of 1,200 MW instantaneously with replacement within ten minutes where as a large loss of wind generation occurs over several minutes to hours. The

[1] Operating reserves is the amount of resources that are needed to be available for real-time operations to cover the instantaneous and unexpected loss of resources. The New York power system is operated to protect the system against the sudden loss of 1,200 MW of resources. Operating reserve as stated is an operational concept while the reserve margin discussed in section 3.3 is a planning concept. The required reserve margin is designed to maintain, at an acceptable level, the risk of not having sufficient resources to avoid an involuntary loss-of-load event.

analysis of the simulated data found for 8 GW of installed wind a maximum drop in wind output of 629 MW occurred in ten minutes, 962 MW in thirty minutes and 1,395 MW in an hour, respectively.

3.3 Resource Adequacy Findings:

To evaluate the impact of wind resources on NYISO installed reserve requirements, the study started with the New York State Reliability Council (NYSRC) Installed Reserve Margin[2] Study for the 2010-2011 Capability Year.[3] The NYSRC base case had an installed reserve margin of 17.9% to meet loss-of-load-expectation (LOLE) criteria of 0.1 days per year. That base case was updated to bring the installed wind resources to the full 8 GW of wind studied. The analysis of a system with this level of installed wind resulted in the following findings.

Finding One – All other things being equal, the addition of 8 GW of wind resources to the NYSRC base case reduced the LOLE from the 0.1 days per year to approximately 0.02 days per year.

Finding Two – To meet the required reliability criteria, the NYISO reserve margin would have to increase from its current level of 18% to almost 30% with 8 GW of nameplate wind as part of the resource mix. This was determined by using the methodology of removing capacity to bring the system to criteria and adding transfer capability in order for the wind plants to qualify for Capacity Rights Interconnection Service (CRIS). However, it should be noted that the NYISO's capacity market requires load serving entities to procure unforced capacity (UCAP) and capacity is derated to its UCAP value for purchase. As a result the total amount UCAP that needs to be purchased to meet reliability criteria remains essentially unchanged. The increase in reserve margin is because on capacity basis 1 MW of wind is equivalent to approximately 0.2 MW to 0.3 MW of conventional generation. Therefore, it requires a lot more installed wind to provide the same level of UCAP as a conventional generator. This results in an increase in the installed reserve margin which is computed on an installed nameplate basis.

Finding Three – The LOLE analysis resulted in an effective load carrying capability (ELCC) for the wind plants studied that exceeded 20%. The ELCC for this study exceeded the ELCC finding in the 2004 study by a factor of 2. Off-shore wind exhibits ELCC that is higher than on-shore wind because a greater percentage of the off-shore wind plants energy production occurs during peak hours. As an example, the GridView wind plant simulations based on 2006 wind data resulted in a 37.4% overall annual capacity factor (CF) for off-shore wind VS 34.3% for on-shore wind. However, the CF for off-shore wind plants during peak hours (the hours between 7am and 11 pm weekdays) was 39.7% for off-shore wind VS 32.5% for on-shore wind.

3.4 Production Cost Simulation Findings:

The production cost simulations conducted with ABB's GridView economic dispatch simulation model and the base case transmission system resulted in the following findings:

[2] Reserve margin is the amount of additional capacity above the peak load that is needed so that the risk of not having sufficient capacity available to meet the load meets the minimum reliability criteria. It is expressed as a percentage and is calculated by dividing the required level of resources by the expected peak load. Resources can be unavailable because of equipment failure, maintenance outage, lack of fuel, etc. The higher the unavailability of the overall resource mix, the higher the installed reserve margin will be.

[3] http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

Finding One - As the amount of wind generation increases, the overall system production costs decrease. For the 2013 study year, the production costs drop from the base case total of almost $6 billion to a level of approximately $5.3 billion for the 6,000 MW wind scenario. This represents a drop of 11.1% in production costs. For the 2018 study year, the production costs drop from the base case total of almost $7.8 billion to a level of approximately $6.5 billion for the 8,000 MW wind scenario. This represents a drop of 16.6% in production costs. The change in production costs reflect the commitment of resources that are needed to support the higher magnitude ramping events but do not reflect the costs of the additional regulating resources.

Finding Two - Based on the economic assumptions used in the CARIS study, locational-based marginal prices (LBMP) or spot prices decline as significant amounts of essentially zero production cost generation that participates as price taker is added to the resource mix. For the 2018 simulations, the NYISO system average LBMP prices are 9.1% lower for the 8 GW wind scenario when compared to the base case or 1,275 MW of installed wind.

Finding Three - The LBMP price impacts are greatest in the superzones where the wind generation is located and tends to increase the price spread between upstate where wind is primarily located in the study and downstate, which implies an increase in transmission congestion.

Finding Four - The primary fuel displaced by increasing penetration of wind generation is natural gas. For the simulations with 8 GW of wind with 2018 loads, the total amount of fossil-fired generation displaced was approximately 15,500 GWh. Gas-fired generation accounted for approximately 13,000 GWh or approximately 84% of the total. Oil and coal accounted for approximately 2,050 GWh and 465.1 GWh respectively, or approximately 13% and 3% of the total fossil generation displaced.

Finding Five - As suggested by the LBMP trends, the congestion payments in superzones F-I and J-K increase as the level of installed wind generation is increased. The overall increase in congestion payments on a percentage basis as measured against the base case compared to 6,000 MW of wind in 2013 and 8,000 MW in 2018 ranges from a high of 85% for superzone F-I in 2013 to a low of 64% for superzone J-K in 2018.

Finding Six - The addition of wind resources to superzone J-K in the 2018 case puts downward pressure on LBMPs in those zones, and therefore lowers congestion payments.

Finding Seven - Uplift costs tend to increase in superzones A-E and F-I as the level of installed wind generation increases. Superzone J-K uplift cost are for the most part flat as the level of installed wind increases for 2013 but actually decreases for 2018. This is the result of the offshore wind which has a capacity factor of almost 39% and tends to be more coincident with the daily load cycle and displaces high cost on peak generation in the superzone while requiring less capacity for higher magnitude ramping events. Off shore wind also provides greater capacity benefits.

Finding Eight - The capacity factors for the thermal plants are, as expected, decreased by the addition of wind plants, but this is partially offset by increasing load. The biggest reduction in annual capacity factors from the 2013 base case level of 1,275 MW of wind when compared to the 8 GW scenarios occurs for the combined cycle plants in all superzones with a 30% decline in superzone A-E, 11% decline in superzone F-I and 6% decline superzone J-K. As would be expected the biggest impact is in the superzone with the highest level of installed wind with transmission capacity limitations between the superzones contributing to the reduction.

3.5 Environmental Findings:

For the 2018 load levels, the dispatch simulations with 8 GW of wind resources resulted in the following emissions reductions in comparison to the base case with 1,275 MW of installed wind:

Finding One – A CO_2 emission reduction of approximately 4.9 million short tons or a reduction of 8.5%.

Finding Two - Each GWh of displaced fossil-fired generation which primarily consisted of natural gas resulted in an average reduction in CO_2 of approximately 315 tons.

Finding Three - A NOx emission reduction of approximately 2,730 short tons or a reduction of 7%.

Finding Four – A SO_2 emissions reduction of 6,475 short tons or a reduction of 9.7%.

3.6 Transmission Planning Findings:

Extensive power flow analysis in conjunction with dispatch simulations was conducted to determine the impact of transmission system limitations on the energy deliverability of the wind plant output. The analysis resulted in the following findings:

Finding One - Given the existing transmission system capability, the 6 GW scenario determined that 8.8% of the energy production of the wind plants in three areas in upstate New York would be “bottled” or not deliverable.

Finding Two – The primary location of the transmission constraints was in the local transmission facilities or 115 kV voltage level.

Finding Three - The off-shore wind energy as modeled was fully deliverable and feeds directly into the superzone J-K load pockets.

Finding Four - The study evaluated 500 miles of transmission lines and 40 substations to determine potential upgrades that would result in the “unbottling” of the wind energy.

Finding Five - If all the upgrades studied were implemented, the amount of wind energy not deliverable would be reduced to less than 2% of the upstate wind.

Finding Six - Depending on the scope of upgrades required, such as reconductoring of transmission lines compared to rebuilding or upgrading terminal equipment, the cost of the upgrades could range from $75 million to $325 million. However, it should be noted that many of the transmission facilities studied are approaching the end of their expected useful lives.

Finding Seven - Transient Stability Analysis was conducted to evaluate the impact of high wind penetration on NYCA system stability performance. The primary interface tested was the Central East. The Central East stability performance has been shown historically to be key factor in the dynamic performance of the NYISO power grid. The NYISO power grid (and the Interconnection) system demonstrated a stable and well damped response (angles and voltages) for all the contingencies tested on high wind generation on-peak and off-peak cases. There is no indication of units tripping due to over/under voltage or over/under frequency.

Finding Eight - Wind plants that are in the NYISO interconnection 2008 class year study and beyond may require system deliverability upgrades to qualify for Capacity Resource Integration Service (CRIS). This totals approximately 4,600 MW of new nameplate wind plants that were included in the study. In order to qualify for capacity payments, the wind plants in class year 2009/2010 and beyond in upstate New York would need to increase transmission transfer capability between upstate New York and southeast New York (a.k.a., the UPNY-SENY interface). This transmission interface primarily consists of 345 kV transmission lines in the Mid-Hudson valley region running through Greene County, New York south of Albany to Dutchess County, New York or between Zones E and F and Zone G. The study determined that approximately 460 MW of interface transfer capability needs to be added to this interface for the wind plants that did not qualify for capacity payments to be eligible for them. This does not impact the deliverability of the wind plants' energy but only their ability to qualify for capacity payments or CRIS.

4. Conclusions:

The primary finding of the study is that wind generation can supply reliable clean energy at a very low cost of production to the New York power grid. This energy results in significant savings in overall system production costs, reductions in “greenhouse” gases such as CO_2 and other emissions such as NOx and SO_2 as well an overall reduction in wholesale electricity prices. However, wind plants require a significant upfront capital investment. In addition, wind plants, because of their variable nature and the uncertainty of their output, provide a greater challenge to power system operation than conventional power plants. This study determined that the NYISO’s systems and procedures (which include the security constrained economic dispatch and the practices that have been adopted to accommodate wind resources) will allow for the integration of up to 8 GW of installed wind plants without any adverse reliability impacts.

This conclusion is predicated on the assumption that a sufficient resource base is maintained to support the wind. The study determined that 8 GW of wind would reduce the need for conventional or dispatchable fossil fired generation on the order of 1.6 to 2 GW or an amount equivalent to 20-25% of the installed nameplate wind. This is the result of the much lower overall availability of wind-produced Energy, when compared to conventional generation. This means an amount of fossil generation equivalent to 75-80% of the nameplate installed wind needs to be available for those times when the wind isn’t blowing or the wind plant output is at very low levels. Non-wind generation is needed to respond to the higher magnitude ramps that will result because of winds variable nature.

As wind resources are added to the resource mix, their lower availability could result in an increase in the installed reserve margin and a decline in spot market prices. The impact of these changing conditions has not been analyzed in this report.

The fluctuating nature and the uncertainty associated with predicting wind plant output levels manifests itself as an increase in overall system variability as measured by the net load (load minus wind). In response to these increased operational challenges the NYISO has implemented changes to its operational practices such as being the first ISO to incorporate variable generation resources into security constrained economic dispatch (SCED) and to implement a centralized forecasting process for wind resources. The study concluded that at higher levels of installed wind generation the system will experience higher magnitude ramping events and will require additional regulation resources to respond to increased variability during the five minute dispatch cycle. The analysis determined that the average regulation requirement will need to increase by approximately 9% for every 1,000 MW increase in wind generation between the 4,250 MW and 8,000 MW.

Although the addition of wind to the resource mix resulted in significant reduction in production costs, the reduction would have been even greater if transmission constraints between upstate and downstate were eliminated. These transmission constraints prevent lower cost generation in upstate New York from displacing higher costs generation in southeast New York. This report did not analyze the potential financial impact of an increase in transfer capability from upstate into southeast New York.

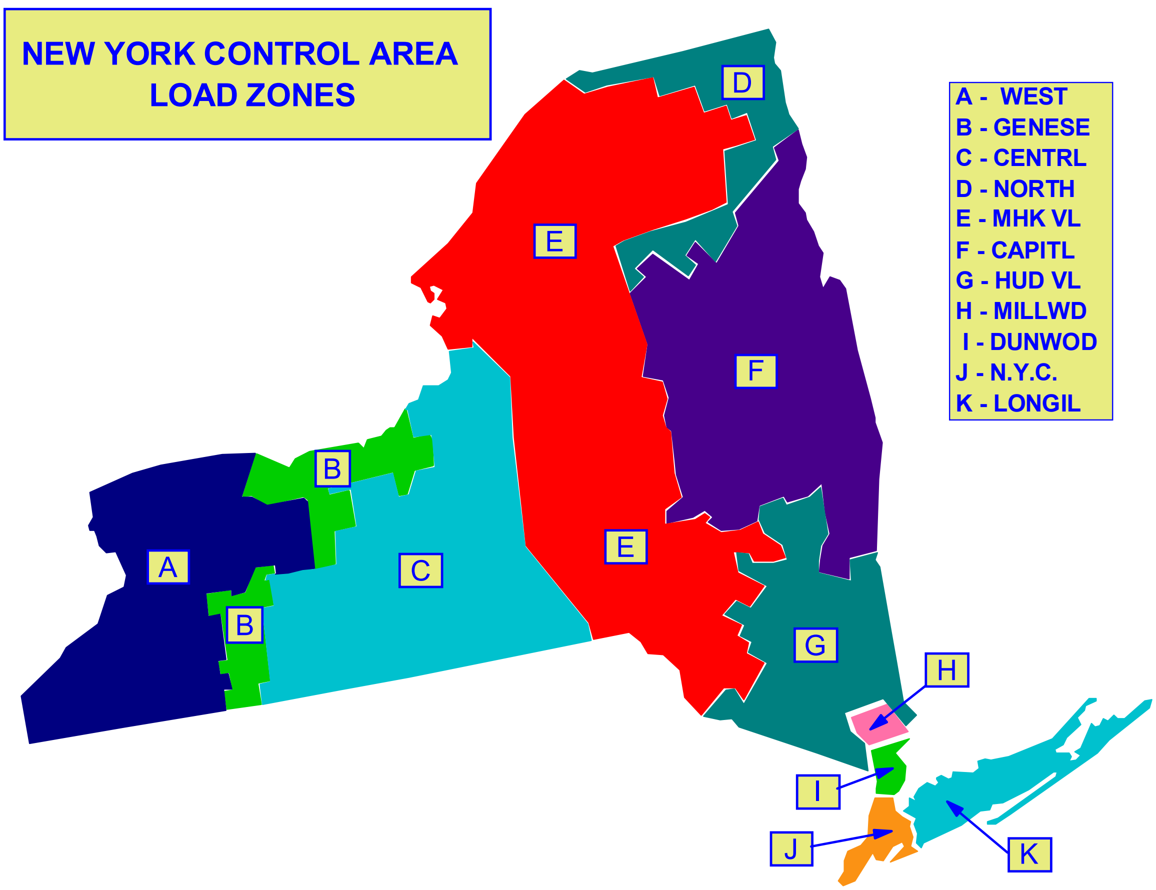
Finally, the study determined that almost 9% of the potential upstate wind energy production will be “bottled” or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades to eliminate the transmission limitations. These upgrades were evaluated to determine how much of the wind energy that was undeliverable would be deliverable if the transmission limitations were removed. Additional alternatives were suggested and evaluated to address the significant levels of resource bottling that occurs in the Watertown vicinity. The suggested transmission upgrades and alternatives require a detailed physical review and economic evaluation before a final set of recommendations can be determined.

In addition to the findings presented in this Executive Summary, the main body of the report offers other findings as well as additional support for the findings presented in the executive summary. The report also contains an update of the review of the European experience with variable generation that was part of the 2004 study and there are summaries of wind integration studies by the California ISO, the Ontario Power Authority in Canada and the Electric Reliability Council of Texas.

NYISO Wind Generation Study

1. Purpose

This document presents the results of a study of 8,000 MW of wind generation on the New York Control Area – see map below. The purpose of the study was two fold: 1) To update the GE study that was conducted in 2004 for wind generation up to 3,300 MW; and 2) To identify issues that will need to be addressed and initiatives that will be need to be undertaken to integrate several thousand MW of wind generation. The primary focus of the report is on the technical impacts of increasing the penetration of wind resources. The impact on production costs, locational marginal prices, congestion costs and uplift are presented based on the production costs simulations that were conducted. The study did not conduct nor did the study scope contemplate a full economic evaluation of the costs and benefits of wind generation.



2. Background

The implementation of policies and the adoption of regulations designed to encourage the development of renewable energy technologies is resulting in the significant growth in the installed base of wind generation in the New York Control Area (NYCA) as well as throughout the North America. Given wind generation's variable and less predictable nature and technology characteristics, industry experience and studies have indicated that large-scale wind generation has a unique set of impacts on power system operation. While these impacts may be relatively small at low penetration levels, as penetration levels increase, physical transmission system reinforcements and special bulk power system planning and operating practices may be required. Therefore, these potential impacts need to be fully understood to guarantee the reliable operation and planning of the New York Power System (NYPS).

In September of 2004, New York State adopted a Renewable Portfolio Standard that requires 25% of New York States' electricity needs be supplied by renewable resources by 2013. This requirement resulted in the New York Independent System Operator and the New York State Energy Research and Development Authority (NYSERDA) co-funding a study, which was designed to conduct a comprehensive assessment of wind technology, and to perform a detailed technical study to evaluate the impact of large-scale integration of wind generation on the NYPS. The study was conducted by GE Power System Energy Consulting in fall of 2003 and completed by the end of 2004 (i.e., "the 2004 Study").

The overall conclusion of that study was the expectation that the NYPS can reliably accommodate up to 10% penetration or 3,300 MW of wind generation with only minor adjustments and extensions to its existing planning, operation, and reliability practices – e.g., forecasting of wind plant output. Also, the finding that no major issues were found in the aggregate does not mean that the potential for significant local interconnection issues or engineering challenges specific to particular site would not be encountered. Such issues would need to be identified through the NYISO's interconnection and electric system planning processes. In addition, the NYISO will continue to evolve its operating and interconnection requirements to implement best practices.

Since the completion of the NYISO/NYSERDA wind study, a number of the recommendations contained in the report have been adopted such as a low voltage ride through standard and a centralized forecasting service for wind plants. Installed nameplate wind generation has now grown to in excess of 1,200 MW and the NYISO interconnection queue significantly exceeds the 3,300 MW that was studied in the 2004 Study. In addition, the cap on eligible wind generation exempt from under generation penalties and eligible to be fully compensated for over-generation was increased from 1,000 MW to 3,300 MW. Finally, the State of New York has increased its RPS standard to 30% by 2015.

3. Wind Plant Integration – Issues

As a result of these changing conditions and ongoing wind integration issues, the NYISO committed to study the impact of wind generation beyond 3,300 MW. As part of the study process the NYISO identified a set of issues that need to be addressed in order to continue the orderly and reliable integration of continuing growth in wind generation into the NYCA power grid and market operations. These issues include the following:

Transmission: Transmission plays a critical role in the large scale integration of variable generation. A significant amount of new transmission and/or enhanced utilization of existing transmission capability will be needed over the next several years to accommodate and integrate higher levels of wind generation.

System Flexibility: The bulk power system will experience higher magnitude ramping events and to accommodate the increased variability and uncertainty of variable generation the system will need to commit proportionately more dispatchable resources to maintain system flexibility. The resource planning and development frameworks must ensure that the bulk power system has the necessary quantity of flexible supply and demand resources necessary to accommodate generation – e.g., storage capability or off-peak load such as plug-in hybrid electric vehicles. Markets, pricing mechanisms and interconnection standards need to provide signals about the characteristics that are valued both to existing generators and to entities that are planning for new generation.

Operator Awareness and Practices: Enhancements are required to existing operator practices, techniques and decision support tools to increase the operator awareness and to enable the operation of the future bulk power systems with large scale penetration of wind generation. Wind generation must be visible to[4] and controllable by the system operator similar to any other power plant to allow the system operator to maintain reliability. Based on current experience with operating wind plants the NYISO has already developed a FERC approved wind resource management proposal which makes wind plants subject to dispatch signals when system constraints exist.

Forecasting: Short term forecasting techniques used for real time operation must be enhanced to more accurately predict the magnitude and phase (i.e. timing) of wind generation plant output. One area needing increased attention is being able to predict extreme weather events that could result in the rapid loss of wind generation – e.g., “high-speed wind cutout”.

Wind Generation Plant Performance and Standards: Interconnection and generating plant standards must be enhanced to ensure that variable generating plant design and performance contribute to reliable operation of the power system.

System Models: Improved component model development, validation and standardization for all wind technologies are also required, especially for stability and transient analysis.

[4] The NYISO interconnection standards already require wind plants to be visible to system operators.

4. Study Tasks and Process

The study of wind penetrations in excess of 3,300 MW resulted in the following tasks:

Task 1: Develop wind generator penetration scenarios for selected study years including MW output profile and MW load profile.

Task 2: Develop and implement performance monitoring processes for operating wind generators.

Task 3: Update the review of the European experience conducted for the 2004 study with currently existing wind plants, and review the experiences and studies for wind plants in other regions of the US and Canada.

Task 4: Study the potential impacts on system operations of wind generators at various future levels of installed MW for the selected study years as it relates to regulation requirements and the overall impact on ramping.

Task 5: Evaluate the impact of the higher penetration of wind generation from a system planning perspective – including the evaluation of transmission limitations – by identifying specific transmission constraints (limiting element/contingency) for each project (or group of projects).

Task 6: Evaluate the impact of the higher penetration of wind generation on the overall system energy production by fuel types, locational based marginal prices (LBMP), congestion cost, operating reserves, regulation requirements, and load following requirements.

Task 7: Identify the impact of transmission constraints on wind energy that is not deliverable (i.e., “bottled”) because of the transmission constraints and identify possible upgrades for the limiting elements/transmission facilities.

The technical analysis required by the study task includes a set of sequential steps that are needed to successfully conduct a comprehensive analysis of integrating wind into the grid as a function of penetration level. In addition to the traditional planning analysis and economic assessments, the integration of a variable generation resources requires the assessment of operational issues as well. Operational analyses in conjunction with traditional planning assessments are necessary to fully understand the overall technical implication and potential cost associated with integrating variable generation resources. This process includes the following steps:

Step 1: A determination of the interconnection point of the resources and potential output

Step 2: A thorough assessment of the transmission system to determine the contingencies and constraints that could adversely impact wind

Step 3: A statistical analysis of the interaction of load and wind as measured by the net load to determine the impact of variable wind resources on overall system variability and operational requirements

Step 4: Dispatch simulation with a production cost tool to determine the amount of wind that will be constrained off and the impact of wind on the overall dispatchablility such as plant commitment and economics of the system

Step 5: An identification and rank ordering of the transmission constraints that impact the dispatchablility of wind

Step 6: Development of transmission upgrades to relieve wind constraints for the various penetration levels of wind

Step 7: Redo step 4 with upgrades and needed operational adjustments determined in step 3 to determine the full impact

Step 8: Conduct a dynamic assessment to determine if the planned system with the higher levels of wind will satisfy stability criteria

Step 9: Conduct loss-of-load-expectation (LOLE) analysis to determine the impact of installed wind on system load carrying capability or reserve margin requirements.

5. Wind Study Results

5.1. Results for Task 1 - Study Assumptions:

This task resulted in three study years being selected. They are 2011, a near-in year; 2013 which is the target year of the 25% RPS; and 2018, which is the tenth year of the 2009 reliability planning cycle, and is also the first year of the Eastern Interconnection Wind Integration study being conducted by the National Renewable Energy Lab (NREL). The starting point or base assumptions for the wind study was the base case for the 2009 Comprehensive Reliability Plan[5] (CRP) for the transmission analysis. The starting point for the production cost simulations was the assumptions in the 2009 Congestion Assessment and Resource Integration Study[6] (CARIS).

Section 4.3.1 of the CARIS report presents the New York Control Area transfer limits that were used for the study including a Central East limit of 2,600 MW. The wind study used the nominal planning limit of 2,800 MW. Section 4.4 of the CARIS report presents the fuel costs assumptions that were used in the production costs simulations which was the GridView modeling tool used for the CARIS study. Section 4.5 of the CARIS report presents the emission costs that were used in the study. The cost for CO_2 or green house gas emissions are approximately $3.50 per ton in 2009 and increase to approximately $6.00 per ton in 2018, with 2013 at approximately $5.00 per ton.

For each of the years, two levels or scenarios of installed nameplate wind plant were developed. They are: 1) 3,500 MWs and 4,250 MWs for 2011 which represents approximately 10% and 12% of the projected peak for that year while 4,250 MWs would supply 6.5% of the forecast energy at a 30% capacity factor; 2) 4,250 MWs and 6,000 MWs for 2013 with 6,000 MWs equal to 17% of the projected peak for that year and 8.9% of forecast energy at a 30% capacity factor; and 3) 6,000 MWs and 8,000 MWs for 2018 while 8,000 MWs of wind is equal to 22.4% of the projected peak for that year and 11.6% of forecast energy at 30% capacity factor. AWS Truepower (formerly know as AWS Truewind) who is the contractor for the wind forecasting service, as well as a contractor to NREL for the Eastern Interconnection Wind Integration study, provided the wind output profiles required for the study.

5.2. Results for Task 2 - Wind Plant Performance Monitoring:

One of the observations made in the initial wind study was that much could be learned from operating wind plants as they came on line. To that end, the NYISO developed a reporting process for tracking the performance of operating wind plants. The report entitled: “Daily Wind Plant Performance Tracking Report” tracks the performance of wind plants on a daily basis for key metrics such as maximum coincident wind plant output, total output at the time of the system peak, Mwh generated, capacity factor, etc. Appendix A-1 contains the daily summary report for 2009.

Besides daily tracking of wind plant performance, the NYISO has experienced and analyzed rare events such as high-speed cutout which is the result of wind conditions that exceed the capability of the wind turbines causing them to shut down rapidly to protect the equipment. Wind plants can also ramp up quickly as the wind speed picks up suddenly. Wind plants may ramp up quickly as a thunder storm approaches a plant site and then shut down as wind exceeds the capability of the equipment. Figure 5.1 is an example of a high-speed cutout event that NYISO operations observed on June 10, 2008. The figure shows how a front containing thunderstorms moved from west to east affecting wind plants at different locations on the system. Wind plant output is

[5] http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP__FINAL_5-19-09.pdf
[6] http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/CARIS_Final_Report_1-19-10.pdf

expressed as a percent of nameplate. For the first set of plants (red line) to encounter the front, the plants ramp up preceding the cutouts from 26% of nameplate to 61% of nameplate over 30 minutes and then ramp downs from cutouts to 5% of nameplate over 10 minutes. After the storm passes, the plants ramp back up to 82% of nameplate over 45 minutes. A similar pattern is observed later for the plants further to the east (green line).

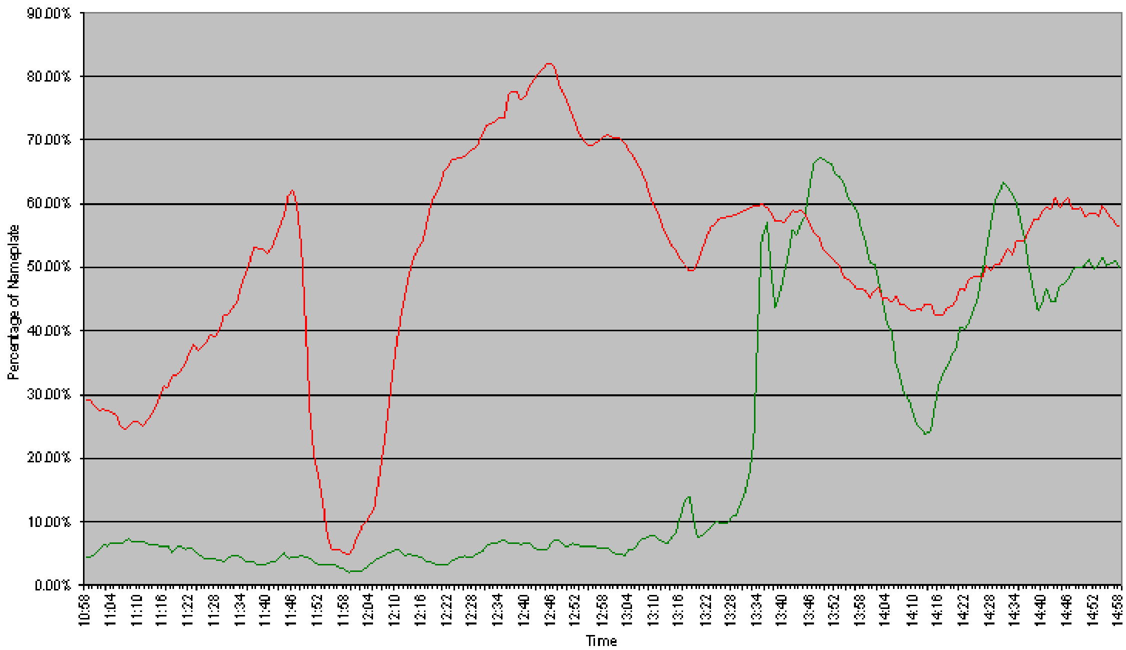


Figure 5.1: High-Speed Cutout Event approx. 12 noon on 6/10/08

In addition, the NYISO has observed the ability of wind plants to adjust the level of their output rapidly in response to changing system conditions which result in price changes. These operating experiences to date indicate a need to communicate dispatch commands to the wind plant operators on an as needed basis to maintain reliability especially as the amount of installed wind plant MWs increased. Experience with existing wind plants resulted in the NYISO moving forward with a resource management initiative to extend its market-based Security Constrained Economic Dispatch (SCED) systems to wind plants.

The integration of increased levels of wind will be facilitated by using the NYISO's market signals (e.g. location-based marginal prices) and the economic offers submitted by the generation resources, including wind plants, to address reliability issues rather than relying upon manual intervention by operators.

Based on the offers submitted by each wind plant and other resources, SCED will determine the most economic mix of resources to meet real-time security constraints. Allowing wind plants to indicate their economic willingness to operate reduces the need for the NYISO or local system operators to take less efficient, out-of-market actions to protect the reliability of the system.

This results in better utilization of wind plant output while maintaining a secure, reliable system and more accurate LBMP signals.

This wind on dispatch initiative was developed in conjunction with stakeholders, approved by the Federal Energy Regulatory Commission, and has now been implemented.

5.3. Results for Task 3 - European, US and Canada Experience with Wind Plants:

The purpose of Task 3 was review of the European experience with existing wind plants and review the experiences and studies for wind plants in other regions of the US and Canada that have been conducted since the 2004 Study. Europe is the region of the world that has highest penetration of wind. The NYISO contracted with Dr. Thomas Ackermann of Energynautics GmbH to provide a report of Europe's most recent operating experience with wind. Also, the NYISO reviewed the most recent study work from California, Texas and the Province of Ontario. In addition, the NYISO is participating in the North American Electric Reliability Councils, Inc. (NERC) Integration of Variable Generation Task Force (IVGTF) as well as what is known as the "Eastern Interconnection Wind Integration Study". This study includes Department of Energy/NREL, MISO (study lead), NYISO, PJM, SPP, and TVA.

The primary findings of the report prepared by Dr. Ackerman are as follows:

Europe shows that high/very high wind penetration levels are possible, but those high penetration levels are driven by energy policy (subsidies) and not economics for the most part. This also applies to power system integration issues.

Wind power can be successfully included in markets (Spain/UK).

Transmission helps to achieve benefits of aggregating large-scale wind power development and provides improved system balancing services. This is achieved by making better use of physically available transmission capacity and upgrading and expanding transmission systems. High wind penetrations may also require improvements in grid internal transmission capacity.

European regulators and Transmission System Operators (TSOs) have developed a willingness to learn and question existing rules as well as to adjust rules and regulations. In addition, most European countries have shown a flexibility to adjust their energy policy, rules and regulations depending on the technical and economical development in order to create a low-risk environment for renewable energy projects, without allowing windfall profits as it is very difficult to get all relevant regulatory details right at the first attempt. This flexibility for change has been based on a continuous dialogue between policy makers, regulators, network companies and the renewable energy lobby.

Both load and generation benefit from the statistics of large numbers as they are aggregated over larger geographical areas. Larger balancing areas make wind plant aggregation possible. The forecasting accuracy improves as the geographic scope of the forecast increases; due to the decrease in correlation of wind plant output with distance, the variability of the output decreases as more plants are aggregated. On a shorter-term time scale, this translates into a reduction in reserve requirements; on a longer-term time scale, it produces some smoothing effects on the capacity value. Larger balancing areas or coordination agreements with neighboring areas also give access to more balancing units such as hydro units and the ability to bank energy.

Integrating wind generation information into real-time system operations and with updated forecasts for the day-ahead operations will help manage the variability and forecast errors of wind power. Well-functioning hour-ahead and day-ahead markets including having wind plants respond to dispatch signals can help to more cost-effectively provide balancing energy required by the variable-output wind plants and maintain system security.

Appendix B-1 provides an expanded summary of Dr Ackermann's findings.

The overall conclusion from the California study sponsored by the California ISO (CAL-ISO) can best be summarized by the words of California ISO President & CEO Yakout Mansour: "The good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20% RPS, provided that existing generation remains available to provide back-up generation and essential reliability services. The cautionary news is the “provided” part of our conclusion.” Appendix B-2 provides an expanded summary of the CAL-ISO study.

The overall conclusion from the Texas study sponsored by the Electric Reliability Council of Texas (ERCOT) is that through 5,000 MW of wind generation capacity, approximately the level of wind capacity presently in ERCOT (on the order of 5% of the peak), wind generation has limited impact on the system. Its variability barely rises above the inherent variability caused by system loads. At 10,000 MW wind generation capacity, the impacts become more noticeable. By 15,000 MW (on the order of 20% of the peak), the operational issues posed by wind generation will become a significant focus in ERCOT system operations. However, the impacts can be addressed by existing technology and operational attention, without requiring any radical alteration of operations. Appendix B-3 provides an expanded summary of the ERCOT study.

The Ontario study was sponsored by the Ontario Power Authority (OPA). This study concluded that for all wind scenarios, the increase in hourly and multi-hourly variability, as measured by σ, due to wind is relatively small (not more than 10% for any scenario). From an hourly scheduling point of view, even 10,000 MW of wind would not push the envelope much further beyond the current operating point. However, the amount and magnitudes of extreme one-hour and multihour net-load changes are significantly greater with high wind penetration. With the addition of 10,000 MW of wind, the maximum one-hour net-load rise increases by 34%, and the maximum one-hour net-load drop increases by 30%. This data indicates that with large amounts of wind, much more one-hour ramping capability is needed for secure operation. Clearly the longest sustained ramping (up and down) occurs during the summer morning load rise and evening load decline periods. During these periods (and others) the units may need to ramp continually over three or more hours. For the year 2020 load with 10,000 MW of wind scenario, the maximum positive three-hour load-wind delta increases by 17% and the maximum negative three-hour delta increases by 33%. The detailed results clearly illustrate the fact that units will have to undergo sustained three-hour ramping more often, and ramp further with the addition of large amounts of wind. Appendix B-4 provides an expanded summary of the OPA study.

As noted above, the NYISO also participated in NERC’s Integration of Variable Generation Task Force. In December 2008 in anticipation of the growth of wind and other variable generation, NERC’s Planning and Operating Committees created the Integration of Variable Generation Task Force charged with preparing a report to include: 1) philosophical and technical considerations for integrating variable resources into the Interconnection, and 2) specific recommendations for practices and requirements, including reliability standards, that cover the planning, operations planning, and real-time operating timeframes.

The goals of this report were to:

Raise industry awareness and the understanding of characteristics of variable generation

Raise industry awareness and the understanding of the challenges associated with large scale integration of variable generation

Investigate the impacts on traditional approaches used by system planners and operators to plan, design and operate the power system

Scan NERC Standards, FERC rules and business practices to identify possible gaps and future requirements to ensure bulk power system reliability in light of large scale integration of variable resource

The final document was issued on April 16, 2009 and is available on the NERC website[7].

In conclusion, the primary insights that can be drawn from the review of the European and other studies and the NERC draft report are as follows:

[7] http://www.nerc.com/files/IVGTF_Report_041609.pdf

Higher levels of installed wind generation above the 3,300 MW from a system operation perspective are feasible.

Achieving a higher level of wind penetration will most likely require the implementation of enhancements to and extension of existing operating protocols, procedures and reliability standards.

The major areas of ongoing concern that are common across all regions tend to focus on the following questions:

Will there be sufficient transmission infrastructure to integrate the higher penetrations of wind?

Will sufficient resources be available when the higher penetration of wind generation are achieved to provide the operational flexibility that will be needed with higher penetration of variable generation?

Validation of wind turbine models needed for system studies.

5.4. Results for Task 4 - Assessing the Impact of Wind Plants on System Operations:

5.4.1. Introduction

The focus of Task 4 is to study the impacts on system operations of the penetration of installed wind plants above 3,300 MWs. The impact of increasing wind penetration from its current installed nameplate of 1,274 MW up to 8,000 MW on such operational parameters as regulation requirements, load following, ramping and operating reserves were evaluated. Power systems are dynamic, existing in a continuously changing environment, and are impacted by factors that change from moments-to-seconds, seconds-to-minutes, minutes-to-hours, seasonally and year-to-year. In the various time frames of operation, balance must be maintained between the load on the system and the available generation. In the very short timeframe (seconds-to-minutes), bulk power system reliability is almost entirely maintained by automatic equipment and control systems such as automatic generation control (AGC). In the intermediate to longer timeframes system operators and operational planners are the primary keys to maintaining system reliability. Figure 5.2 displays the various timescales that impact power systems, the operating and planning processes they impact and the associated issues that need to be addressed.

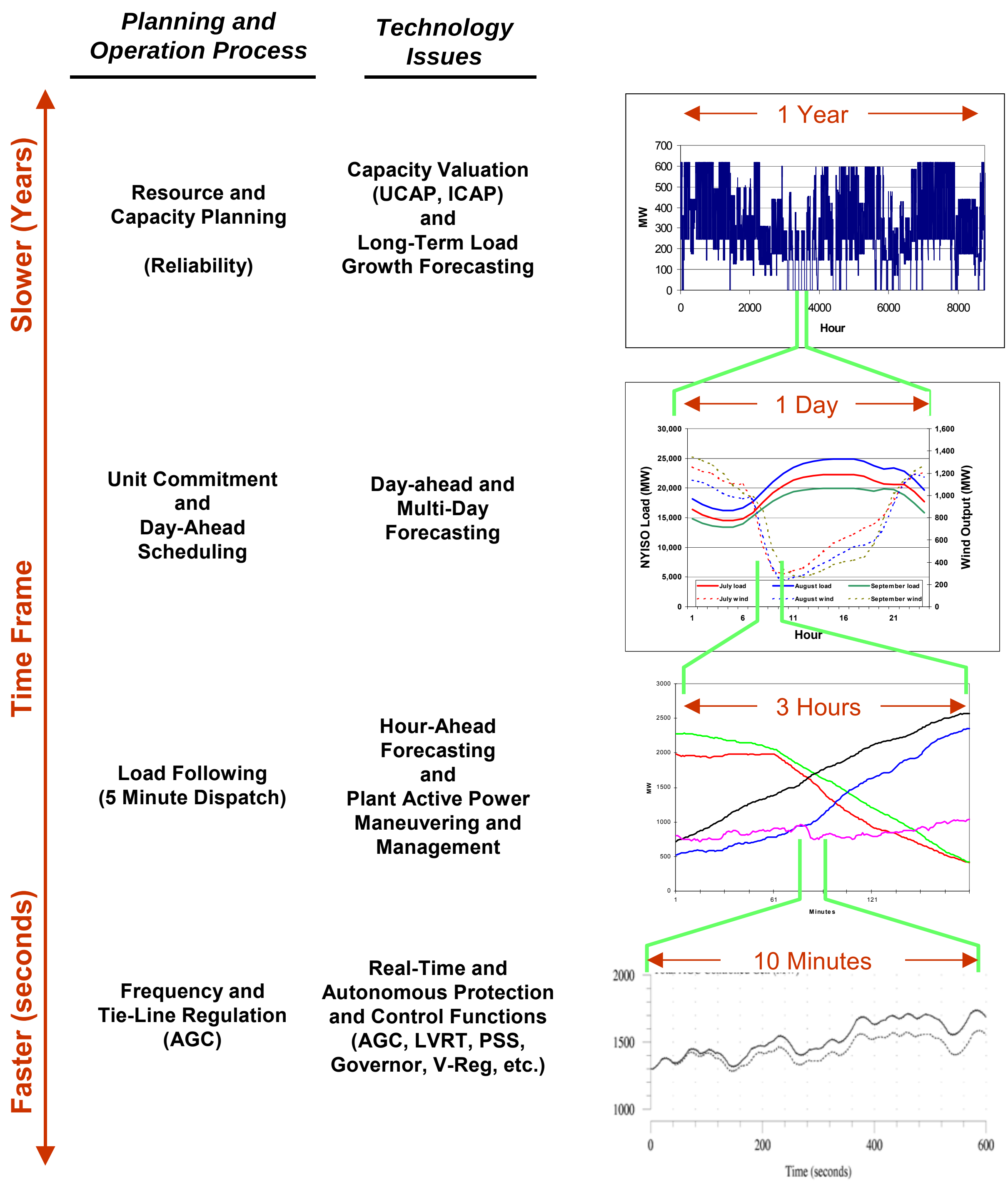


Figure 5.2: Power System Time Scales

The fact that the load is constantly changing means that its variability must first be understood in order to assess the impact of another variable element, (such as wind), on system operation. Statistics is an extremely useful tool for understanding and describing variation in data. The analysis of system variability for various time scales from minutes to hours is being conducted to assess the impact on such operating parameters as regulation, load following, operating reserves, ramping, and scheduling. Figure 5.2 presents the various time scales and the technology issues that are important in that time frame.

AWS Truepower developed wind profiles based on 2004 through 2006 wind data for approximately 35 sites in NY. Utilizing operating wind plants and proposed projects in the interconnection queue the NYISO then developed simulated outputs for wind plants ranging from an installed base of nameplate wind of 3,500 MW up to 8,000 MW of installed nameplate wind. The intermediate steps were nominally 4,250 MW and 6,000 MW. The wind plants from the NYISO's interconnection queue that are included in the study are listed in Table 5-1.

Table 5-1: List of Wind Plant Units

Units that Compose the 1275 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
I/S	Altona Windfield	99.0	D
I/S	Bliss Windfield	100.5	A
I/S	Canandaigua II	42.5	C
I/S	Canandaigua Wind Farm	82.5	C
I/S	Chateaugay Windpark	106.5	D
I/S	Clinton Windfield	100.5	D
I/S	Ellenburg Windfield	81.0	D
I/S	Fenner Wind Power	30.0	C
I/S	High Sheldon Windfarm	113.0	C
I/S	Madison Wind Power	11.6	E
I/S	Maple Ridge 1	231.0	E
I/S	Maple Ridge 2	90.7	E
I/S	Munnsville Wind Power	34.5	E
I/S	Steel Winds	20.0	A
I/S	Wethersfield 230kV	126.0	C
I/S	Wethersfield Wind Power	6.6	B

Units Added to Create the 4250 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
113	Prattsburgh Wind Park	55.5	C
119	Prattsburgh Wind Farm	79.5	C
152	Moresville Energy Center	129.0	E
155	Canisteo Hills Windfarm	148.5	C
156	Fairfield Wind Project	120.0	E
157	Orion Energy NY I	100	E
160	Jericho Rise Wind Farm	101.2	D
161	Marble River Wind Farm	88.2	D
166	St. Lawrence Wind Farm	130.0	E
168	Dairy Hills Wind Farm	120.0	C
169	Alabama Ledge Wind Farm	79.2	B
171	Marble River II Wind Farm	140.7	D
182	Howard Wind	62.5	C
186	Jordanville Wind	136.0	E
189	Clayton Wind	126.0	E
197	Tug Hill	78.0	E
198	New Grange Wind Farm	79.9	A

203	GenWy Wind Farm	478.5	A
207	Cape Vincent	210.0	E
220	Armenia Mountain I	175.0	C
221	Armenia Mountain II	75.0	C
222	Ball Hill Windpark	99	A
234	Steel Winds II	60	A
237	Allegany Windfield	79	A

Units Added to Create the 6000 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
150	Cherry Valley Wind Power	70	F
178	Allegany Wind	79.0	A
179	Cherry Hill Windpark	102	D
187	North Slope Wind	109.5	D
215	Noble Burke Windpower	120	D
217	Cherry Flats	90	C
227	Orleans Wind	120	B
236	Dean Wind	150	C
238	Tonawanda Creek Wind	75	B
239	Western Door Wind	100	C
240	Farmersville Windpark	100	A
246	Dutch Gap Wind	250	E
254	Ripley-Westfield Wind	124.8	A
256	Niagara Shore Wind	70.5	A
263	Stony Creek Wind Farm	142.5	C
241	Chateaugay II Windpark	19.5	D

Units Added to Create the 8000 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
270	Hounsfield Wind	268.8	C
282	Concord Wind	101.2	A
285	Machias I	79.2	A
297	Ashford Wind	19.9	A
298	Leicester Wind	57	B
301	Hamlin Wind Farm	80	B
327	Offshore Wind	1400	J, K

Summary of Nameplate Rating by Case for each Zone (MW)

Case	A	B	C	D	E	F	J, K	Total
1275	121	7	394	387	368			1276
4250	917	86	1110	717	1397			4227
6000	1291	281	1593	1068	1647	70		5949
8000	1492	418	1861	1068	1647	70	1400	7955

The simulations were done based on 2005 and 2006 wind data. The AWS site closest to the existing wind or proposed wind plant site was utilized for developing a specific output profile for that wind plant. Output profiles based on 2005 and 2006 wind data were developed for each wind plant. The first 1,500 MW of wind was simulated with wind turbines with a hub height of 80 meters and balance with a hub height of 100 meters. Simulated wind plant output was developed for one minute, ten minute and one hour for selected sites in NY. Load profiles were developed internally.

Figure 5.3 shows the hourly simulations for 8,000 MW of New York wind plants based on 2006 wind data. Note the variability of the aggregate wind plant output which swings between 90% of nameplate and close to zero. The figure also contains the thirty day, or 720 hour, moving average which shows the seasonality of wind with the highest energy production during the winter capability period and the lowest being during the summer capability period (hours 2880 – 7269).

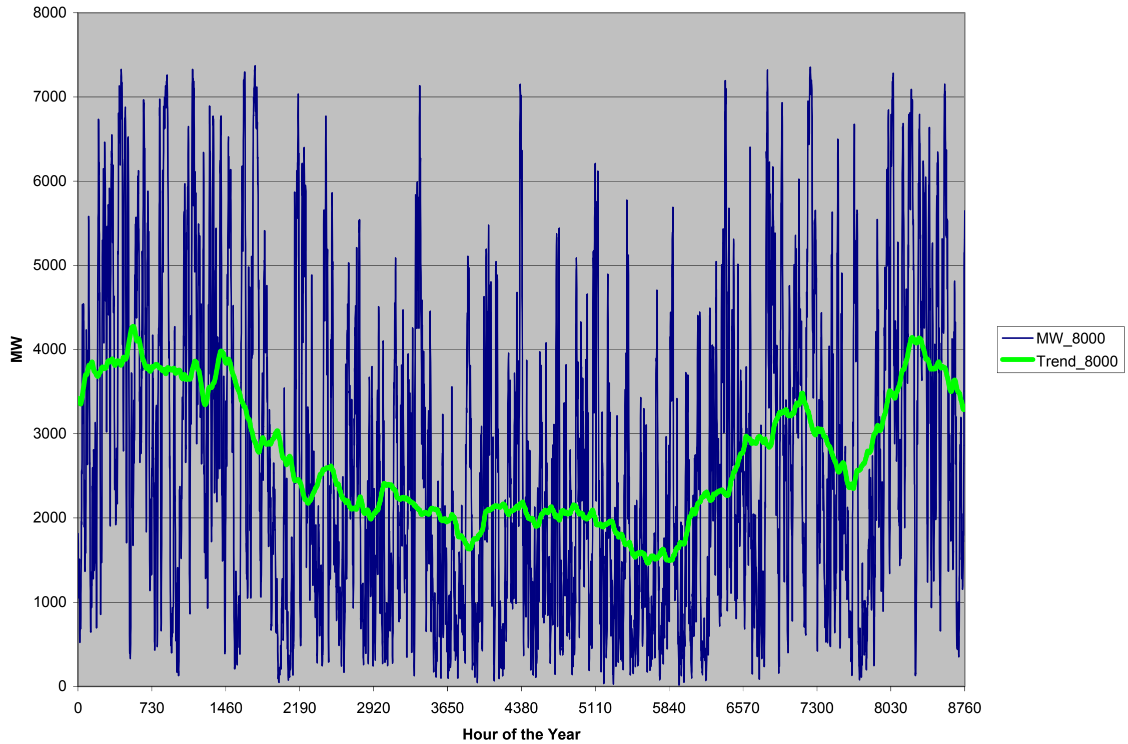


Figure 5.3: Hourly Wind Output for 8,000 MW of Wind

The AWS data is available from NREL at http://wind.nrel.gov/public/EWITS/. Load models for each time frame were also developed.

5.4.2. The Critical Importance of Net Load

Net load is defined as the aggregate customer load demand minus the aggregate variable generation output. Why is net load important? It is important because variable generation has more in common with system electrical demand (load) than conventional generation resources, as both are:

Cyclic on an annual (seasonal) basis, and a diurnal (daily) basis

Subject to random short-term variations around the multi-hour trends

Limited controllability (i.e., limited dispatchablility)

Subject to deviations from predicted day-ahead behavior

Mutually dependent on prevailing weather conditions

As a result, determining the impacts of variable generation on bulk power system operations and planning cannot be evaluated by examining wind generation output characteristics, such as its variability and predictability, independently from the simultaneous behavior of the load. Thus, analysis of wind variation independent of load variation is inadequate and inappropriate to determine impacts of variable generation on the need for flexibility. Operationally, the dispatchable generation output must conform to the characteristics of the net load.

How does variable generation interact with load to affect the variability of net load? The inherent variability and imperfect predictability of variable generation adds to the variability and prediction errors of system load. Experience has shown that some of the variation in load and wind output cancel each other in a combined series. In other words, given synchronized load and wind generation time series, the net variability of load-wind over a time period is less than the sum of the variability of the individual series over the same time period. In addition, the variabilities cannot simply be combined as if they are independently random, as they are both affected by the common factor of the weather. Nor can they be added algebraically because the correlation is only partial and the coefficient can be either positive or negative, or vary in sign with time or location of the wind resource.

The result is that the net-load is considerably more variable than the load by itself which increases as the amount of variable generation increases. It is the net-load that conventional generation will have to respond to. This will result in a need for greater flexibility from the conventional supply resources. This will translate into a greater need for regulation, ramping, and load following capability in real time operations. These requirements will need to be accounted for in the planning timeframe as well.

5.4.3. Net Load Variability Characterization

Net load (Load minus Wind) is the amount of generation required from dispatchable units. This section focuses on the variability of net-load rather than wind generation in isolation because experience has shown that some of the variation in load and wind output cancel each other in a combined series. In other words, given synchronized load and wind generation time series, the net variability of load-wind over a time period is less than the sum of the variability of the individual series over the same time period.

5.4.4. Measuring Variability

The variability of net load in different timeframes impacts various aspects of bulk power system operation. Implications for regulation requirements, ramp and range considerations, and operating reserves issues can be drawn from an analysis of net load variability in the 1-, 5-, 15-, 30-, and 60-minute timeframes, depending on the ancillary service definitions and market rules. This section will focus on the statistical analysis of load and net load variability in the various timeframes. In this section several terms are used to characterize the load and net load variability. They include:

Delta (Δ) – The incremental change in a variable such as a period-to-period ramp rate

Sigma (σ) – The standard deviation of a dataset which is a measure of how dispersed observations are, relative to the mean (μ)

Since deltas can be positive or negative depending on the slope of the series at a point in time, the average of the deltas is somewhat meaningless. In fact, for a series of a day or longer, the mean of the deltas is zero or near zero. The standard deviation of the deltas, however, is a good indication of how much the series changes from period-to-period; therefore sigma of the deltas is used as a measure of variability in this study. If the deltas are normally distributed (a rational assumption based on experience) then sigma relates to the proportion of deltas within a certain distance of the mean μ as shown in Figure 5.4.

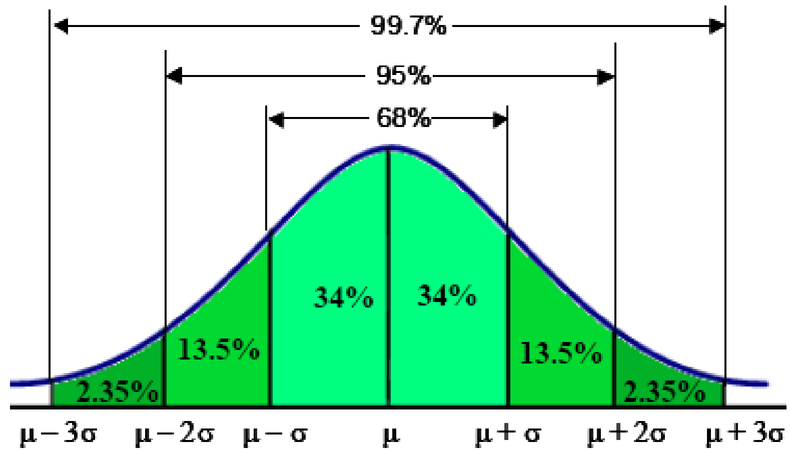


Figure 5.4: Normal Distribution

The sigma (σ) of the deltas (Δ) of the net load for the various time domains and can be summarized in many different ways. For instance, the sigma can be calculated hourly, in groups of hours, day of week, monthly, annually, etc. For the NYCA analysis, the σ for the various time domains was calculated by hour, groups of hours, all-days, weekdays, Saturday, Sunday, monthly, and annually. The annual numbers are useful in showing macro trends while the monthly numbers are useful in focusing the analysis. Hourly numbers and groupings are useful for assessing impacts on system operations.

The key driver for net load variability is the time domain relationship between load and wind plant output. Wind can amplify operationally challenging periods. For instance, wind is generally dropping off during the morning load rise which amplifies the morning ramp up requirements. Likewise wind is usually ramping up when the load is dropping off which amplifies the down ramp. How wind interacts with load is the important factor in considering the impact of wind generation on the need for ancillary services, especially regulation, which is discussed later in this report.

The following figures abstracted from the wind simulations for New York clearly demonstrate the time domain interaction of wind and load as described above. Figure 5.5 and 5.6 is a simulation for 2013 for the July system peak load day with 6,000 MW of installed nameplate wind. Figure 5.5 includes the wind as well as the load and net load while Figure 5.6 presents the load and net load without the wind.

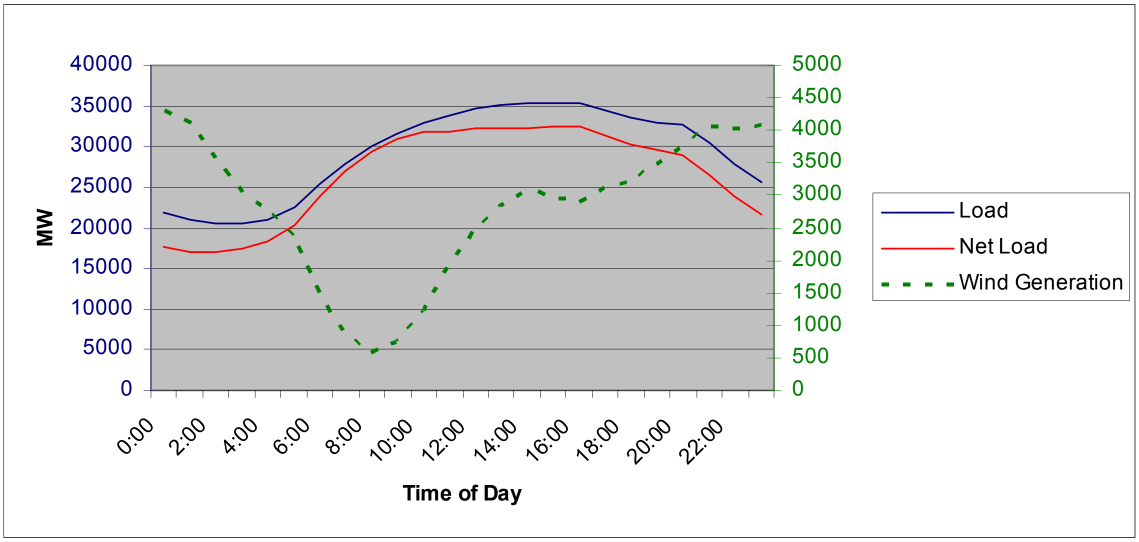


Figure 5.5: Load, Net Load and Wind for the Peak Day of July 2013 with 6,000 MW of Wind

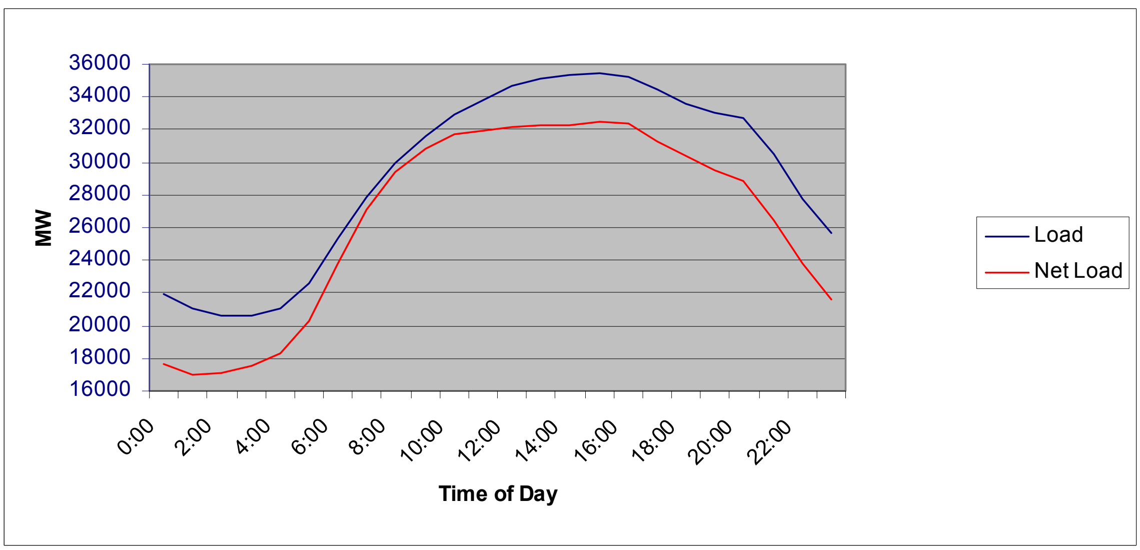


Figure 5.6: Load and Net Load for the Peak Day of July 2013 with 6,000 MW of Wind

A number of observations can be extracted from these figures. The first is the confirmation of the above discussion which is wind is generally dropping off when load is ramping up and when the load is ramping down the wind is ramping up. The result is the morning load ramp starting earlier and being steeper, and the evening load drop starting a little later and being steeper. Another observation that is not as apparent with this graphic but which is demonstrated with the next graphic, is that change from the MW difference between the night-time net load minimum to the day-time net daily peak load are generally much greater. Finally, this graphic does show a phenomenon that wasn't present in the initial study and is somewhat unique to New York which is the afternoon or secondary peak in wind plant output. The result is that NY's wind plant output has demonstrated higher coincidence with peak loads than the first study found, especially for the peak summer months.

The final observation that can be made is that the change in the night time net-load minimum will be lower than load by itself as well as an increase in the MW delta from the daily net-load minimum to the daily net-load peak. Table 5-2 below presents how the various wind scenarios will impact the net minimum load with no wind curtailment while Table 5-3 presents the minimum to peak maximum increases for summer and winter in 2018. Also, Figure 5.7 and Figure 5.8 present load and net load for the simulated 2018 summer and winter peak weeks to demonstrate visually the resultant net load which the dispatchable generation would have to follow. The Tables and Exhibit provide simulation results that show that the nighttime net-load minimums will be much lower than load by itself and the amount of movement in dispatchable generation (daily ramp up) that will be required to follow the load from the night-time low to the daily peak will also increase significantly.

Table 5-2: Simulated Minimum Loads and Minimum Net-Loads

Study Year	Load No Wind (MW)	Low Wind Scenario[1] (MW)	High Wind Scenario[2] (MW)
2008	10,790		
2011	12,618	10,297	9,692
2013	12,937	10,023	8,560
2018	13,721	9,398	7,574

1) 3,500 MW in 2011, 4,250 MW in 2013 and 6,000 MW in 2018
2) 4,250 MW in 2011, 6,000 MW in 2013 and 8,000 MW in 2018

Table 5-3: Trough to Peak Maximum Increases for Summer and Winter 2018

Load Metric\Season	Summer 2018		Winter 2018	
	Date	MW	Date	MW
Peak Load	17-Jul	37102	8-Dec	28231
Max Load Change Trough-Peak	17-Jul	15627	18-Dec	11389
Max Net Load Change Trough-Peak	18-Jul	17464	11-Dec	14734

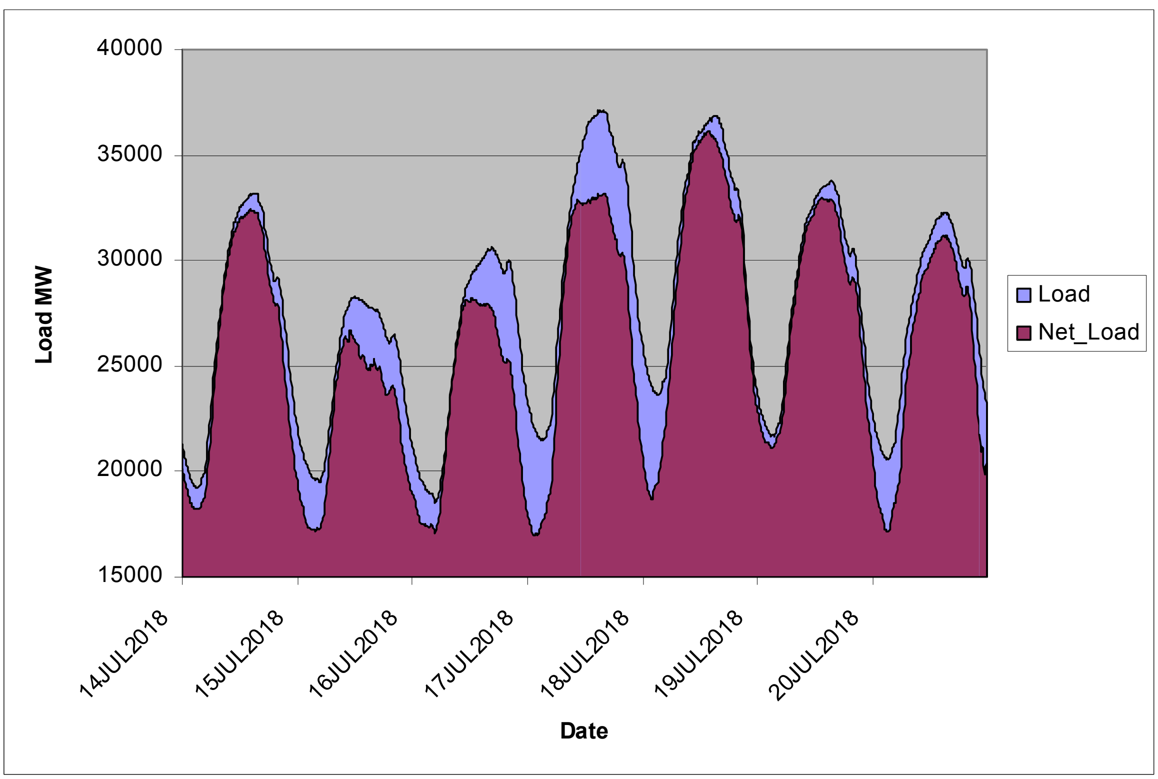


Figure 5.7: Load and Net Load for the Simulated 2018 Summer Peak Week

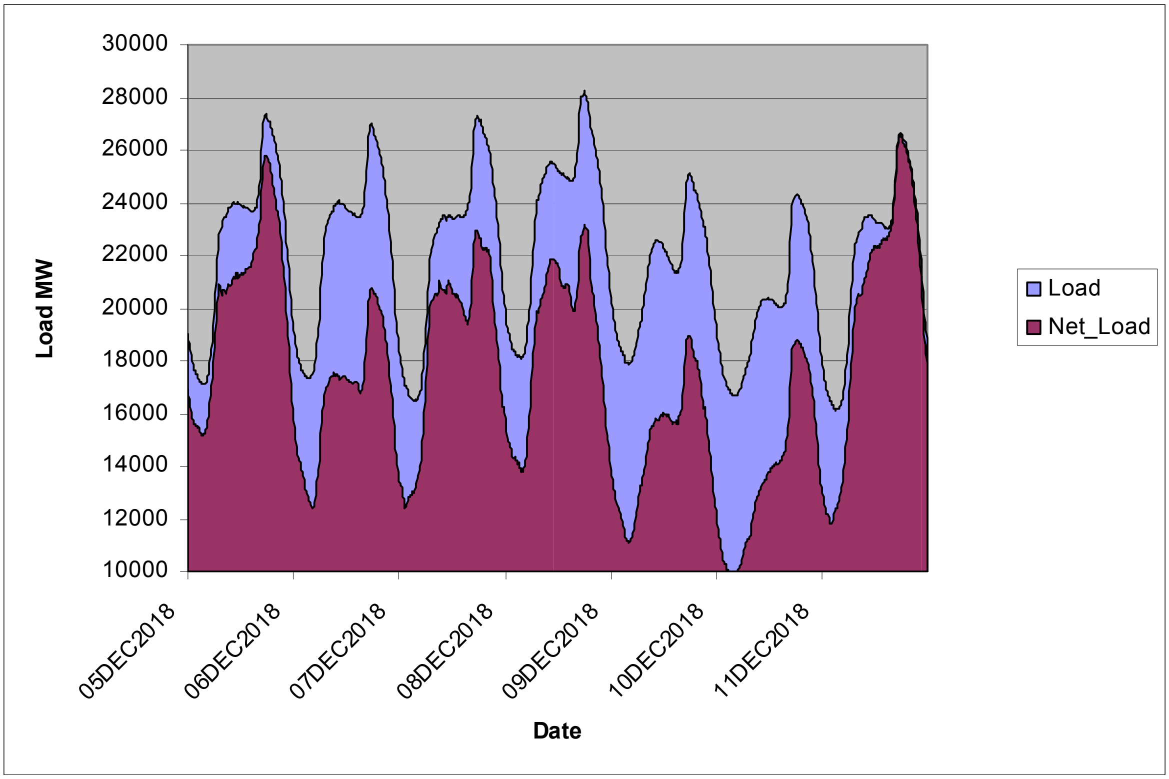


Figure 5.8: Load and Net Load for the Simulated 2018 Winter Peak Week

5.4.5. Impact of Wind on System Net-Load Variability

Simulations of wind plant output for total installed nameplate wind plant range between 3,500 MW and 8,000 MW for the years 2011, 2013, and 2018. Wind plant output simulations were conducted based on two different weather and load shape years which were 2005 and 2006 to determine the impact of variable wind generation on the net-load. The input and output data created for this analysis totaled in excess of 2 gigabytes. This presented a significant challenge in terms of presenting the results without overwhelming the reader with a significant volume of data but yet presenting the salient points. As presented above, the timescales for the all power system operational processes impacted by wind plants range from less than seconds to minutes, days, and longer.

How does variable generation interact with load to affect the variability of net load? Variations in load and wind output can cancel each other in a combined series. In other words, given synchronized load and wind generation time series, the net variability of load plus wind over a time period is less than the sum of the variability of the individual series over the same time period. In addition, the variability of each cannot simply be combined as if they are independently random, as they are both affected by the common factor of the weather.

The overall outcome is that system variability as measured by the sigma of the net-load deltas increases in all time frames. Figure 5.9 below displays the deltas of the load and net-load for 60 minutes. This is for 8,000 MW of wind and the 2018 load forecast used in this study. The result is generally what is observed in all timeframes. It is also the result that has been in observed in other studies of wind integration. The net-load which is the green or darker bars in the figure has higher variability than the load which has a distribution which is more peaked and less dispersed.

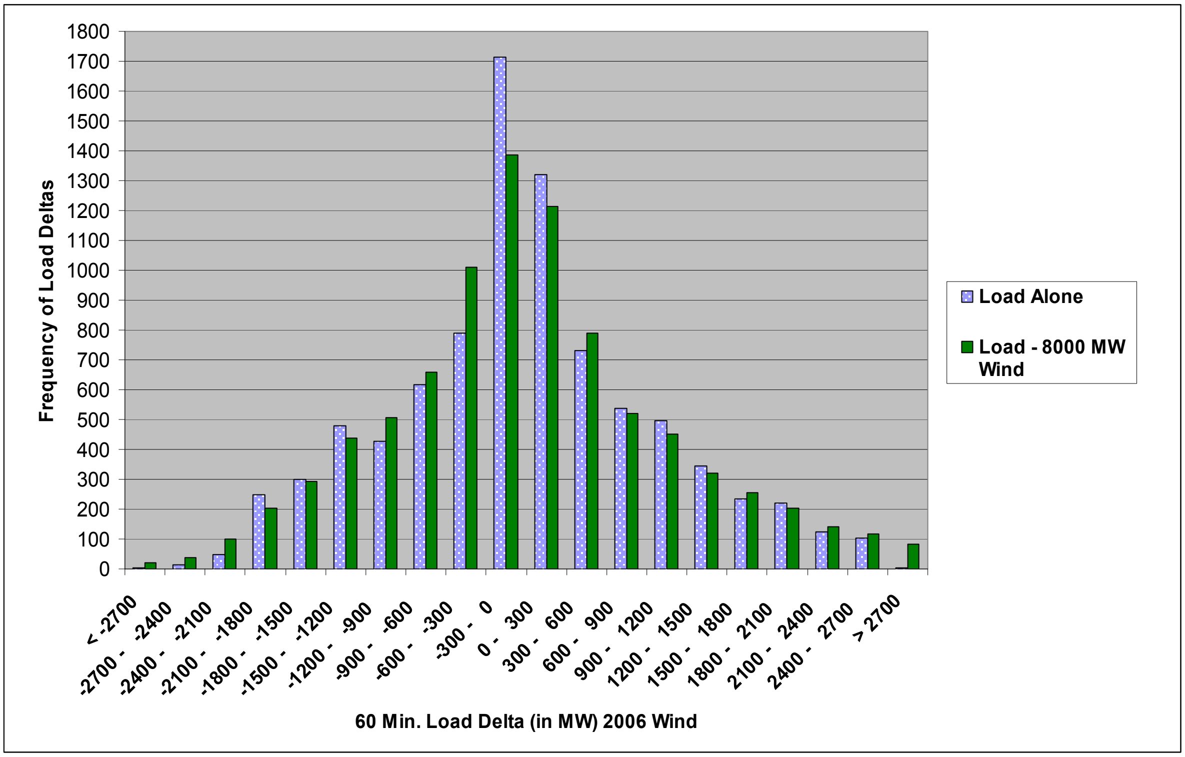


Figure 5.9: Distribution of 60-minute Deltas for Load and Net Load with 8 GW of Wind

As can be seen in Figure 5.9, the frequency of occurrence of the net-load deltas when compared to the load deltas decreases for deltas around zero where wind and load cancel each other. The frequency of higher magnitude net-load delta increases when compared to the load deltas for deltas nearer the extremes of the distribution where wind and load are additive. The result is that the net load is considerably more variable than the load by itself and increases as the amount of variable generation increases.

Given that the variable and uncertain nature of wind plant output results in net-loads that are more variable than the load by itself, the next factor to explore is how does increasing wind plant penetration impact overall net-load variability as measured by the net load deltas? Does it increase linearly with increasing wind plant penetration or exponentially?

To assess this issue a summary of annual sigma of load (without wind) and net-load for various penetrations of wind plants is presented for the 1-minute, 5-minute and 60-minute timeframes. The annual sigma provides a macro overview of how this statistical parameter changes with increasing load and wind penetration. These timeframes are presented because they incorporate the timeframes important to operational processes such as the automatic generation control (AGC), the five minute dispatch cycle and longer term ramping requirements. In the five minute timeframe, the operational burden imposed by wind will certainly translate into more ramp and range requirements as well as potentially increasing regulation requirement. The one-hour timeframe gives a good indication of the longer term ramping requirements that will be required with wind because random variations have less impact in the longer timeframes. Table 5-4 presents the simulated results for how the annual sigma changes with increases in wind penetration and load growth.

Table 5-4: Annual Load/Net-Load Δ σ by Timeframes, Load Levels and Wind Penetration

Case	1-min. Δ Sigma MW	Percent Increase With Wind	5-min. Δ Sigma MW	Percent Increase With Wind	60-min. Δ Sigma MW	Percent Increase With Wind
Load Alone 2011	36.6		85.4		895.9	
Net Load 3500 MW of Wind	37.6	2.8%	89.1	4.4%	916.2	2.3%
Net Load 4250 MW of Wind	37.9	3.5%	90.3	5.7%	924.2	3.2%
Load Alone 2013	37.5		87.5		918.5	
Net Load 4250 MW of Wind	38.8	3.4%	92.3	5.5%	946.4	3.0%
Net Load 6000 MW of Wind	39.6	5.6%	95.9	9.6%	967.9	5.4%
Load Alone 2018	39.8		92.8		973.8	
Net Load 6000 MW of Wind	41.8	5.0%	100.8	8.6%	1021.5	4.9%
Net Load 8000 MW of Wind	42.8	7.5%	104.8	12.9%	1039.6	6.8%

As expected, overall annual net-load sigma/variability increases as wind generation penetration increases. The increase appears to be linear with a very gradual slope for the penetrations studied which ranged from 10% of peak load up to 21.5% of peak load. Figure 5.10 and 5.11 are plots of the sigmas for the various timescales vs. MWs of installed wind on a semilog scale and a plot of normalized sigma (MW/min) vs. installed MWs of wind.

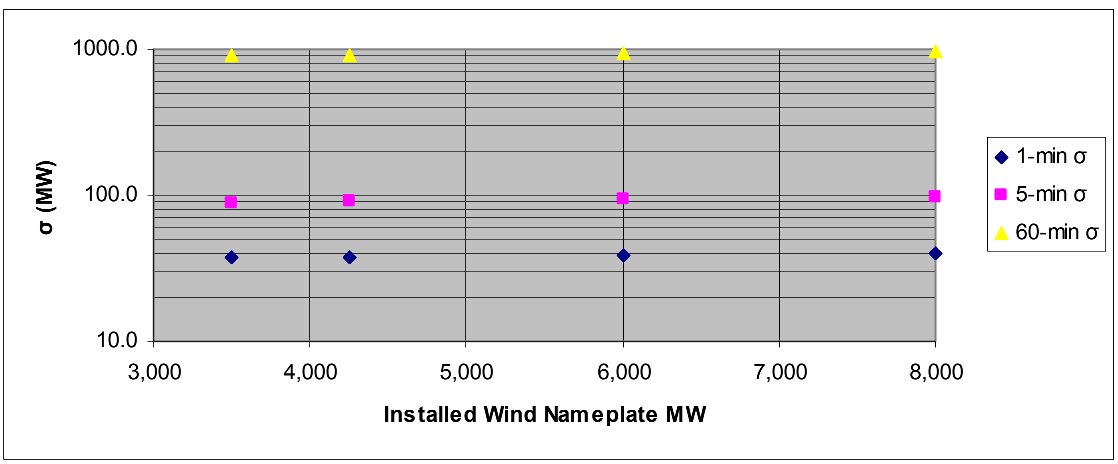


Figure 5.10: Net-load σ (adjusted for load growth) VS Installed Wind in MWs

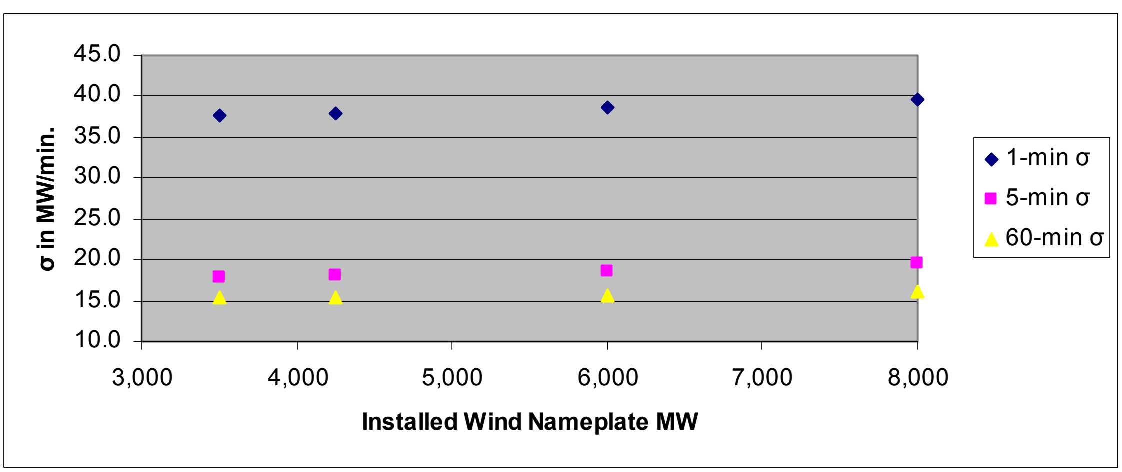


Figure 5.11: Normalized σ VS Installed Wind MWs

The plots confirm that the increase in annual sigma (σ) of the net load Δ with the load growth component removed increases linearly with a slight positive slope as the amount of installed wind increases. This result has been observed in other studies, although the slope observed in other studies has been steeper than observed in New York.

The magnitude of the σ for the net-load Δ changes by season, day of week, and hour of the day. Figure 5.12 below presents a plot of the monthly σ for the 10-min. Δ for 6,000 and 8,000 MWs of installed wind based on the 2018 peak load and 2006 weather data.

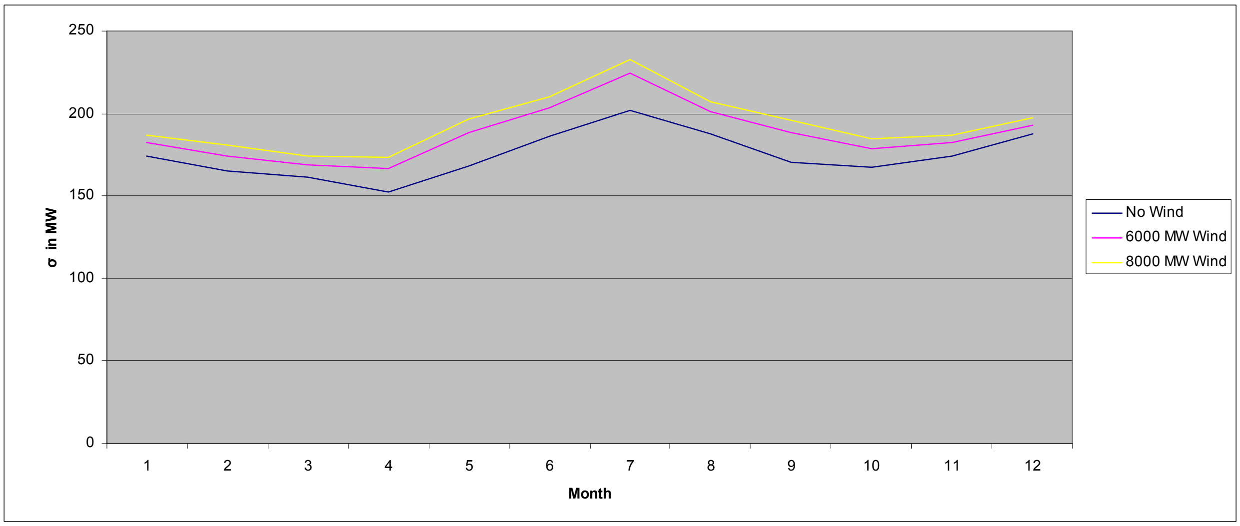


Figure 5.12: Monthly σ of the 10-min. net-load Δ for 2018 Based on 2006 Wind Data

Figure 5.13 shows that the net-load Δ is highest during months of highest loads and lowest during period of minimal loads. A plot of sigma by hour of the day shows that sigma will also vary by time of day and is generally highest during the morning ramp up and the evening ramp down. Figure 5.14 is a plot of the 5 minute sigma by month and hour of the day for hour beginning 0500, 1300, and 1900 for 2008 actual and 8,000 MW of simulated wind for 2018.

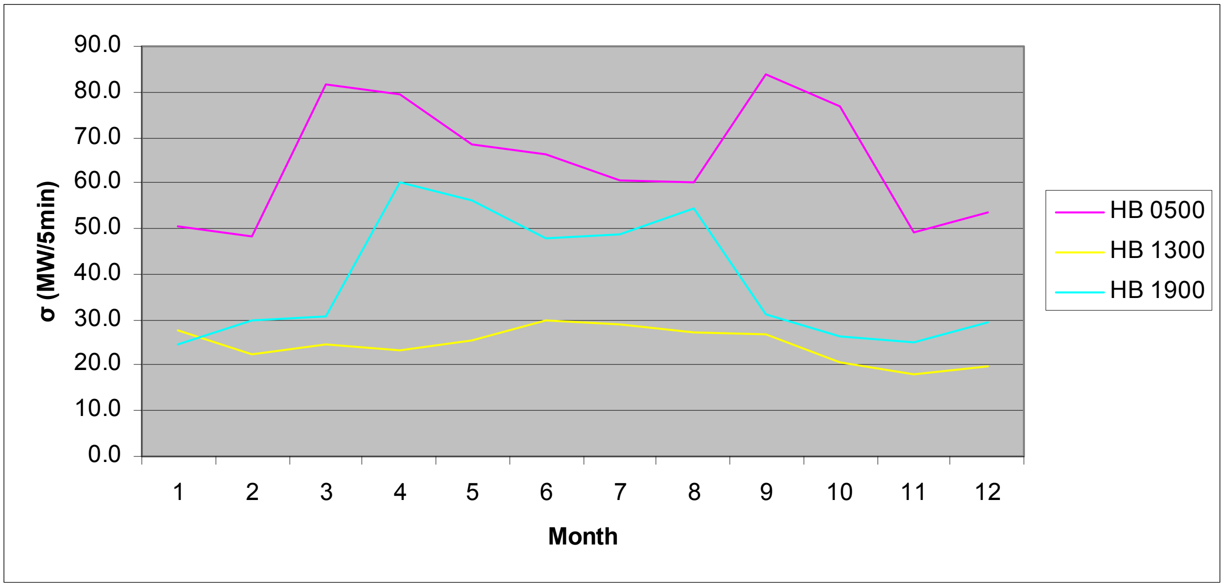


Figure 5.13: Sigma by the Hour of the Day for 5-min. Net-Load Δ for 2008

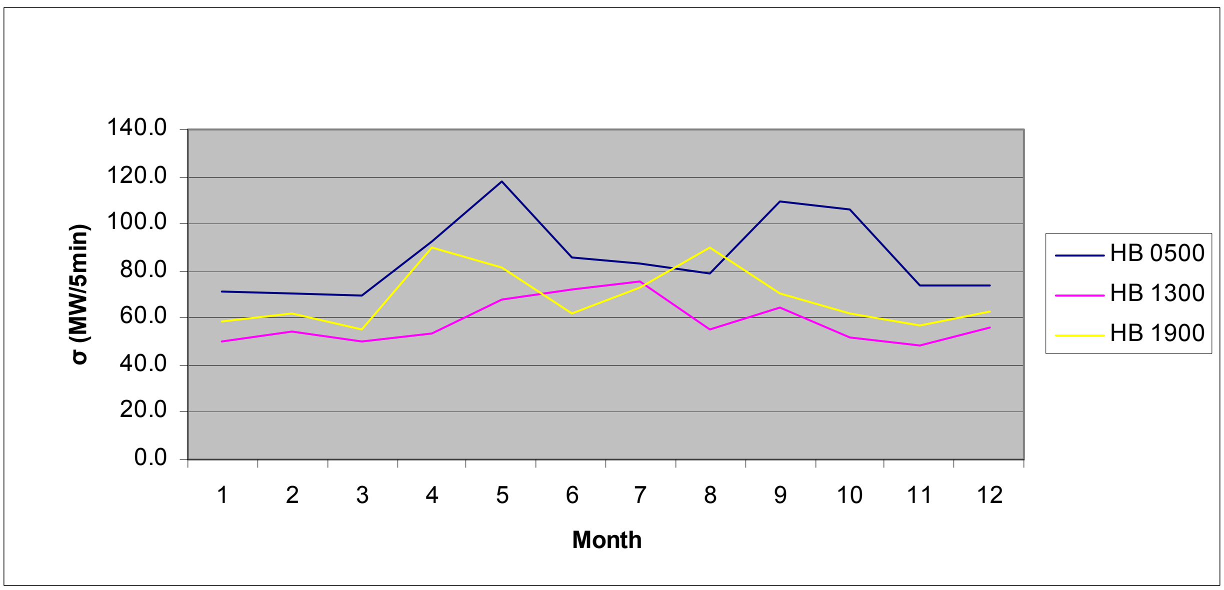


Figure 5.14: Sigma by the Hour of the Day for 5-min. Net-Load Δ for 2018

The above graphics have shown that net-load variability increases with increasing wind penetration. The net-load is important because the net-load is what the conventional generation will need to follow. This will result in the need for increased system flexibility. Flexibility can manifest itself in terms of a need for increased regulation requirements in the minute-to-minute timeframe, as well as increased frequency of larger magnitude ramps that occur in the five to ten minute, and hour or longer timeframes. The next three sections discuss the impact of the net load variability on the system regulation, hourly ramping events, and operating reserves.

5.4.6. Impact of Increasing Wind Penetration on System Regulation

Regulation requirements are established to address the variability of load and wind (net-load variability) that may occur within a 5-minute dispatch interval. This section of the report will outline the methodology used to establish regulation requirements at the specified wind penetration and forecasted load levels included in the study.

Regulation Study Approach

In order to evaluate the going-forward regulation requirements, the wind and load data as explained in prior sections of this report is leveraged. Actual 2005 and 2006 meteorological data (e.g., wind speed and direction) is used to simulate NYCA wind generation in 5-minute intervals at the specified wind penetration levels of 3,500MW, 4,250MW, 6,,000 MW, and 8,,000 MW as shown in the Table 5-5 below. In addition, actual 2005 and 2006 load shape data is used to project NYCA 5-minute load for the study years of 2011, 2013 and 2018. The 2005 data forms the basis of the regulation requirements analysis with 2006 data used for validation purposes.

Table 5-5: Projected Peak Loads and Wind Plant Penetration Levels

Year	Projected Peak Load (MW)	Projected Wind Penetration (MW)	
		Level 1	Level 2
2011	34,768	3,500	4,250
2013	35,475	4,250	6,000
2018	37,130	6,000	8,000

The coincident wind and load data is evaluated to determine the net-load on an interval-by-interval basis, as well as the deltas, or differences, between successive intervals. By looking at the net-load variability, situations in which load and wind move in the same direction (resulting in a lesser net change) and situations in which load and wind move in opposite directions (resulting in a greater net change) are considered.

In order to establish the data set of net-load differences between successive intervals, 5-minutes of load and 10-minutes of wind output deltas are considered as shown in the equation below.

Delta Net-Load = ΔLoad (t-(t-1)) - ΔWind (t-(t-2))

where t, t-1 and t-2 represent 5-minute intervals

As shown in the Diagram 5-1 below, this equation would for example, take the difference in the load between the 5-minute interval of 6:50 and 6:55 and couple that with the difference in the wind output between the 10-minute interval of 6:45 and 6:55. Given that the NYISO has a 5-minute dispatch and that the NYISO uses a load forecast to project the load in the binding interval of the dispatch, it is appropriate to evaluate the 5-minute load deltas. The NYISO uses a persistence assumption for wind for the next 5-minute binding dispatch interval (leveraging the wind forecast for the further out advisory intervals). Persistence is the most accurate assumption in the near term and it simply applies the current actual wind output to the projected output. As a result, the system is exposed to 10-minutes of wind variability through the dispatch process which is why the regulation analysis takes into account 10-minutes of wind variability.

	5-Minute Load Deltas	10-Minute Wind Deltas
t = 6:55		
t-1 = 6:50		
t-2 = 6:45		

Diagram 5-1

The standard deviation of the resulting net-load data set is then determined to measure the variability. For each hour of each month, the net-load delta variability corresponding to a 3 sigma level (to incorporate 99.7% of the sample set) is calculated. The resulting 3 sigma value represents the amount of regulation resources required to cover system variability.

Study Considerations

In order to confirm the validity of the variability data the results were reviewed against historical performance and Operations' knowledge of system patterns. A few adjustments were made to the raw data in order to make the integration with the markets and daily operations more practical and seamless.

Seasonal Definitions – The regulation requirements have historically been broken into four seasonal groupings: April - May, June - August, September – October, and November – March, as shown in the Table 5-6 below. A comparison of the historical seasonal breakdown with the study results showed similar net-load variability patterns and support retaining the same seasonal divisions.

Table 5-6: Regulation Requirements: Historical (Pre-Study) Sunday & Weekday Requirements

	April - May		June - August		Sept - Oct		Nov - March	
HB	Current Sunday Req.	Current Weekday Req.	Current Sunday Req.	Current Weekday Req.	Current Sunday Req.	Current Weekday Req.	Current Sunday Req.	Current Weekday Req.
0	150	150	175	175	160	180	160	190
1	150	150	175	175	160	180	160	190
2	150	150	175	175	160	180	160	190
3	150	150	175	175	160	180	160	190
4	150	150	175	175	160	180	160	190
5	150	175	175	200	160	250	160	250
6	150	275	175	275	160	275	160	275
7	150	275	175	275	160	275	160	275
8	150	275	175	275	160	275	160	275
9	160	200	160	250	180	260	180	250
10	175	175	175	240	210	250	210	250
11	150	150	175	210	160	210	160	210
12	150	150	175	175	160	180	160	180
13	150	150	175	175	160	180	160	180
14	150	150	175	175	160	180	160	180
15	150	175	175	175	160	190	160	190
16	175	200	230	250	230	250	230	275
17	200	200	250	250	250	250	250	275
18	200	200	250	250	250	250	250	275
19	200	200	250	250	250	250	250	250
20	200	200	250	250	250	250	250	250
21	200	200	250	250	250	250	250	250
22	175	175	225	225	225	240	225	240
23	150	150	175	175	175	190	175	190

Control Performance Requirements – Regulation is required to balance resources and demand, thereby maintaining a satisfactory Interconnection frequency. For certain hours, the raw data study results show that a reduction in the regulation requirement as compared to historical values is possible. For these hours a validation of the new value as compared to the historical (2008/2009) Control Performance was performed. If the historical performance fell below a threshold level of 94% for the hour (NERC CPS2 requires a monthly average Area Control Error of at least 90%), the historical regulation value is maintained.

Study Wind Data Basis Year – As explained previously in the report, actual load and wind data from the years of 2005 and 2006 form the basis of the study simulations to project the higher wind penetration values and load levels. In the analysis of the regulation requirements, the base year of 2005 serves as the primary data source because there is some additional volatility in the net-load as compared to the 2006 data. The 2006 net-load variability data was also considered to compare overall results and to adjust particular hours if they appear inconsistent within a day.

Day of Week Requirements – The study data does not support having a unique Sunday requirement; a conclusion supported by a historical control performance review. Therefore, the new requirements are based on common hourly values for all days of the week.

Hourly Increments – The regulation values are set to 25MW increments.

Hourly Ramp – The hour to hour ramping of the regulation requirements is limited to 50MW in order to minimize unnecessary real-time energy price volatility.

Regulation Study Results

The final regulation requirements determined in the study are presented along with the historical weekday values (labeled "current") for ease of comparison. Each table represents a single load level (for example study year 2011 with a 34,768MW peak load) displayed with two wind penetration levels (for example study year 2011 includes a wind level of 3500MW and 4250MW).

The study results show that with a 3500MW wind level and 2011 load (34,768MW peak) the regulation requirements increase by 5MW based on a weighted average. The maximum increase is 100MW (a change from a 175MW requirement up to 275MW) for the June-August season HB23. The highest requirement is 300MW in the November-March season HB17.

For the highest wind penetration level of 8,000 MW coupled with a 2018 load (37,130MW peak), the regulation requirements increase by 116MW based on a weighted average. The maximum increase is 225MW (a change from a 175MW requirement to 400MW) for the June-August season HB14. The highest requirement is 425MW in the June-August season HB20/HB21.

The results Tables 5-7 through 5-10 included show the hourly values for each study condition and the shading included helps identify increases and decreases in the requirement as well as modifications due to some of the study considerations previously described.

Key: Results Tables 5-7 through 5-10

(teal)	**Increase in Requirement**
(orange)	**Decrease in Requirement**
(shaded box)	**Requirement modified to eliminate > 50MW delta in consecutive hours**
Underlined Values	**Requirement modified due to historical CPS 2 performance**

Table 5-7: Legend

Table 5-8: Regulation Requirements: Study Year 2011 (34,768MW Peak Load)

2011	April - May			June - August			Sept - Oct			Nov - March		
HB	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW
0	150	175	175	175	225	225	180	175	200	190	200	200
1	150	175	175	175	175	200	180	175	175	190	175	200
2	150	175	175	175	175	175	180	150	175	190	175	175
3	150	175	200	175	175	200	180	175	200	190	150	175
4	150	225	225	175	225	225	180	225	250	190	175	175
5	175	225	225	200	250	275	250	275	300	250	225	225
6	275	225	225	275	275	275	275	275	275	275	275	275
7	275	200	225	275	275	275	275	250	275	275	275	275
8	275	200	200	275	275	275	275	225	225	275	275	275
9	200	175	175	250	225	225	260	200	225	250	225	225
10	175	200	200	240	225	225	250	175	200	250	175	200
11	150	200	225	210	250	275	210	200	200	210	175	200
12	150	175	175	175	225	250	180	200	225	180	175	200
13	150	175	175	175	225	250	180	200	225	180	175	175
14	150	175	175	175	250	275	180	175	200	180	175	175
15	175	175	200	175	225	225	190	175	200	190	225	225
16	200	175	200	250	250	250	250	200	225	275	275	275
17	200	200	225	250	250	250	250	250	275	275	300	300
18	200	225	225	250	250	250	250	275	300	275	250	250
19	200	250	275	250	250	250	250	250	275	250	250	250
20	200	200	225	250	250	250	250	250	250	250	200	225
21	200	200	225	250	250	275	250	250	250	250	225	225
22	175	200	200	225	275	275	240	200	200	240	200	200
23	150	200	200	175	275	275	190	225	250	190	200	200

Table 5-9: Regulation Requirements: Study Year 2013 (35,475MW Peak Load)

2013	April - May			June - August			Sept - Oct			Nov - March		
HB	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW
0	150	175	200	175	225	275	180	200	225	190	200	225
1	150	175	225	175	200	250	180	200	225	190	200	250
2	150	175	200	175	175	225	180	175	200	190	175	225
3	150	225	250	175	200	225	180	225	250	190	175	200
4	150	275	300	175	250	275	180	275	300	190	225	250
5	175	300	325	200	275	300	250	325	350	250	275	300
6	275	250	275	275	300	325	275	275	300	275	325	350
7	275	250	250	275	275	275	275	275	300	275	275	300
8	275	200	250	275	275	275	275	225	275	275	275	275
9	200	225	250	250	225	275	260	225	250	250	225	275
10	175	225	250	240	225	275	250	175	225	250	200	275
11	150	200	225	210	275	275	210	200	250	210	225	300
12	150	200	250	175	250	300	180	200	250	180	200	250
13	150	225	275	175	225	275	180	200	250	180	200	225
14	150	200	250	175	275	325	180	200	225	180	175	200
15	175	225	275	175	250	300	190	200	225	190	225	250
16	200	175	225	250	250	325	250	225	250	275	275	300
17	200	200	250	250	250	325	250	275	300	275	300	325
18	200	225	275	250	250	275	250	275	325	275	250	275
19	200	275	325	250	250	300	250	275	325	250	250	325
20	200	225	275	250	275	325	250	250	300	250	225	275
21	200	225	275	250	250	325	250	250	275	250	225	275
22	175	225	250	225	275	325	240	225	250	240	250	300
23	150	225	250	175	275	325	190	250	275	190	200	250

Table 5-10: Regulation Requirements: Study Year 2018 (37,130MW Peak Load)

2018	April - May			June - August			Sept - Oct			Nov - March		
HB	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW
0	150	225	250	175	250	300	180	225	275	190	250	275
1	150	225	275	175	250	325	180	250	300	190	250	300
2	150	225	275	175	225	275	180	225	250	190	225	300
3	150	275	300	175	250	275	180	275	300	190	225	250
4	150	325	350	175	300	325	180	325	350	190	250	275
5	175	325	350	200	300	325	250	375	400	250	300	325
6	275	275	300	275	350	375	275	325	350	275	350	375
7	275	300	300	275	300	375	275	325	375	275	300	375
8	275	275	300	275	275	325	275	300	350	275	275	350
9	200	250	275	250	275	325	260	250	300	250	275	325
10	175	275	300	240	250	300	250	225	275	250	250	300
11	150	225	275	210	275	325	210	275	300	210	300	300
12	150	250	325	175	275	375	180	250	300	180	250	300
13	150	275	350	175	275	350	180	250	300	180	225	275
14	150	225	300	175	325	400	180	225	275	180	225	275
15	175	250	325	175	300	350	190	250	300	190	250	325
16	200	225	275	250	325	400	250	275	300	275	300	350
17	200	250	300	250	325	400	250	325	350	275	350	400
18	200	275	325	250	275	350	250	300	325	275	300	350
19	200	325	375	250	300	375	250	325	375	250	325	400
20	200	275	325	250	350	425	250	300	375	250	300	375
21	200	275	325	250	350	425	250	300	375	250	275	325
22	175	250	275	225	350	400	240	250	325	240	275	350
23	150	250	300	175	300	350	190	275	325	190	250	325

Figures 5-15 through 5-17 display the historical values (labeled "current") requirements along with the requirements as determined in the study. As the load and wind penetration levels increase, the regulation requirement on average also increases.

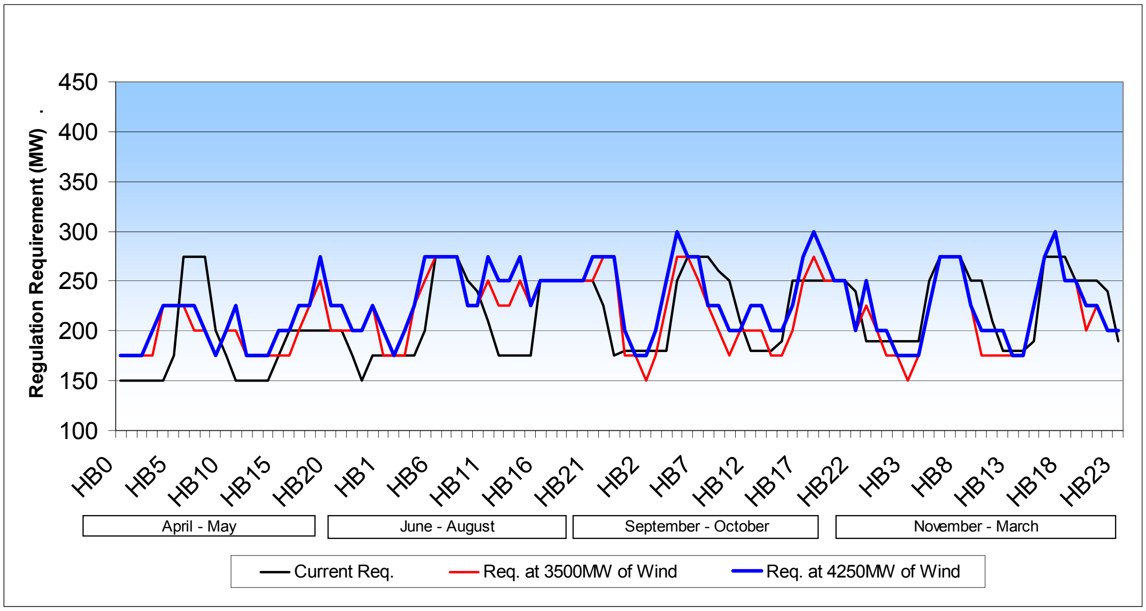


Figure 5.15: Current and Proposed Regulation Requirements

3500/4200 MW of Wind 2011 – 34,768 Peak Load

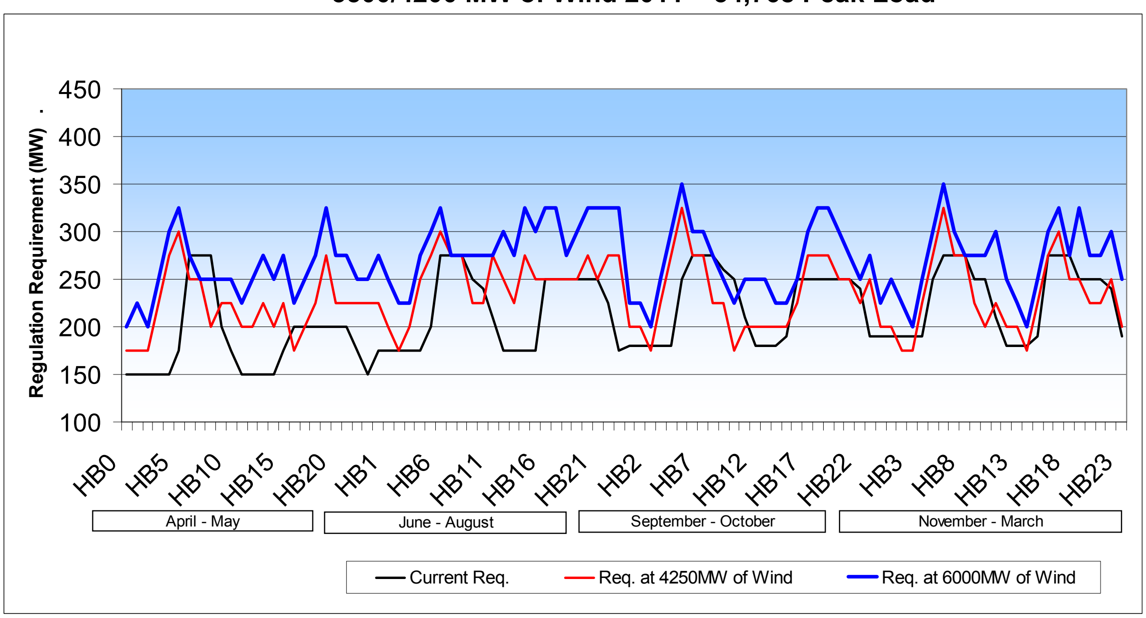


Figure 5.16: Current and Proposed Regulation Requirements

4250/6000 MW of Wind 2013 – 35,475 Peak Load

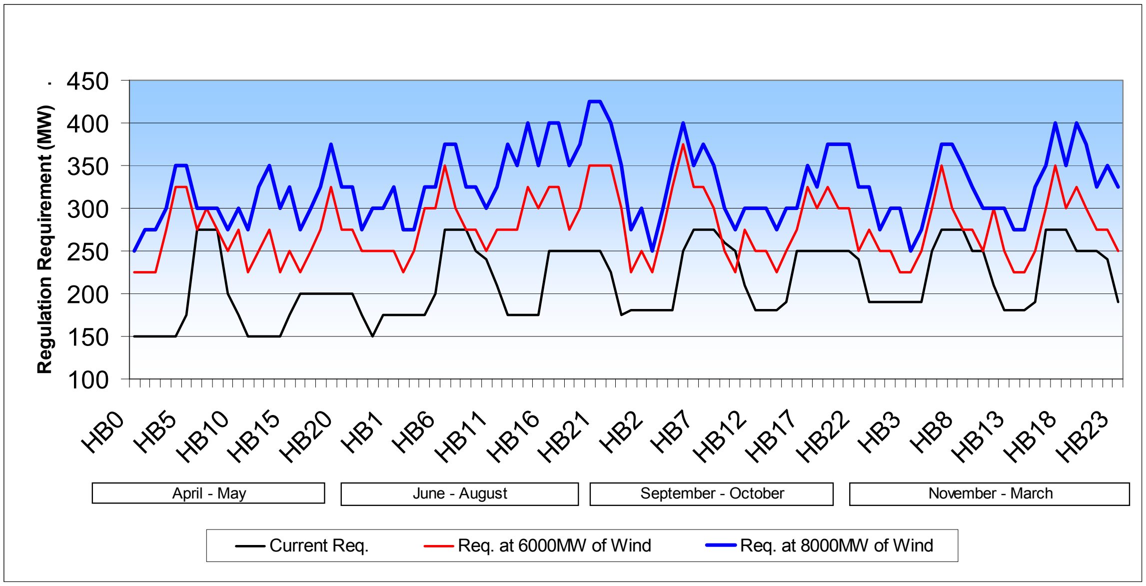


Figure 5.17: Current and Proposed Regulation Requirements

6000/8000 MW of Wind 2018 – 37,130 Peak Load

5.4.7. Impact of Increasing Wind Penetration on Load Following and Ramping

Introduction

To evaluate how increasing wind penetration would impact load following and ramping events, both the simulated net load data and simulated dispatch data from GridView were analyzed. In conducting the evaluations, the simulated data were analyzed to determine how the load and wind interact to impact the level of ramping that dispatchable generation needs to follow and how the magnitude of the load delta data compares to the net load delta for five minute, 1-hour, and 4-hour time frames. The five minute timeframe is indicative of the magnitude of the changes that will occur during the economic dispatch cycle, while one to four hours would be indicative of what would occur in the morning up and evening down ramps. Finally, simulated dispatch data generated by the GridView production cost model were analyzed to determine how the increased frequency of higher magnitude ramp changes would impact the dispatch of thermal plants.

Figure 5.18 presents a plot of the hourly loads, wind generation, and resulting net hourly ramps for the week of peak wind generation (week beginning the second Tuesday of February at 0000 hours) based on 2018 loads and 8,000 MW of installed wind generation. Figure 5.19 presents a plot of the hourly loads and net-load ramps for that week.

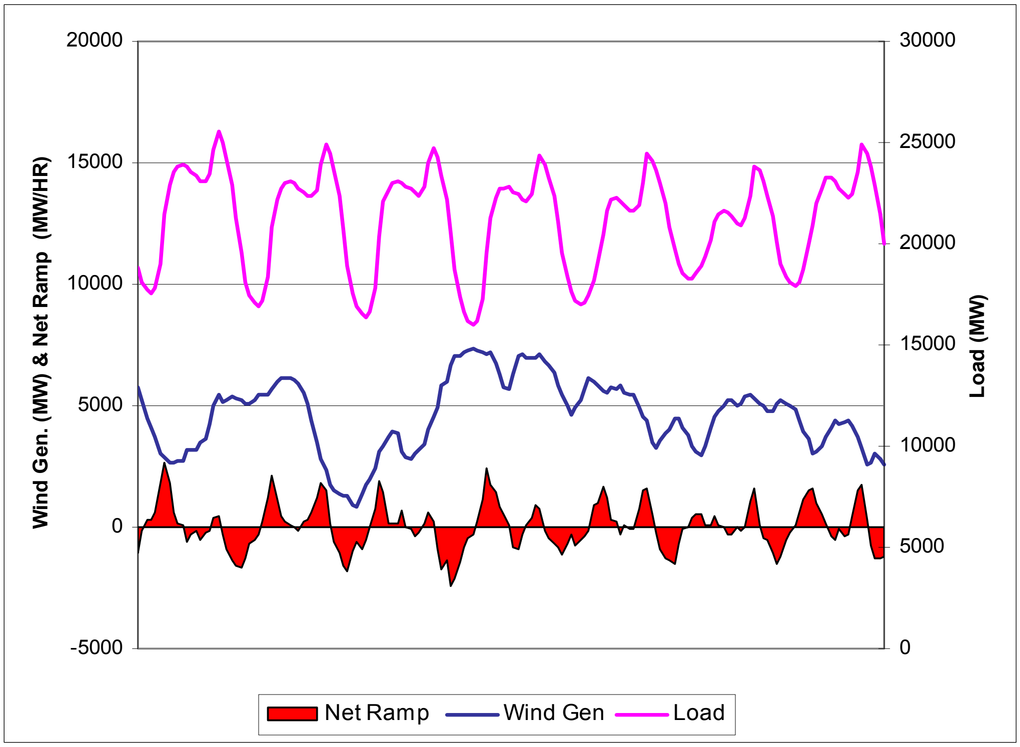


Figure 5.18: 2018 Hourly Loads, Wind Generation and Ramps for the Week of Peak Wind Generation

Figure 5.19 presents the hourly ramp resulting from the load and the net-load ramp for the same week.

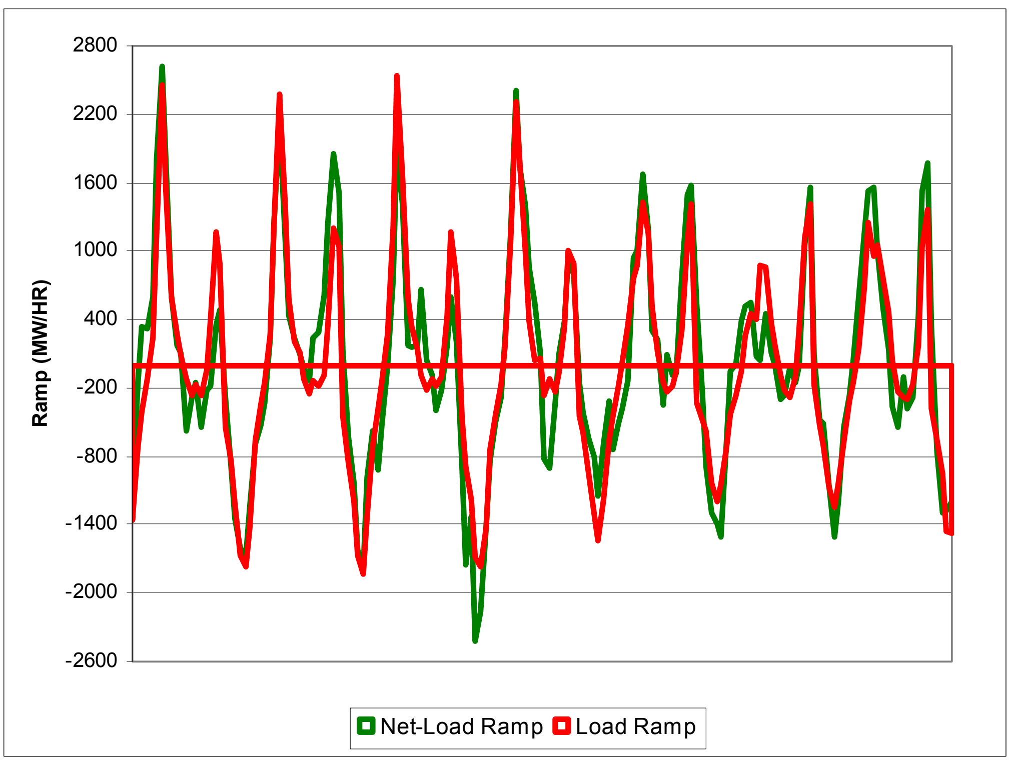


Figure 5.19: 2018 Hourly Net-Load Ramps VS Load Ramps for the Week of Peak Wind Generation

Figures 5.20 and 5.21 present the same results for the peak load week for 2018.

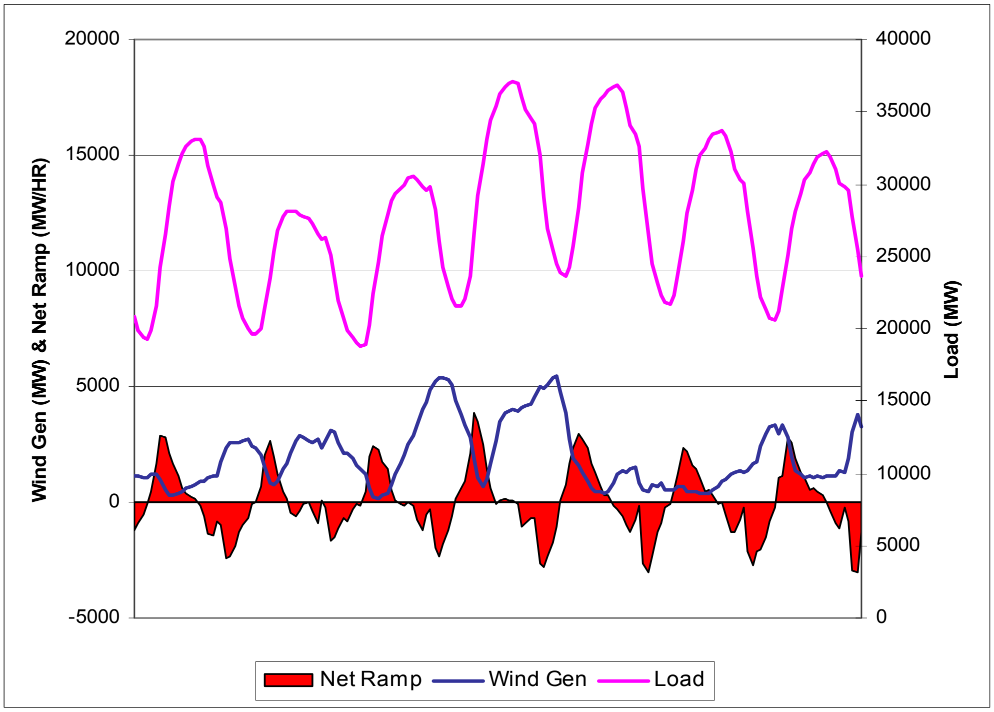


Figure 5.20: 2018 Hourly Loads, Wind Generation and Ramps for the Week of the Peak Load

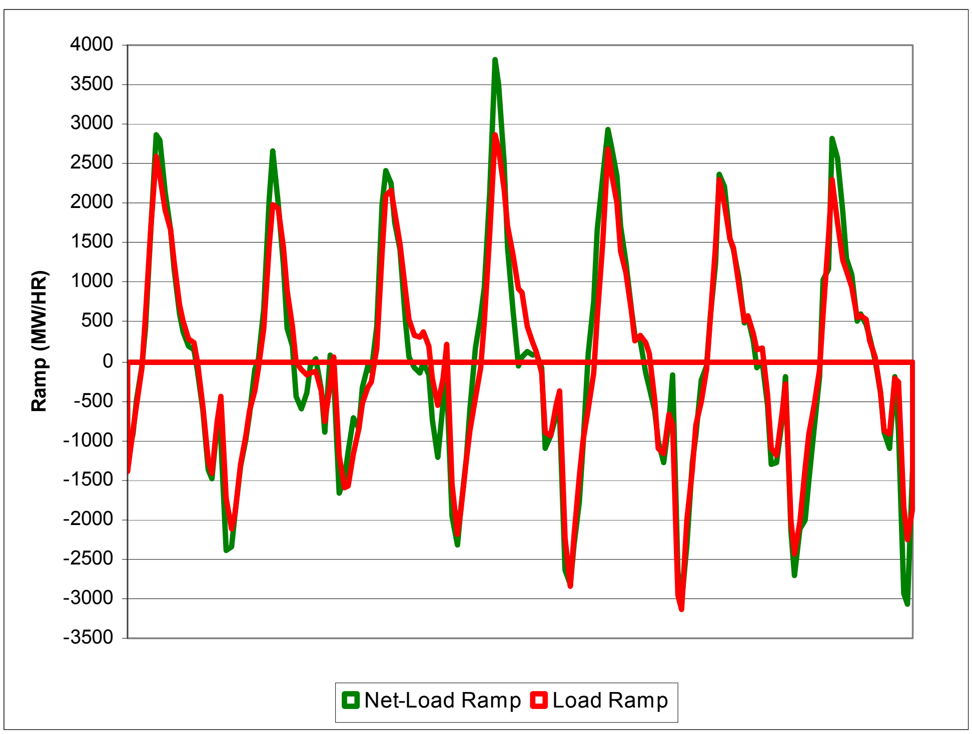


Figure 5.21: 2018 Hourly Net-Load Ramps VS Load Ramps for the Week of the Peak Load

These graphics demonstrate how the variable nature of wind generation can increase the ramps that the dispatchable generation needs to respond to. When the net-load (green or dashed line) exceeds the load ramp (red line) the wind is increasing the hourly ramp. Likewise, when the net-load is less than the load ramp wind is reducing the ramp that the dispatchable generation needs to follow. Overall, the variable nature of generation tends to increase the range and maximum magnitude of the ramps to which dispatchable generation needs to respond.

Range and Magnitude of Net-Load Events

Figures 5.22 through 5.28 present annual duration curves from highest to lowest for up and down ramps for 5 minutes (every 12th point plotted), 1-hour, and 4-hour ramps/load following events. These graphics present the full range of up and down ramping events as simulated for a full year. The 5-minute data is indicative of what the range and magnitude of ramping events for the economic dispatch cycle would be, while the 1-hour and 4-hour ramp durations are indicative of what would be encountered in the morning ramp up and the evening ramp down. This data is presented based on 8 GW of installed wind. Figure 5.22 presents the 5-minute up and down ramps for 8760 hours. Figures 5.23 and Figures 5.24 present the 50 highest hours for 5-minute up and down ramps for greater fidelity of maximum ramp events. The Figures 5.25 through 5.27 presents the same data for one hour ramp events. Figure 5.28 presents the annual duration curve for four-hour ramping events.

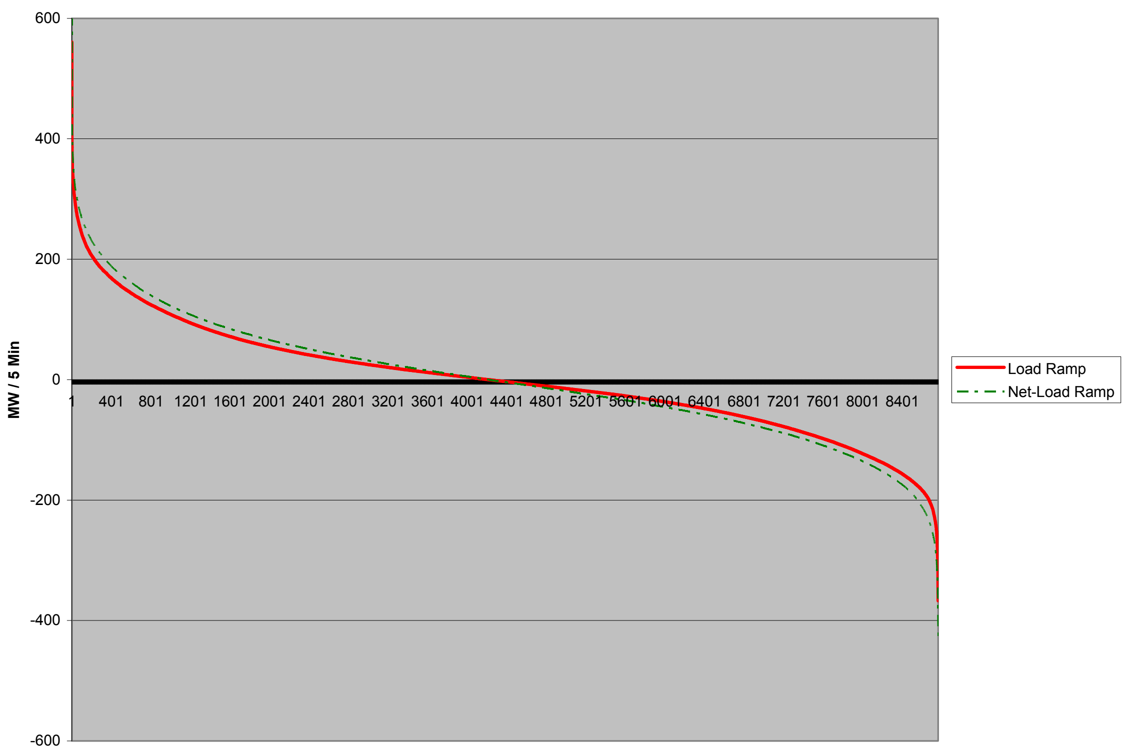


Figure 5.22: Annual Duration Curve for 5-Minute Ramp Events

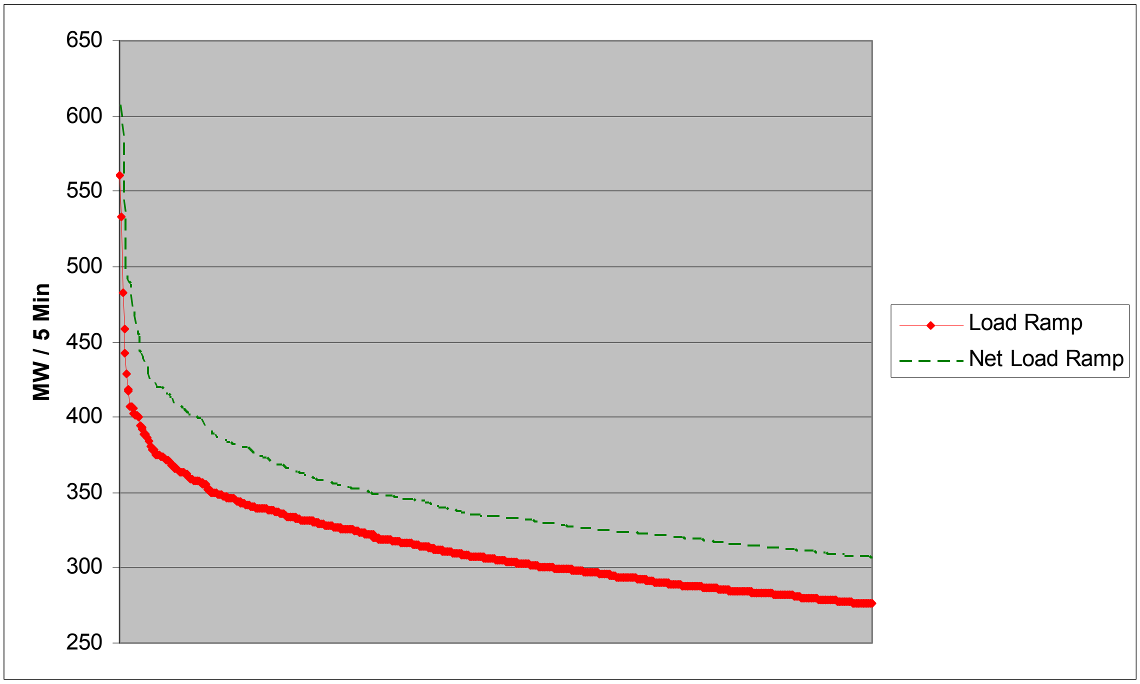


Figure 5.23: Top 50 Hours of 5-Minute Up Ramp Events

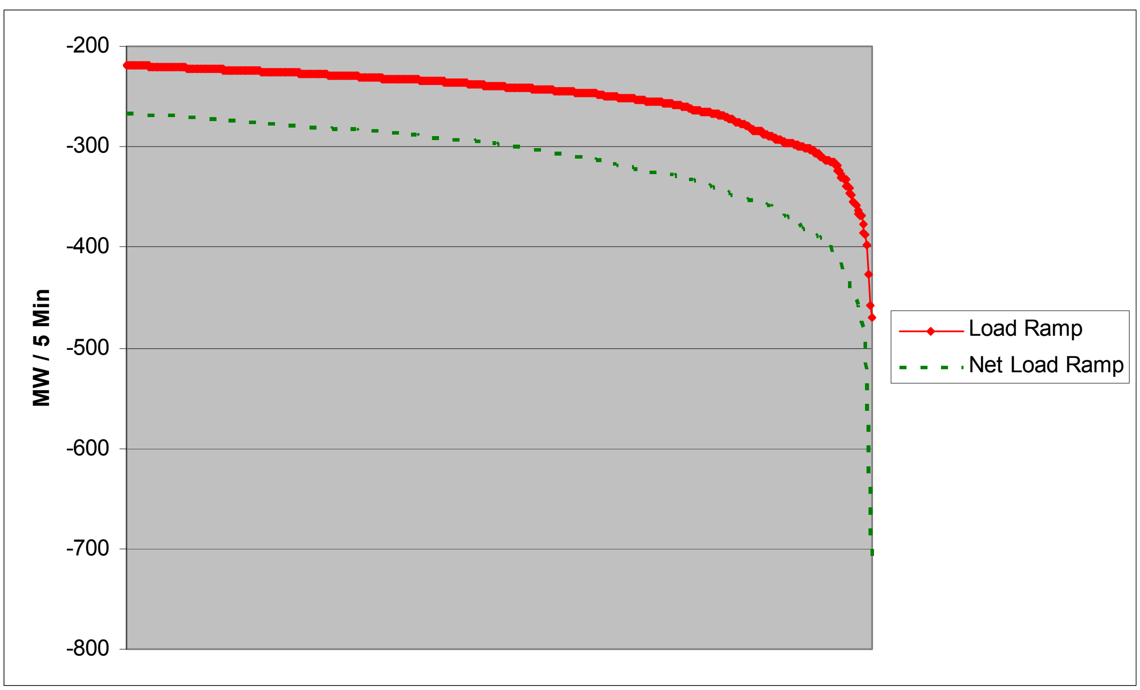


Figure 5.24: Top 50 Hours of 5-minute Down Ramp Events

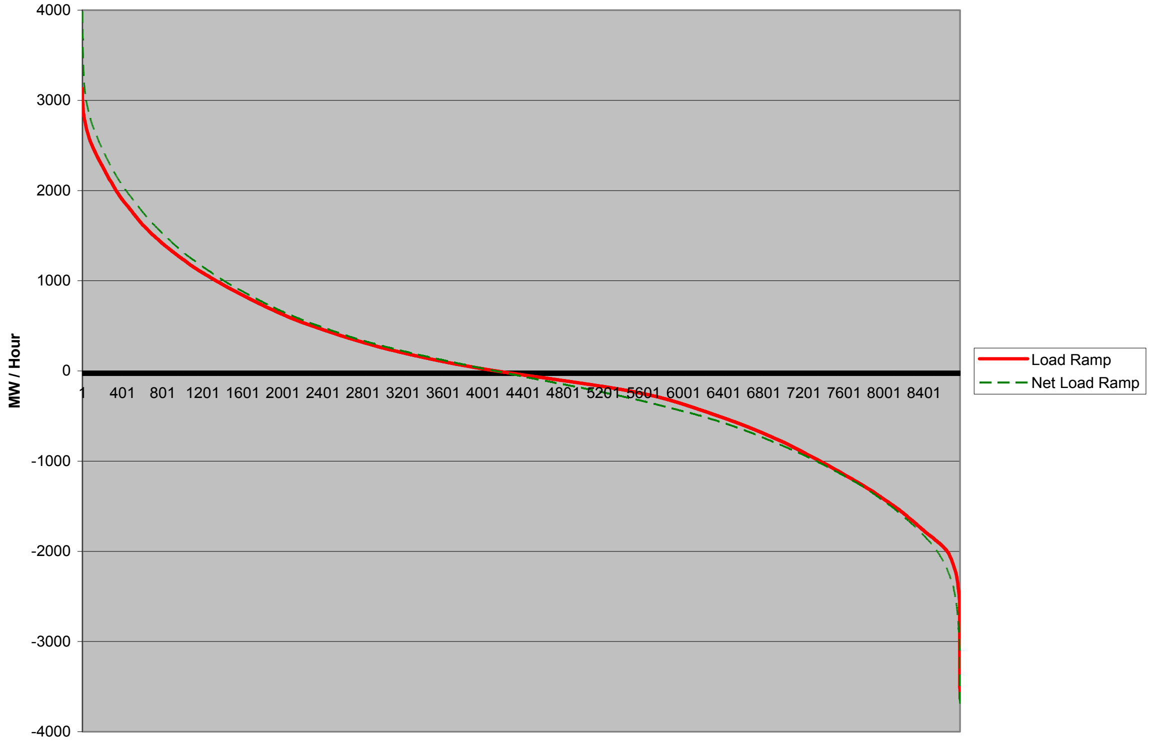


Figure 5.25: Annual Duration Curve for 1-Hour Ramp Events

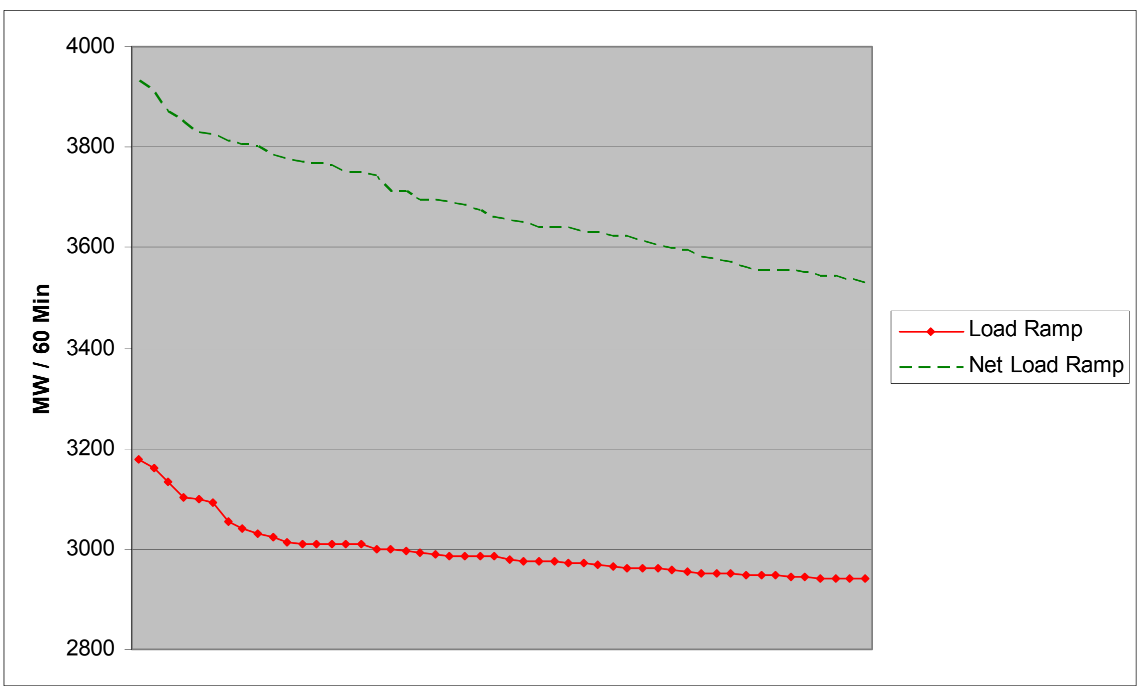


Figure 5.26: Top 50 Hours of 1-Hour Up Ramp Events

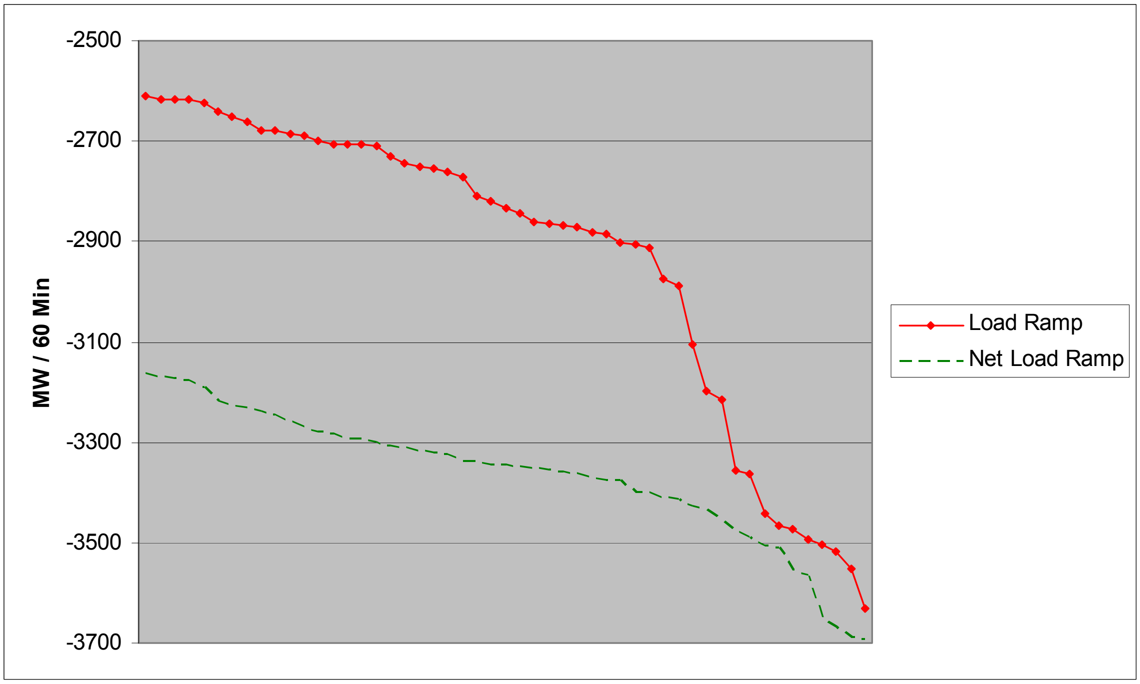


Figure 5.27: Top 50 Hours of 1-Hour Down Ramp Events

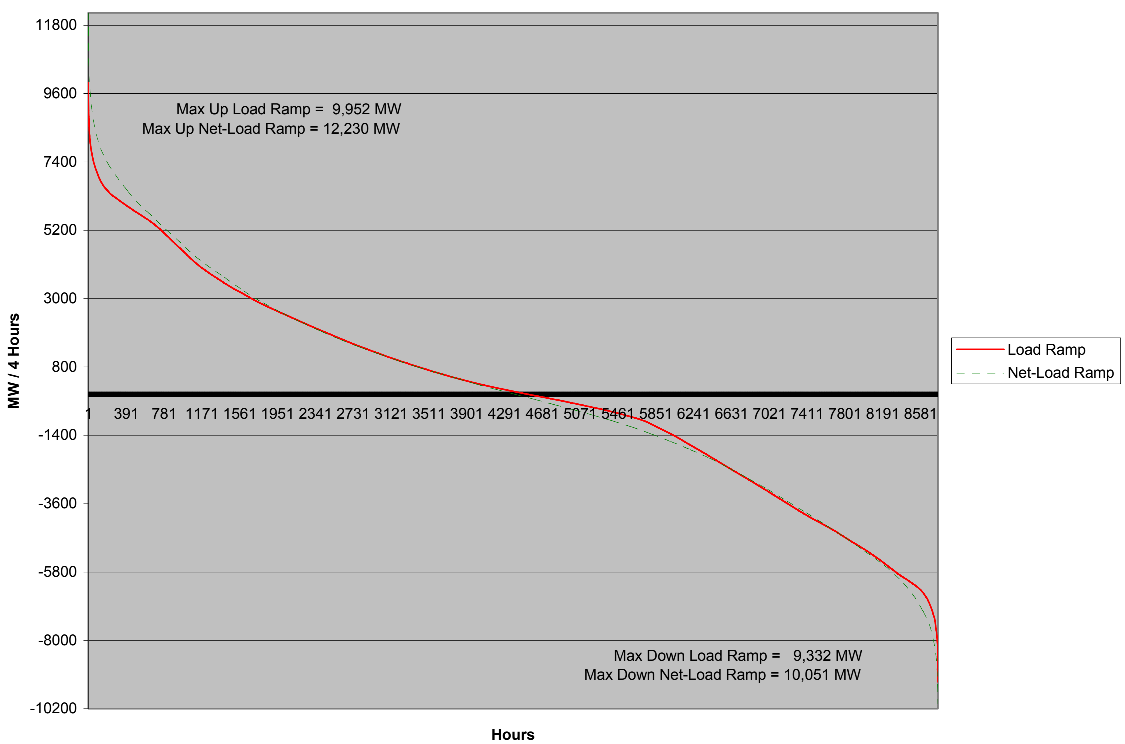


Figure 5.28: Annual Duration Curve for 4-Hour Ramp Events

These graphics, which are based on 2018 loads or a peak load of 35,000 MW and installed wind of 8 GW, demonstrate that the variable nature of wind generation will result in an increase in the magnitude of ramp/load following supplied by dispatchable generation. Based on the simulations, the average 5-minute net-load up ramp will be 81.6 MW compared to an average 5-minute load ramp up of 70.8 MW. The average down 5-minute net-load ramp down of 76.2 MW compared to an average 5-minute load down ramp of 66.0 MW. The maximum 5-minute load ramp up of 560.5 MW increases to 607 MW for the net-load ramp, while the ramp down increases from 469.0 MW to 720.0 MW.

The average 1-hour load ramp up increases from 803 MW to 864 MW for the net-load ramp, while the 1-hour average down load ramp will increase from 714 MW to 769 MW. The maximum 1-hour load ramp up increases from 3,178 MW to 3,929 MW for the net load ramp, while the maximum 1-hour ramp down increases from 3,632 MW to 3,692 MW. The average 4-hour load ramp up increases from 2,752 to 2,895 MW for the net load ramp, while the maximum increases from 9,952 MW to 12,230 MW. The average 4-hour load ramp down increases from 2,649 MW to 2,789 MW for the net load, while the maximum increases from 9,334 MW to 10,052 MW. The overall conclusion is that the dispatchable resources will experience higher magnitude ramping events and be subject to a much wider range of events.

Impact of Net Load Ramping on System Dispatch

NYISO's day-ahead scheduling process and security constrained economic dispatch are the primary tools for scheduling sufficient resources to supply the load as well as respond to system changes such as ramping events. The GridView production costing tool simulates the commitment and dispatch process. Data simulated by GridView were analyzed to determine how the integration of wind generation into the resource mix and the resulting increase in net-load ramping events impact dispatch. The addition of 8 GW of nameplate wind generation to the resource base will displace approximately 22,000 GWh of energy previously generated by dispatchable gas and oil fired generation. The focus of the evaluation was the impact of the wind resources on the system's thermal fossil generation which is usually the higher cost resources and is dispatched after hydro and nuclear. In addition to hydro resources, thermal fossil-fuel-fired plants are generally the primary resources that are used for ramping and load following.

The first step is to review the simulated data to determine how the total MW of thermal fossil fired generation changes with increasing installed wind generation. Figure 5.29 is a plot of an hourly duration curve, which displays the MW of thermal generation committed in the GridView simulations by hours from the highest level of hourly commitment to the lowest level of commitment. This graphic presents results for 2013 load levels and the base case of 1,275 MW of installed wind up to 6,000 MW of installed wind. Figure 5.30 presents the results for 2018 loads and the base case of 1,275 MW of installed wind and 8,000 MW of installed wind.

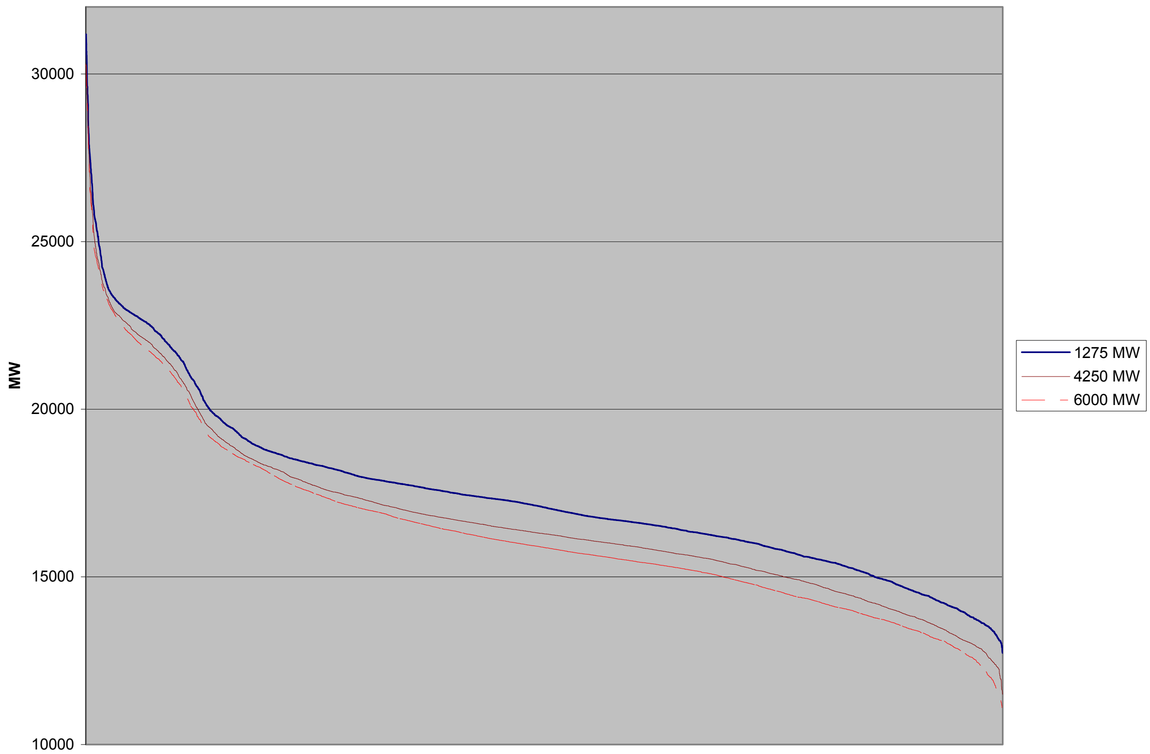


Figure 5.29: Commitment of Thermal Fossil Generation VS Installed Wind 2013 Loads

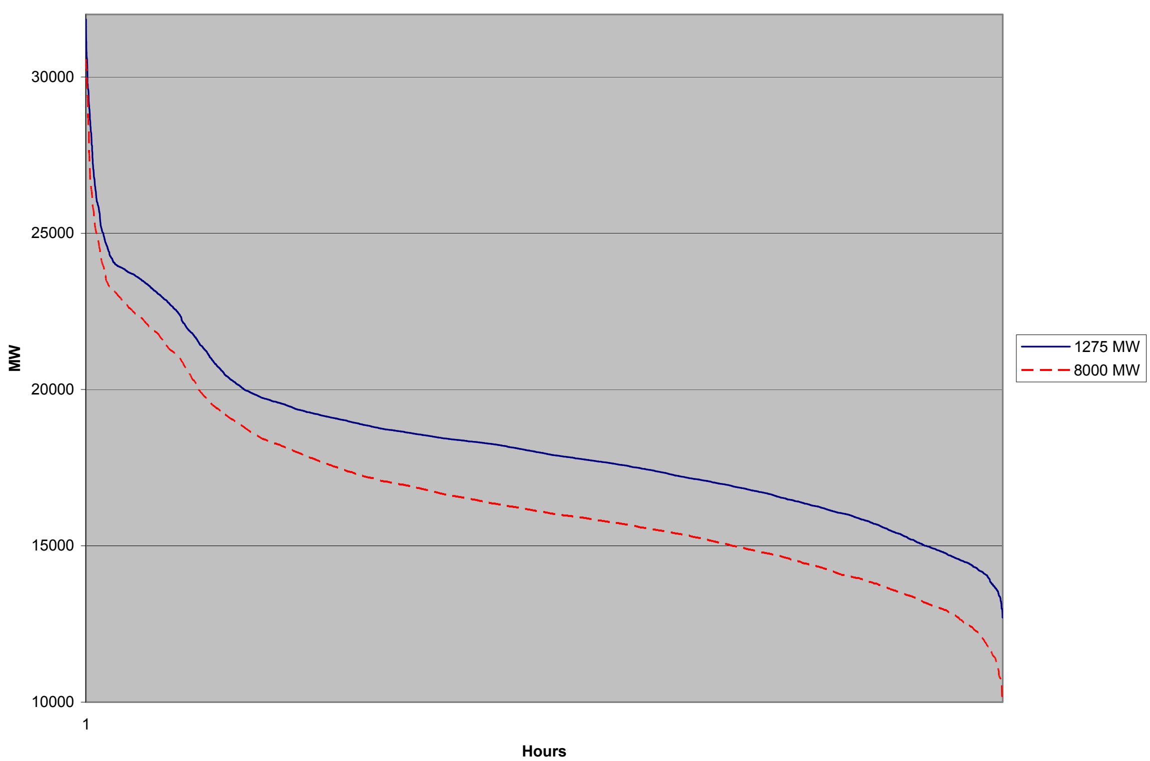


Figure 5.30: Commitment of Thermal Fossil Generation VS Installed Wind 2018 Loads

As expected, the addition of wind generation reduces the amount of thermal fossil fired generation that is committed to supply energy and provide load following. The simulations for the 2018 loads in the base case resulted in an average commitment of thermal fossil units of 18,287 MW for the base case or 1,275 MW of nameplate wind. The 8 GW wind scenario resulted in an average thermal fossil generating plant commitment of 16,574 MW, or a reduction of 1,713 MW, when compared to the base case. The maximum commitment was reduced from 31,842 MW to 30,571 MW while the minimum commitment was reduced from 12,707 MW to 10,094 MW. The addition of approximately 6,725 MW of nameplate wind in resulted in an average reduction in the amount of thermal fossil fired generation dispatched to meet load of approximately 25% of installed nameplate wind for the 2018 scenario. For the maximum commitment, the reduction was 1,271 MW or 18.9% of nameplate.

Although these numbers provide insight into how wind generation affects the overall level of MW of thermal fossil fired generation that are committed to supply energy and follow load, the analysis does not provide any explicit insight into whether the commitment of thermal fossil-fired plants is higher than it would otherwise be because of the variable nature of wind plant output and the need to follow it (i.e., net-load). To investigate this issue further, an analysis of the committed fossil fired generation relative to the amount energy it supplied. This was done by taking the level of committed MW of fossil fired generation for each hour and determining how much energy was produced by the committed fossil fired generation for that hour. A ratio of the committed MW divided by the MWh produced was created for each level of installed wind. This ratio was then plotted from highest to lowest ratio in the form of an hourly annual duration curve. Figure 5.31 presents the results for 2013 load levels and installed wind ranging from 1,275 MW to 6,000 MW. Figure 5.32 presents the results for 2018 loads and installed wind for 1,275 MW and 8,000 MW.

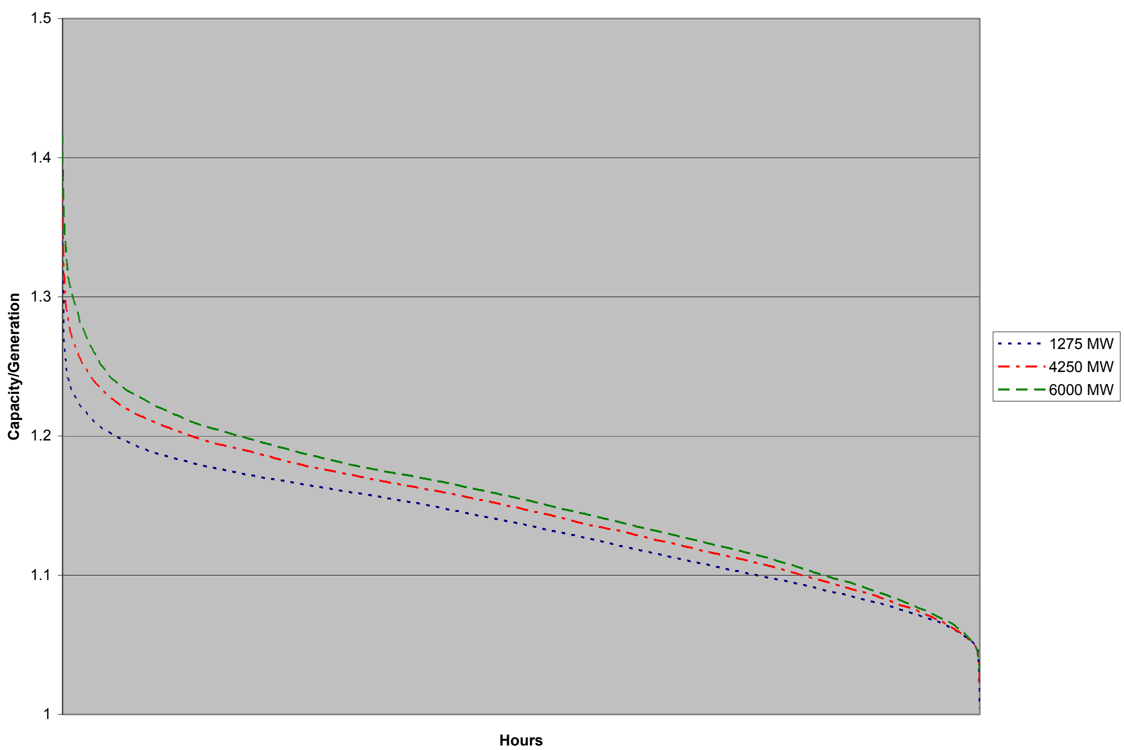


Figure 5.31: Ratio of the Committed Fossil Fired Generation MW to the Energy Produced

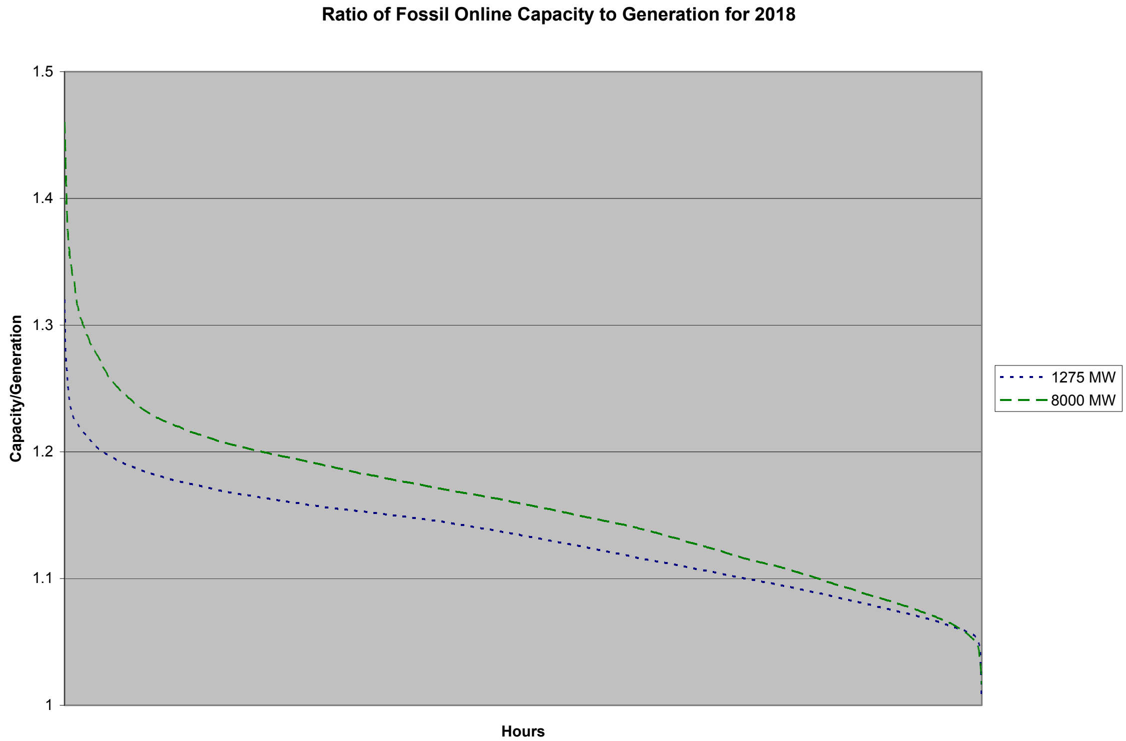


Figure 5.32: Ratio of the Committed Fossil Fired Generation MW to the Energy Produced

The graphics show that as you integrate more wind into the system resource mix, the ratio increases. This results because the fossil-fuel generation that has been committed is supplying less energy as wind penetration increases. It also implies that a larger percentage of the fossil fuel generation that is committed is being committed to be available when needed to provide ramping and to follow the net-load.

The final analysis that was conducted was to calculate the MW of ramping capability that was available on an hourly basis from thermal fossil-fired generation and compare it to the hourly net-load ramp requirement. This analysis was done for 2018 loads and 8 GW of wind. The hourly up and down ramping capability was calculated by determining how much capability existed between a generator's operating point and its minimum generation level or its maximum generation level depending upon what was needed in that hour.

Figure 5.33 presents a plot of the hourly net-load ramp both up and down against the ramp capability available up and down.

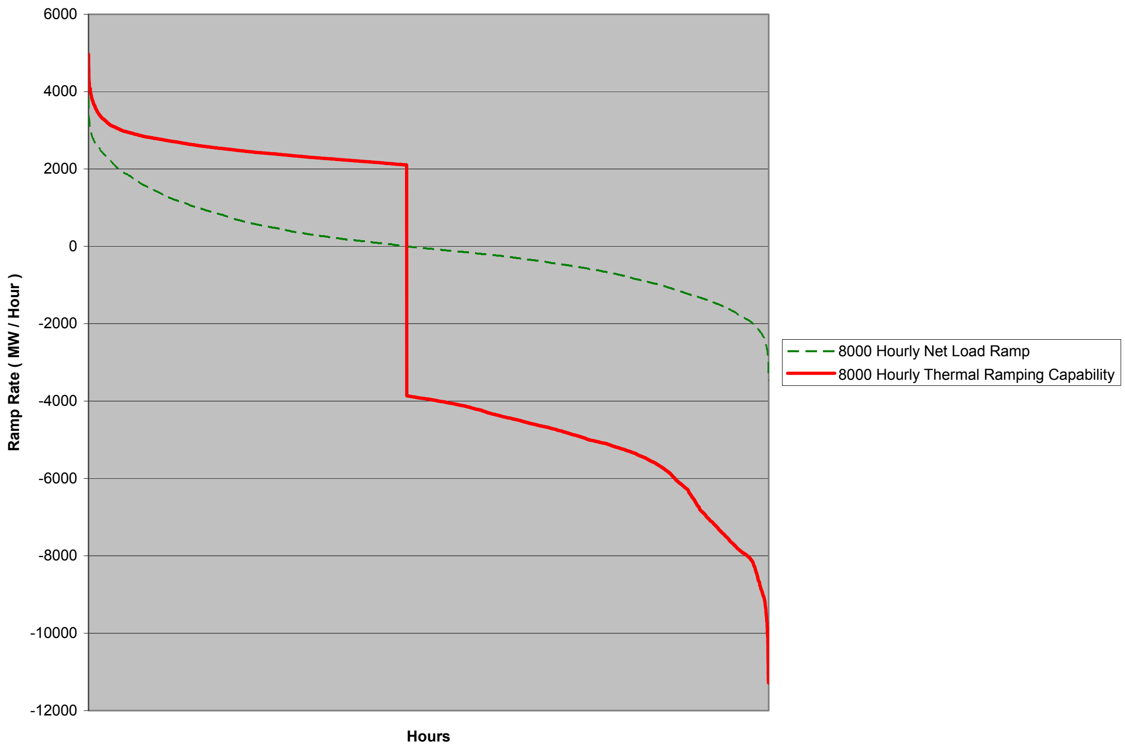


Figure 5.33: Fossil Fuel Ramping Capability VS Net-Load Ramp

Figure 5.33 show that there is more than sufficient ramping capability available from the fossil fueled generating units that have been committed to cover the hourly ramps. Also, the hourly down-ramp capability is far in excess of the down ramps that are observed. This is because of the need to back generation down at night to balance the load and generation during low night load conditions and yet have the generation available for the next day. A simulation was conducted where the wind was assumed to be zero for commitment purposes but did show up in real time. This extreme sensitivity did result in an over committed system and the need to curtail wind generation to satisfy minimum load constraints. Because the NYISO's on-line processes do include wind in the commitment process it is expected that curtailment of wind generation because of minimum generation issues will be avoided.

The above analysis leads to the following conclusions regarding the increase in the magnitude of net-load ramping event:

1. The NYISO dispatch processes are sufficient to reliably respond to the increase in the magnitude of the net-load ramps that result from the integration of the MW of installed wind studied.

2. The integration of wind will result in the need to commit less fossil fueled generation for dispatch operations but the variable nature of wind generation will result in a greater percentage of the fossil fuel generation that is committed being committed to cover the increased magnitude of net-load ramping events (i.e., follow the wind).

5.4.8. Impact of Increasing Wind Penetration on Operating Reserves

Operating reserves[8] are designed to cover the largest instantaneous loss of source or contingency event. The size of the current largest loss of source contingency is 1,200 MW. Reliability standards require the NYISO operations to be able to replace the instantaneous loss of 1,200 MW of energy generation within its balancing area with ten minutes. The analysis of the simulated data found for 8 GW of installed wind found a maximum drop in wind output of 629 MW in ten minutes, 962 MW in thirty minutes and 1,395 MW in an hour. The system is designed to sustain the loss of 1,200 MW instantaneously and replace it within ten minutes. Large loss of wind generation occurs over several minutes to hours. The conclusion is that wind generation will not result in any change in the amount of operating reserves the NYISO would need to have available for operations.

5.4.9. Impact of Increasing Wind Penetration on Resource Adequacy Requirements

Power Systems maintain system resources over and above that which are needed to meet the expected peak load. The amount of resources available above the peak load is generally referred to as the system reserve margin[9]. They are generally expressed as a percentage of the peak load. For instance, the NYISO's current installed reserve margin which is set by the New York State Reliability Council (NYSRC) annually is 18%. This means that the NYCA must have installed resources of 118% of the peak load to meet the NYSRC reliability rule.

These reserves are primarily designed to be available when resources are unavailable because of equipment failures or maintenance requirements. They also can be designed to serve as a hedge against unexpected increases in load (i.e., load uncertainty) or transmission outages.

Because wind resources are dependent on wind, they tend to have much lower availability factors than dispatchable resources and their unavailability can be highly correlated over a large area as shown in Figure 5-3 on page 15. The addition of resources with lower unavailability to the overall resource mix will generally result in a higher installed reserve margins to meet the reliability standard. This is because when resources have low availability or high unavailability, the probability of needing to call on other resources increases resulting in an overall increase in the level of reserves needed. Conventional resources generally have overall availabilities of 85 to 90% while variable generation such as wind generally has overall availabilities of around 30%.

The Table 5-11 below presents availability expressed as the capacity factor of the wind plants used in this study, developed from the AWS Truepower simulated wind plant output. Capacity factor is a measure of the actual energy produced by a generator as a percentage of its full potential for every hour of the year. A wind plant with a 30% capacity factor produces energy that totals only 30% of the equipment's potential based on its nameplate rating (nameplate times 8760 hours). This means that the majority of the time, the wind plant is producing well below its rated potential or full nameplate. One minus the capacity factor is a measure of the expected

[8] Operating reserves is the amount of resources that are needed to be available for real-time operations to cover the instantaneous and unexpected loss of resources. The New York power system is operated to protect the system against the sudden loss of 1,200 MW of resources. Operating reserve as stated is an operational concept while the reserve margin discussed in section 5.4.9 is a planning concept. The required reserve margin is designed to maintain, at an acceptable level, the risk of not having sufficient resources to avoid an involuntary loss-of-load event.

[9] Reserve margin is the amount of additional capacity above the peak load that is needed so that the risk of not having sufficient capacity available to meet the load meets the minimum reliability criteria. It is expressed as a percentage and is calculated by dividing the required level of resources by the expected peak load. Resource can be unavailable because of equipment failure, maintenance outage, lack of fuel, etc. The higher the unavailability of the overall resource mix the higher the installed reserve margin will be.

unavailability of the wind plant. Data is presented for the years 2005 and 2006 because wind varies not only over the short term but from year to year as well. Of the three years of wind data AWS, the year 2005 had the lowest wind availability and 2006 had the highest. Also, data for alternative tower heights is presented. In the NYCA, the latest generation of wind plants has 80 meter tower heights while future plants are expected to move to 100 meter tower heights because of the higher capacity factors they can provide. For the study, the first 1,500 MW of installed wind was simulated with 80 meter towers while the balance was with 100 meter towers.

Table 5-11: Expected Capacity Factors for Wind Plants

Year	Capacity Factor for Wind Plants with 80 Meter Tower Heights	Capacity Factor for Wind Plants with 100 Meter Tower Heights	Wind Offshore with 100 Meter Tower Heights
2005	26.4%	30.9%	37.9%
2006	29.7%	34.0%	40.4%

To gauge how wind plants would impact the installed reserve margin as the overall percentage of the resource base that are wind generators increases, the most recent NYSRC reserve margin study (see report entitled: “New York Control Area Installed Capacity Requirements for the Period May 2010 through April 2011”)[10] base case result was utilized as the starting point. The base case resulted in an installed reserve margin of 17.9% when the system calibrated to the “1 day in ten year” criteria or a loss-of-load-expectation (LOLE) of 0.1 days per year. It included wind resources of 1,326 MW. The wind resources were increased to a nominal 8,000 MW. The system now had more resources than required by criteria and the LOLE dropped to 0.017 days per year.

The wind load shapes were updated to reflect the higher capacity factor of 100 meter towers based on 2006 data. Also, the NYISO’s interconnection process now requires new generators to demonstrate that their capacity is deliverable to qualify for capacity payment. This is designated as Capacity Resource Interconnection Service (CRIS). Because sufficient transfer capability does not exist from upstate to downstate in order for the wind resources to qualify as capacity, transmission capacity would need to be added. The level of transfer capability necessary under the current rules was determined to be 457 MW. In addition to the updated load shapes, the NYSRC study base case transmission topology was adjusted to reflect an increase of 457 MW across the appropriate interface. The updated case was calibrated to the reliability criteria of the 0.1 days per year using the methodology of removing capacity. This resulted in a required installed reserve margin of 29.9% with 8 GW of installed wind.

The LOLE analysis also provides insight into the effective load carrying capability (ELCC) of wind generators. ELCC is a methodology to gauge the LOLE benefits that accrue from the additional generating capability relative to its nameplate. A conventional generating resource with a nominal 5% forced outage rate and downtime for maintenance can support a load equivalent of approximately 85 to 90% of its nameplate rating. That is, it has a UCAP value or has an equivalent load carrying capability of 85 to 90% of nameplate. The addition of the incremental wind resources to the NYSRC base case reduced the LOLE to approximately .02 using the existing load shape from the 2004 study. To return the system to the minimum criteria of 0.1 days per year require the removal of 1,440 MW of perfect generation. The result is that by adding 6,654 MW of additional wind (the NYSRC base case modeled 1,346 MW of installed wind) the system was able to support an additional 1,440 MW of load carrying capability or 21.6% of nameplate. This compares to 10% for the 2004 study.

[10] http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

The additions of transfer capability to the UPNY-SENY interface, as well as the update of the wind shapes based on 2006 wind data with more coincident wind profile and to reflect the impact that more of the wind plants will be built with 100 meter towers, resulted in the ELCC[11] of the system increasing by a total of 2,500 MW. However, the addition of the increased transfer capability increases the benefits of all resources above that interface including emergency assistance which means the total increase can not be attributed to the addition of the wind resources alone.

The overall conclusion from the above, all else being equal, is that wind resources need to be supported by a larger installed base of resources because of their higher overall unavailability when compared to other resources in conjunction with their variable and less predictable nature. However, it should be noted that the NYISO's capacity market requires load serving entities to procure unforced capacity (UCAP) and capacity is derated to its UCAP value for purchase. As a result the total amount UCAP that needs to be purchased to meet reliability criteria remains essentially unchanged. The increase in reserve margin is because on capacity basis the simulations indicate that 1 MW of wind is equivalent to approximately 0.2 MW to 0.3 MW of conventional generation. The capacity value equivalent of 1 MW of existing wind plants which include a mix of 65 and 80 meter towers has ranged between 0.14 MW and 0.23 MW. Therefore, it requires a lot more installed wind to provide the same level of UCAP as a conventional generator. This results in an increase in the installed reserve margin which is computed on an installed nameplate basis.

5.4.10. Summary of findings for Task 4

Task 4 resulted in a number of findings which are summarized below:

Because of their variable nature and limited dispatchablility, the addition of wind resources on a large scale basis will result in a system that is more variable than a system without the wind resources.

The increased variability which is measured in term of the net-load deltas (i.e., load minus wind) will result in a greater magnitude ramp event which the dispatchable generation will need to respond to.

The NYISO dispatch processes are already sufficient to reliably respond to the increase in the magnitude of the net-load ramps that result from the integration of up to 8 GW of installed wind studied.

As discussed above, the increased variability will result in increasing the amount regulation capacity that is procured to maintain compliance with reliability criteria.

The addition of wind will result in a reduction of the MW of fossil fuel fired capacity that is needed to operate the system but a greater percentage of the capacity that is committed will be committed to be available to respond to higher magnitude ramping events and produce less energy.

The addition of wind will not alter the NYISO's operating reserve requirement.

The reserve margin requirement will increase as the penetration of wind resource increases because wind has a lower availability relative to other resources and its unavailability is highly correlated.

[11] It should be noted that off-shore wind exhibits ELCC that is higher than on-shore wind because a greater percentage of the off-shore wind plants energy production occurs during peak hours. As an example, the GridView wind plant simulations based on 2006 wind data resulted in a 37.4% overall annual capacity factor (CF) for off-shore wind VS 34.3% for on-shore wind. However, the CF for off-shore wind plants during peak hours (the hours between 7am and 11 pm weekdays) was 39.7% for off-shore wind VS 32.5% for on-shore wind.

5.5. Results for Task 5 - Impacts of Wind Generation on Transmission Infrastructure:

5.5.1. Introduction:

The purpose of Task 5 is to evaluate the impact of the higher penetration of wind generation on system planning from a thermal, voltage and stability perspective. This analysis serves as the foundation for determining whether additional transmission infrastructure is needed to support higher penetrations of wind. The analysis of the need for additional transmission infrastructure is discussed under Task 7. The 2009 RNA Summer 2013 peak load case was utilized as the initial study base case. Two cases were prepared to represent 4000 MW and 6000 MW of nameplate installed wind capacity. The represented wind projects were determined by the NYISO interconnection queue as presented in Table 5-1 on page 13, and project interconnection representation data were obtained from the available Interconnection Studies. For each of these cases, a corresponding off-peak case was prepared for evaluating the impact of wind output during light load conditions. The peak load cases represent a NYCA load of 35,900 MW, and the off-peak cases represent 13,400 MW load plus 1,500 MW pumping load (Niagara and Gilboa).

Thermal transfer capability was assessed using the PSS™/MUST program. In addition to the sets of normal and emergency transfer criteria contingency events in the New York bulk transmission system, tower and bus contingencies in the local 115kV area transmission system were also evaluated in the vicinity of the wind project interconnections and key transmission corridors throughout the New York transmission system. Generation source subsystems were defined for wind projects (only), non-wind generation, and all generation, and evaluated by individual zone and groups of zones: West (A+B+C), and North (D+E). Changes in the transfer limits, transfer limiting elements, and limiting contingencies for the different export subsystems help to identify the transmission constraints that need to be modeled in the production simulations in Task 6. The base case power flow wind generation was initially dispatched at 20% or rated nameplate, and the transfer simulations were uniformly increased to 100% nameplate.

5.5.2. Initial Assessment of Transmission Constraints

The transfer limit results for the four power flow cases and 24 source subsystem combinations were compared to identify potential transmission constraints and if these constraints were a pre-existing transfer constraint, the result of wind generation (only), or combination of existing generation and new wind generation. Particular attention was given to constraints (limiting elements or events) that are unique to specific generation groups, individual projects, or load level. The analysis to determine limiting transmission facilities and contingencies monitored all New York transmission facilities >100kV, and evaluated critical line, bus and tower contingencies in the local area 115kV transmission system. This expanded contingency list aids in identifying where local area transmission constraints may be more limiting for individual projects or groups of projects within each Zone, and identifying local constraints that could be more limiting than typical EHV transmission system constraints.

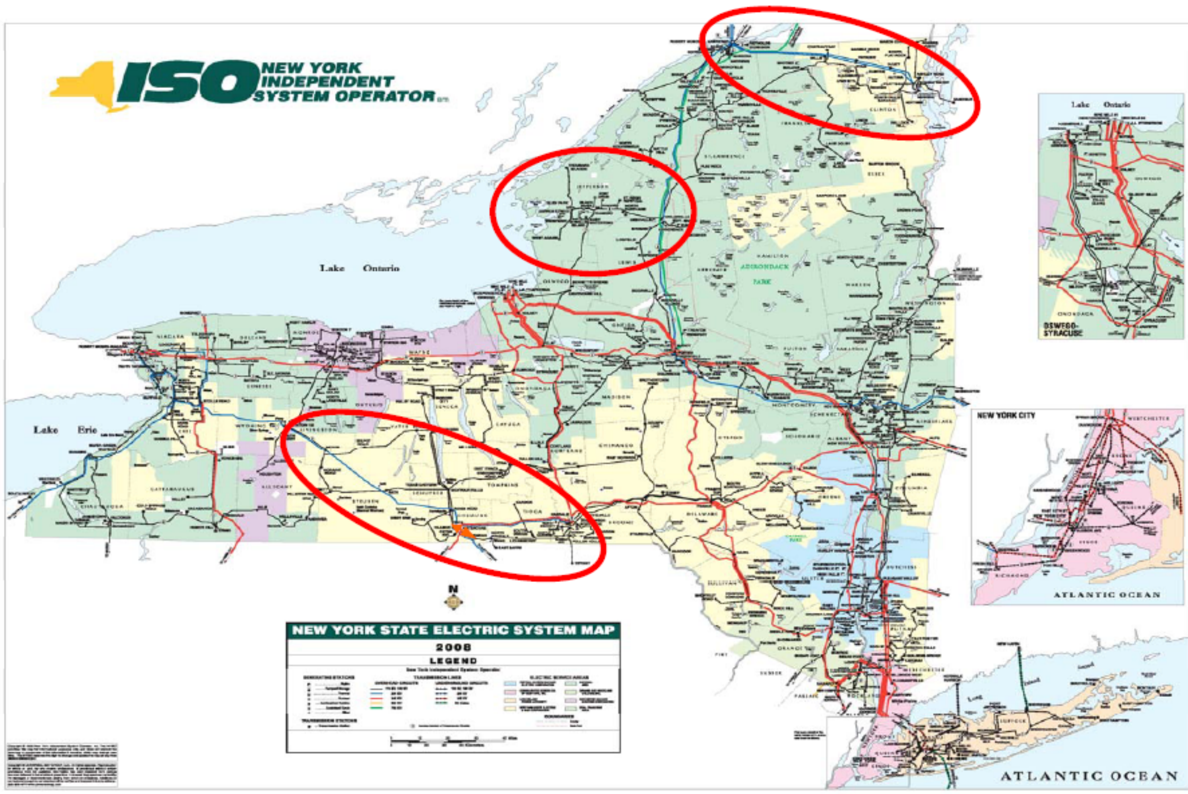


Figure 5.34: New York Transmission Map Displaying (circles) Where Local Transmission Facilities Limit Wind Plant Output

Zone A (West) – all wind projects in this zone can be uniformly increased to about 60-70% of total nameplate level before any transmission constraints are observed. Observed limitations include the Batavia –Golah 115kV for loss of a parallel Niagara – Rochester or Somerset – Rochester 345kV circuit; the actual transfer level is only slightly more limiting than the same constraint in the non-wind generation transfer case.

Zone B (Genesee) – transmission constraints occur at export levels equivalent to 25% above the combined nameplate of the projects.

Zone C (Central) – specific transmission constraints within this zone can be related to a specific project (or group of projects). The most significant constraint appears to be the projects in the vicinity of Bath 115kV being curtailed to as low as 45% nameplate by the local 115kV transmission in the peak load case with 6,000 MW wind; the constraint relaxes to 60% for the off-peak/light load scenario. Another group of projects (2 specific projects connected to the same local 115kV transmission circuit) are locally constrained to 65% nameplate (peak load, 6,000 MW wind) to 75% nameplate (peak, 4,200 MW wind). The group of projects connected along the 230kV path from Stolle Road to Hillside may also be limited by tower contingencies at either Stolle Road or Hillside 230kV at about 65% nameplate. The 115kV path between Hillside and Oakdale is both a constraint to the wind projects and general west-to-east transfers for contingencies involving EHV transmission (230kV and 345kV) at for wind generation levels of 35% nameplate (6,000 MW wind cases) to 50% nameplate (4,200 MW wind cases).

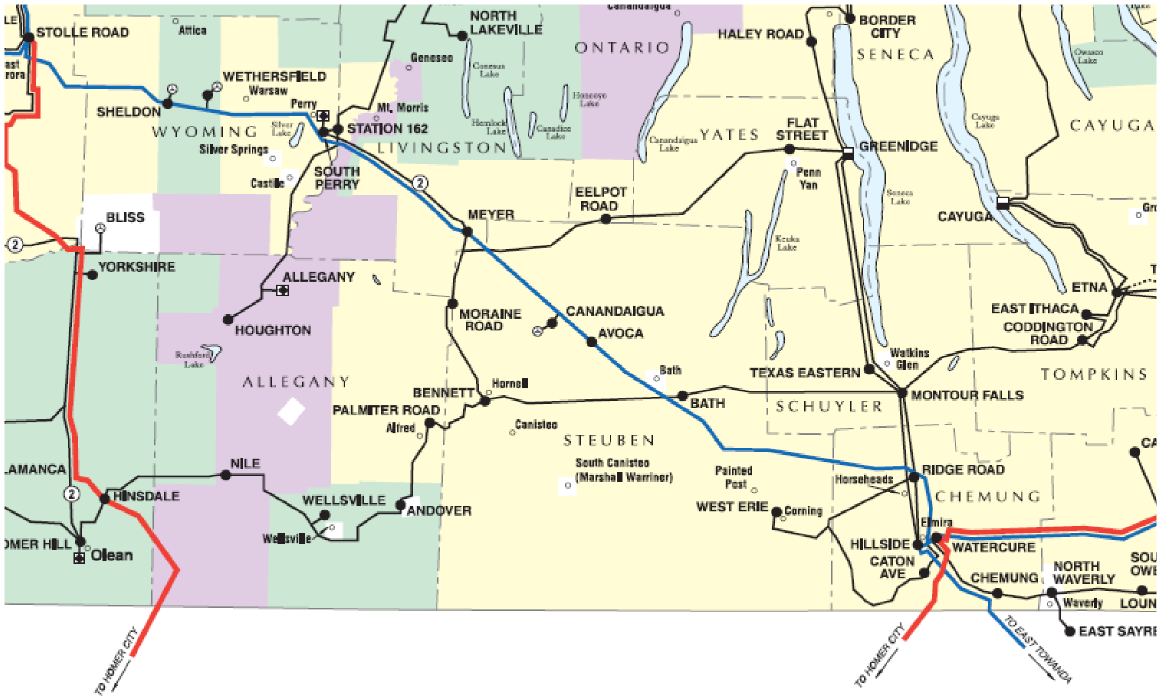


Figure 5.35: Transmission Facilities Zones A, B and C

Zone D (North) – the transmission constraints – limiting facilities and limiting contingencies – in the North zone are generally centered around the Willis 230kV transmission and connections to the 115kV. The 230/115kV transformers at Plattsburgh limit corresponding projects connected to the same 230kV circuit from Willis for the opening of the Willis end of that line at 40-50% of nameplate. The next constraint is the Willis-Malone-Colton 115kV for the loss of the Moses-Willis 230kV tower at 50-70% nameplate.

Zone E (Mohawk) – the group of three (3) projects radially connected to Coffeen St. 115kV (vicinity of Watertown) are limited by local 115kV transmission radial from the interconnection point to Coffeen St. (Lyme Tap – Coffeen St. and Rockledge Tap – Lyme Tap 115kV) at 35% nameplate. Those 3 projects plus a 4th project connecting at Black River 115kV are collectively constrained by the Lighthouse Hill -- Mallory 115kV for loss of tower Taylorville – Boonville 115kV or loss of tower Black River – Taylorville 115kV; or a Black River – Taylorville 115kV circuit limiting for the loss of tower Black River – Lighthouse Hill 115kV. These constraints are generally the same for both load levels, however, the single-circuit Taylorville – Boonville appears more limiting for non-wind (hydro and thermal) sourced transfer simulation.

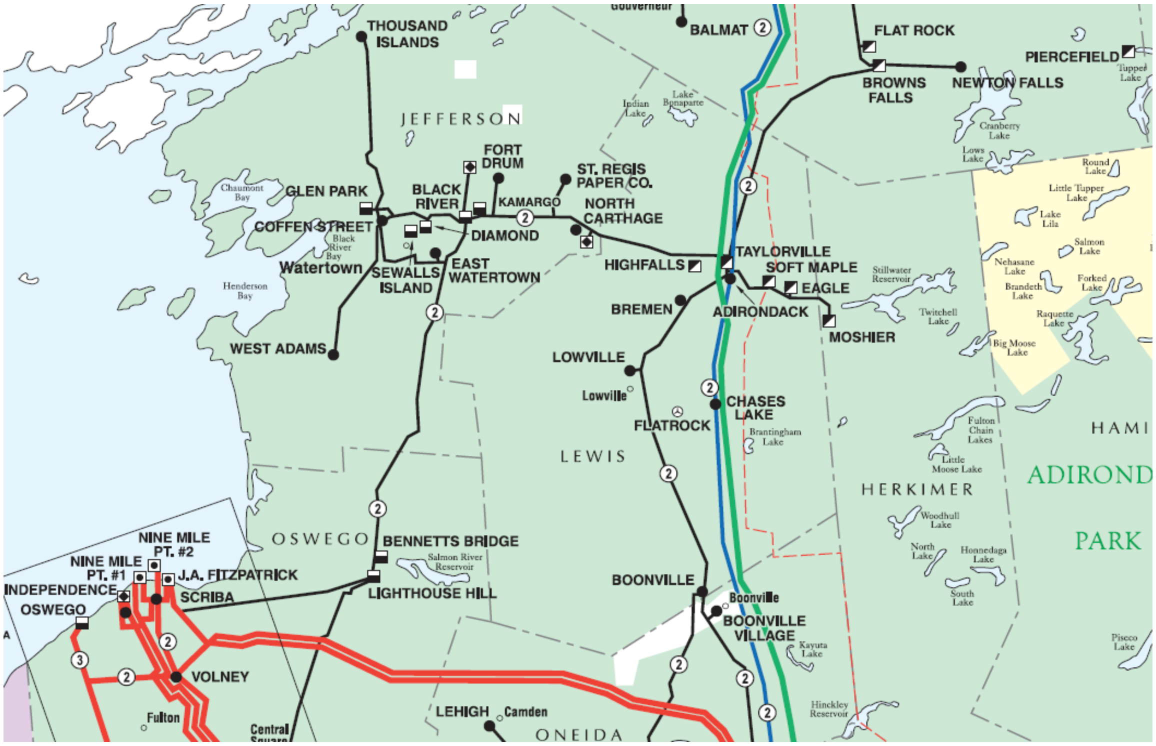


Figure 5.36: Transmission Facilities Zones D and E

Zone F (Capital) – all transmission constraints are significantly higher than available wind capacity and EHV transmission constraints are more limiting in the non-wind transfer simulations.

5.5.3. Evaluation of Multiple Zone Sources

Western New York wind (Zones A, B, and C) – the transmission constraints observed are typical for west-to-east transfers. These include Hillside – Oakdale 115kV (40%), and Lockport – Mortimer 115kV (53%), and Delhi – Fraser Tap 115kV (35%; light load). Lockport – Mortimer 115kV constraints are related to projects connecting east of Lockport 115kV, however the limitation is responding to loss of transmission elements between the wind project interconnection point(s) and the Mortimer (Rochester end) terminal. Although there is a wind project in the vicinity of the Delhi constraint, it is actually in Zone E and not participating in this transfer simulation; this limitation is based on the contingency loss of tower at Oakdale 345kV (Oakdale – Lapeer and Oakdale – Fraser).

Northern New York wind (Zone D, and E) – the combined wind resources in these two zones are limited by the same Willis exit (Zone D projects) and Watertown area transmission constraints (Zone E projects) that were observed in the individual Zone analyses. Although the constraints and projects affected are independent, this occurs at the combined output of 30-40% nameplate level for both load levels and both wind capacity levels.

Since all wind resources (within each defined zone) are participating equally and coincidentally, the constraints may tend to exaggerate the potential for bottling of wind resources as the commitment/dispatch of local thermal resources is not being modified by the presence of the wind generation. The set of transmission contingencies and monitored elements were provided for the analysis conducted in Task 6. The production cost simulation model is used to evaluate the impact of those constraints in the commitment and dispatch process on the potential for bottling of wind production or overall system congestion of wind generating plants.

5.5.4. Transient Stability Analysis

Part of the overall evaluation of increased level of wind generation resources in the NYCA is to identify potential impact on the stability performance of the system. The evaluation should consider on- and off-peak load levels with highest expected wind production levels consistent with those load periods.

The NYCA Central East Interface was selected as the primary reference to evaluate the impact of high wind penetration on NYCA system stability performance. Central East stability performance has been shown historically to be key a factor in the dynamic performance of the NYCA as well as the northeastern portion of the Interconnection in general. Selecting this interface also recognizes that the majority of wind projects are located in Zones A through E, the source or "upstream" side of the Central East interface, and that the lower cost wind generation resources would tend to displace the downstate generation in Zones G through K (SENY).

The Production Cost simulations were reviewed and the hours with the highest dispatch level of wind generation were identified within either off-peak or on-peak hours. These cases represent the highest expected wind production coincident with the load. The actual load, generation commitment and dispatch were obtained from the Production Cost simulation results and imported into the powerflow model. Based on the commitment of the Oswego Complex generation, the Central East transfer level was increased to its margin transfer level for that configuration by increasing all committed generation in the Oswego Complex to maximum capability and additional generation in Zones A through E until the Central East margin test level was achieved. A third case was identified that represented off-peak load with high wind production and no Sithe/Independence generation committed. These 3 cases form the basis of the stability analyses.

Table 5-12: Powerflow Case Summaries

	Off-Peak/High Wind (with Sithe Units)	On-Peak/High Wind	Off-Peak/High Wind (without Sithe units)
NYCA Load + Loses	17202 MW	33559 MW	16113 MW
Total Wind Name Plate	7974 MW	7974 MW	7974 MW
Total Wind Dispatch	6572 MW	3400 MW	6326 MW
Central East Interface Flow	3399 MW*	3390 MW*	3289 MW*
Oswego Complex Dispatch	3148 MW	5087 MW	2620 MW
Oswego Units Commitment	3/5	5/5	3/5
Sithe Units Commitment	4/6	6/6	0/6

* The stressed Central East interface flow is ~110% of Central East interface stability transfer limit based on the commitment of Oswego Complex and Sithe/Independence units.

A subset of contingencies was selected for the Central East interface; these contingencies represent the most severe normal criteria fault tests in NYISO Planning and Operations evaluations of Central East/Total East stability performance.

Table 5-13: Description of Contingencies Selected for Testing

ID	Contingency
CE01AR	3ph NC@Edic 345/Edic – N. Scotland #14 with automatic reclosing
CE02	3ph NC@Marcy 345/Marcy – N. Scotland #18
CE07AR	LLG NC@Edic 345/Edic/Marcy EF40/UCC41 with automatic reclosing
CE08AR	LLG NC@Coopers Corners 345/Coopers Corners #33/UCC41
CE12	3ph NC@N. Scotland 345/N. Scotland – Edic #14
CE15	SLG-stk@Marcy 345/Marcy #19/UE1-7
CE18AR	LLG NC@Rock Tavern 345/ Rock Tavern CCRT34/CCRT42 with automatic reclosing

The set of contingencies were simulated using the Siemens/PTI PSS/e program. All simulations were stable, and there were no indications of tripping of wind generation resources due to the severity of the fault or frequency or voltage excursions.

Table 5-14: Simulation Results

ID	Off-Peak/High Wind (with Sithe Units)	On-Peak/High Wind	Off-Peak/High Wind (without Sithe units)
CE01AR	S	S	S
CE02	S	S	S
CE07AR	S	S	S
CE08AR	S	S	S
CE12	S	S	S
CE15	S	S	S
CE18AR	S	S	S

S – Stable

Observations

The NYCA (and the Interconnection) system demonstrated a stable and well damped response (angles and voltages) for all the contingencies tested on high wind generation on-peak and off-peak cases. There is no indication of units tripping due to over/under voltage or over/under frequency. The off-peak case without Sithe/Independence units showed a more oscillatory behavior than the corresponding off-peak case with Sithe/Independence units in service. This is an expected result as these units are equipped with Power System Stabilizers (PSS) and the PSS' benefit to system damping and overall performance is recognized in the Central East Interface Stability Limits tables. Overall, at the high wind generation levels, the results of the simulations demonstrate that there is no adverse impact on NYCA system stability performance for both on-peak and off-peak conditions.

5.6. Results for Task 6 - Production Simulation Analysis:

5.6.1. Introduction

A simulation of security constrained economic dispatch (SCED) was performed for the NYCA system in order to determine the impacts of various levels of wind generation on the balance of the system generation, primarily fossil fuel generation. ABB's GridView was the software that was utilized to simulate SCED. The modeling assumptions used in the simulations were, for the most part, those used in the CARIS except for those modifications required to conduct the wind study. The primary focus of the simulations is not to determine the economic value of wind generation, but to answer the following questions:

Question 1: What are the locational based marginal prices (LBMP) for energy or spot prices impact of introducing a large amount of "price takers" to the system?

Question 2: What types of generation are displaced such as coal, oil or gas?

Question 3: What is the change in production costs?

Question 4: What is the reduction in emissions?

Question 5: What is the change in imports and exports?

Question 6: What is the change in system congestion costs and uplift?

Question 7: What is the change in the capacity factors of the thermal plants?

These simulations were also used to support the evaluation of the ramping issue that was discussed in Task four as well as determining the level of wind bottling.

5.6.2. Locational Based Marginal Prices (LBMP)

Figures 5.37 through 5.45 present the LBMPs that result from the simulations of the different levels of installed wind studied for 2013 and 2018. Results are presented for the NYCA system, by superzones, and for dispatch sensitivities. The simulations were conducted utilizing the CARIS economic assumptions. The first set of LBMP results are for 2013.

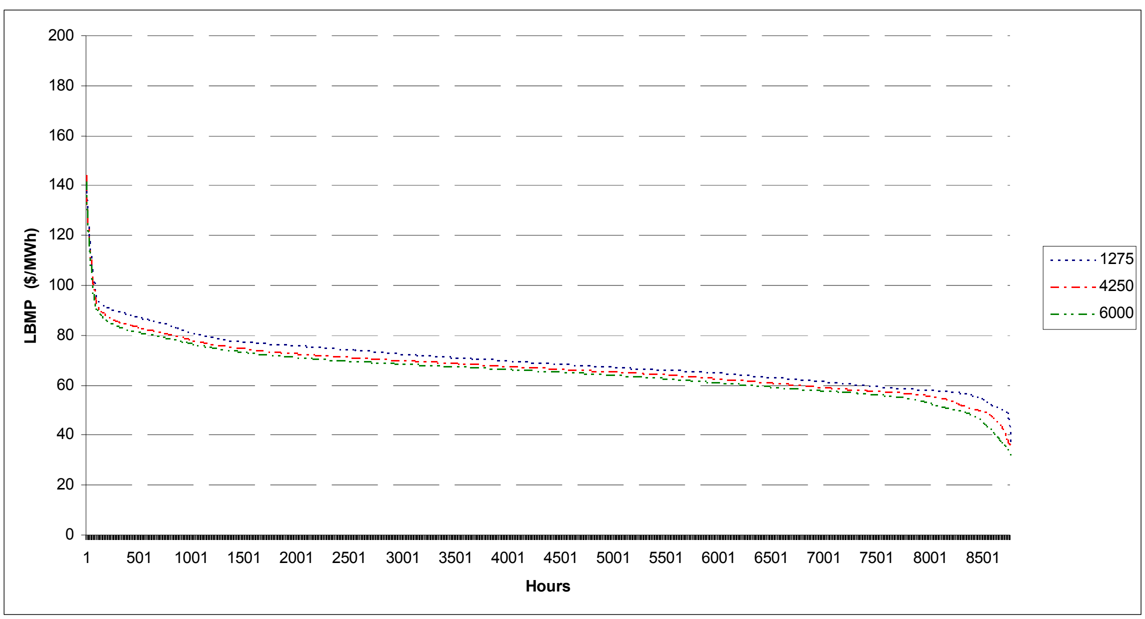


Figure 5.37: LBMP for 2013 VS Wind Penetration for NYCA

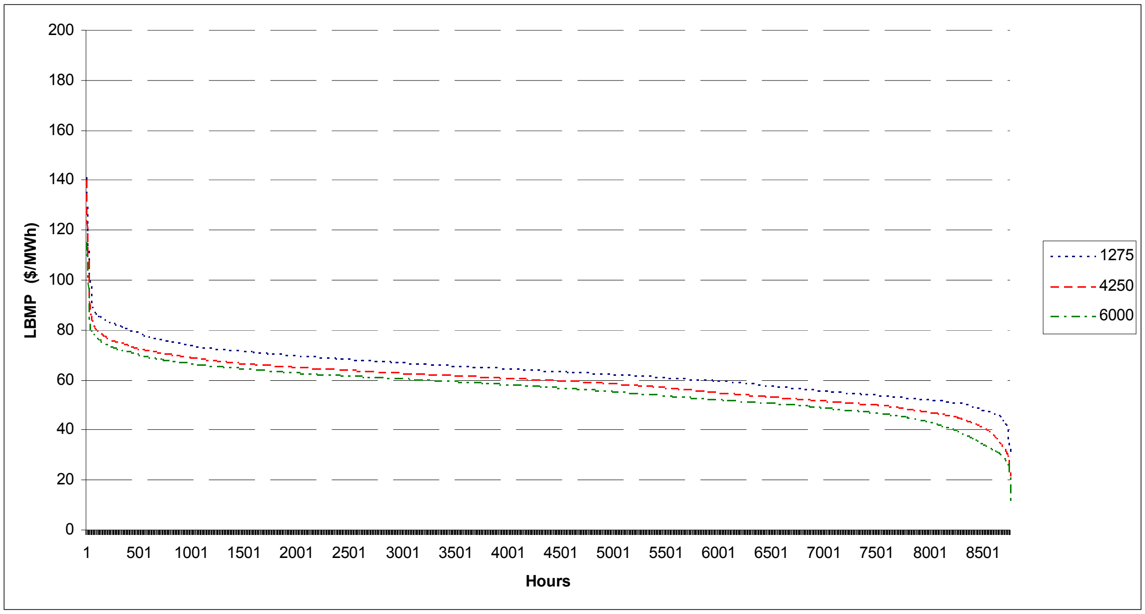


Figure 5.38: 2013 LBMP VS Wind Penetration for Superzones A-E

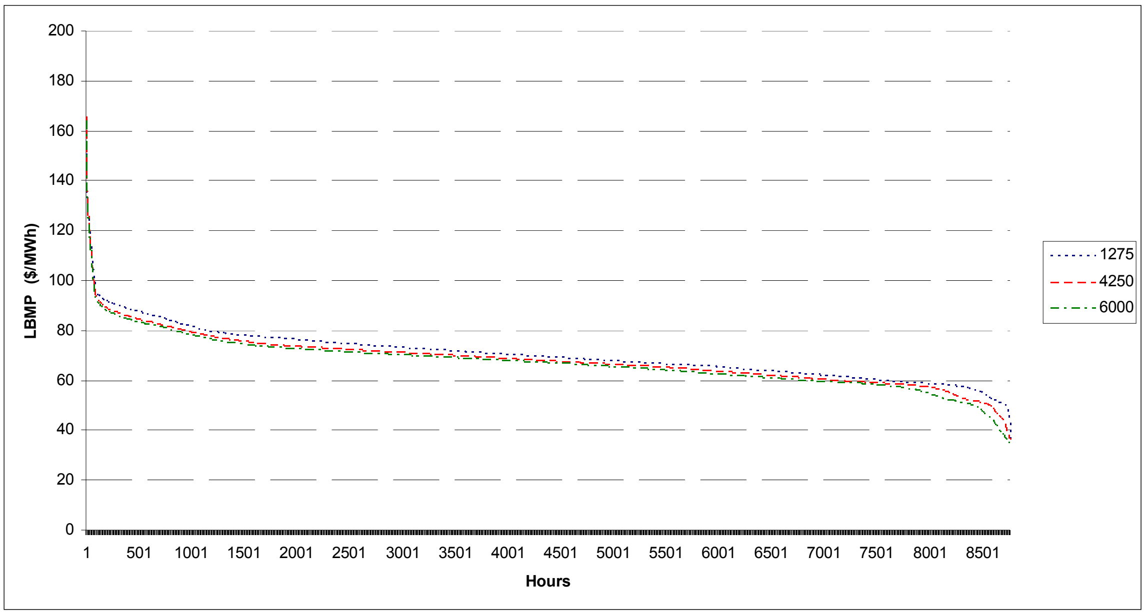


Figure 5.39: 2013 LBMP VS Wind Penetration for Superzones F-I

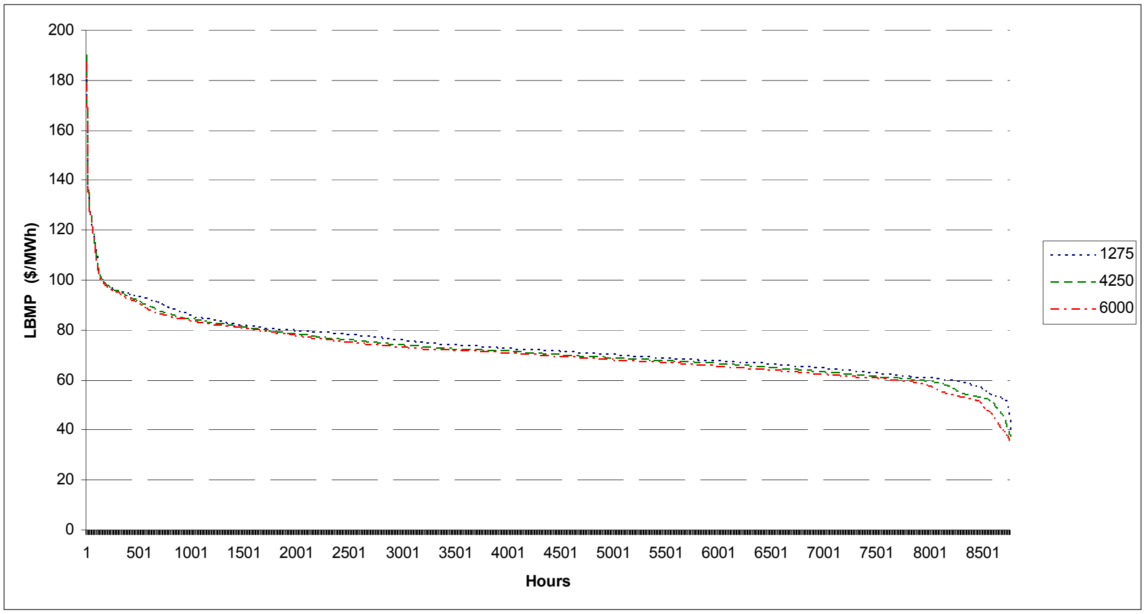


Figure 5.40: 2013 LBMP VS Wind Penetration for Superzones J-K

Table 5-15: Summary of Average LBMP for 2013

Zone	Average LBMP ($/MWh) by Installed Nameplate Wind		
	1,275 MW	4,250 MW	6,000 MW
System	69.5	66.8	65. 1
Zone A-E	63.5	58. 9	56.0
Zone F-I	70.2	68.1	66. 9
Zone J-K	73. 8	71. 7	70. 7

The next set of graphics presents the results for 2018. The results for 2018 include two additional sensitivities. The simulations assume that the wind that is committed is the wind that is available for economic dispatch. To test the impact on prices of an error in the wind commitment, two sensitivities were conducted for the 8 GW of wind scenario. The first sensitivity was the extreme case which did not commit for wind but allowed it to generate during economic dispatch while the second was to simulate the amount of wind that generated during economic dispatch to be available with a 10% mean absolute percent error (MAPE) when compared with the committed wind.

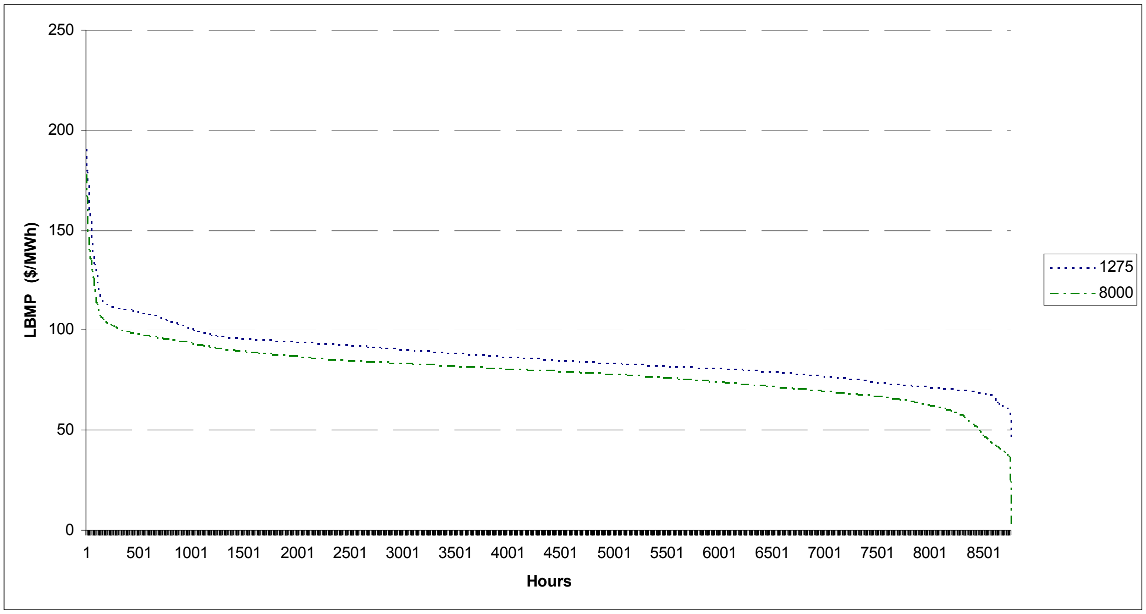


Figure 5.41: 2018 LBMP VS Wind Penetration for the NYCA

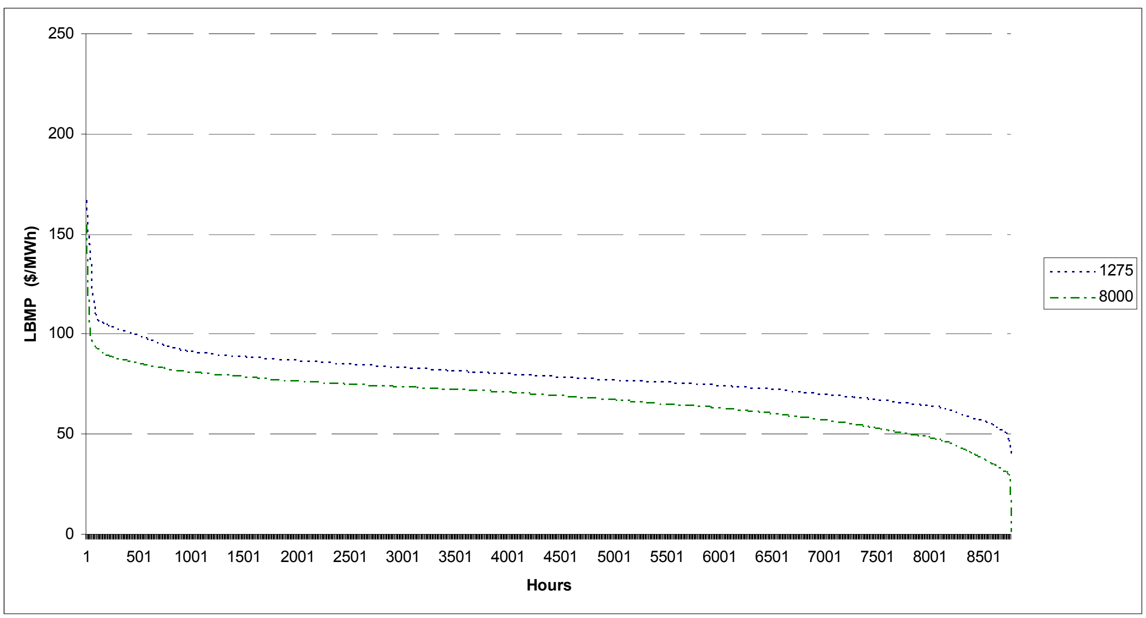


Figure 5.42: 2018 LBMP VS Wind Penetration for Superzones A-E

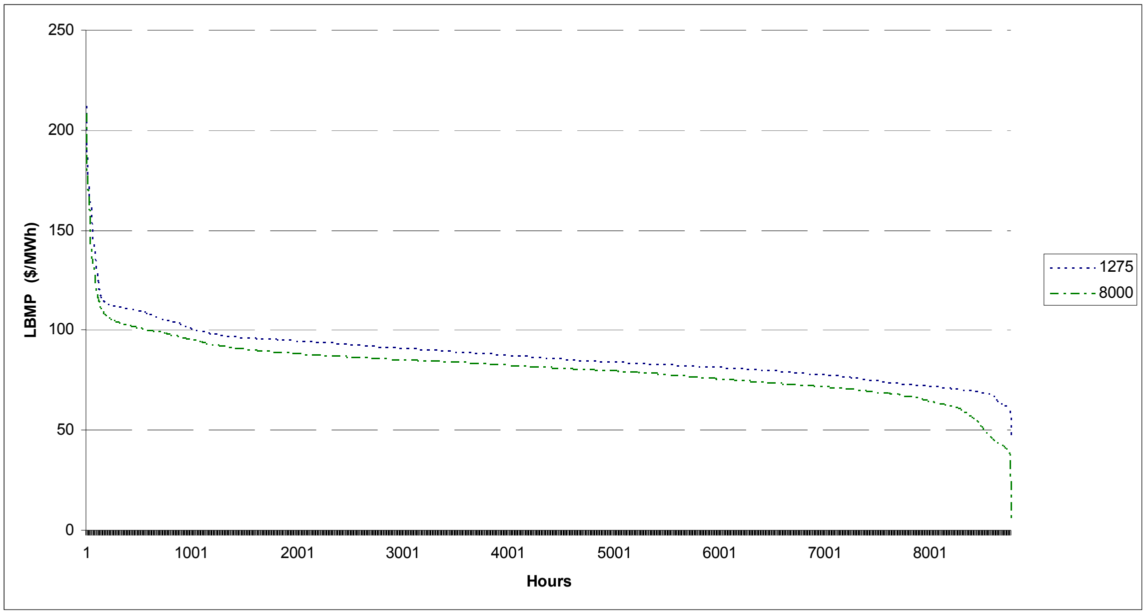


Figure 5.43: 2018 LBMP VS Wind Penetration for Superzones F-I

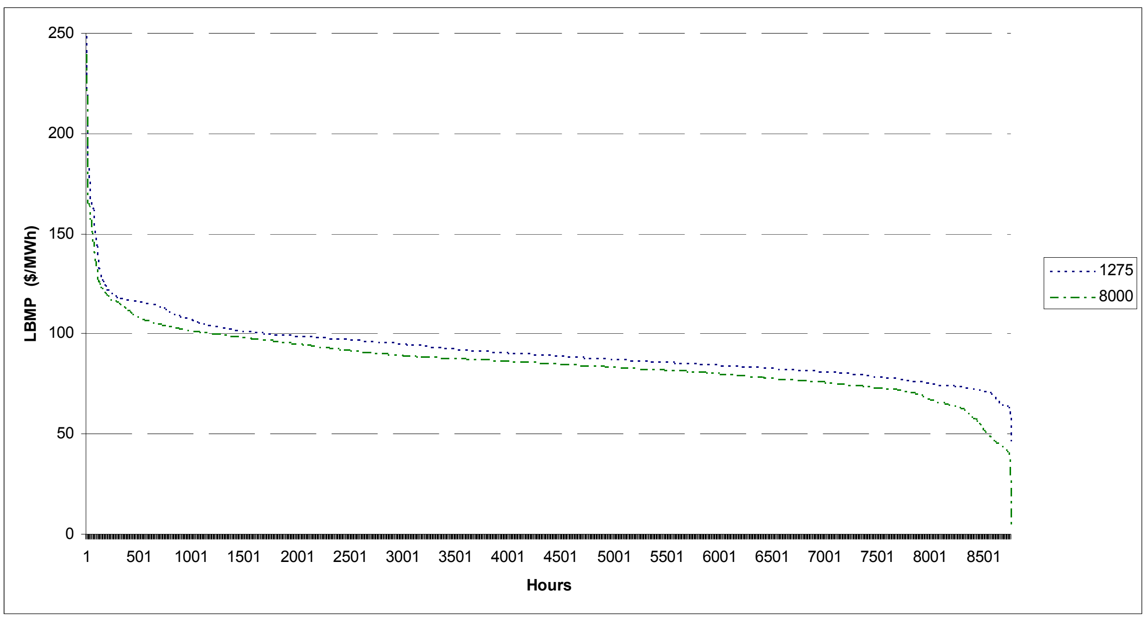


Figure 5.44: 2018 LBMP VS Wind Penetration for Superzones J-K

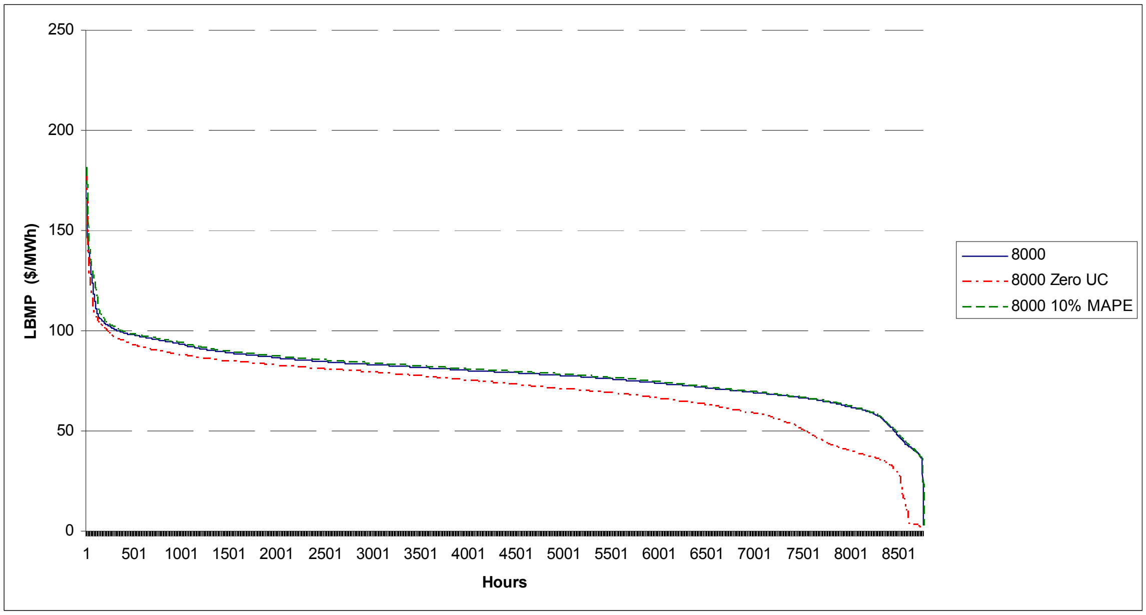


Figure 5.45: 2018 LBMP VS Wind Penetration for NYCA for the no Unit Commitment and 10% MAPE Commitment Sensitivity

Table 5-16: Summary of Average LBMP for 2018

Zone	Average LBMP ($/MWh) by Installed Nameplate Wind			
	1,275 MW	8,000 MW	No Commitment	10% MAPE
System	86.6	78.7	70.1	79.2
Zone A-E	79.1	67.2	57.5	67.9
Zone F-I	87.3	80.8	71.3	81.2
Zone J-K	91.4	85.6	78.0	85.9

Summary of Findings for LBMP:

What is important in this analysis is not the nominal value of the prices but the overall trend of the prices. The production cost simulations indicate that as significant amounts of essentially zero production cost generation is added to the resource mix, which participate as price takers, LBMP or spot prices decline as expected. For the 2018 simulations, the NYISO average LBMP prices are 9.1% lower for the 8 GW wind scenario when compared to the base case or 1,275 MW installed wind case. The reduction from the base case when compared to the 10% MAPE sensitivity is 8.5%. The dispatch sensitivities indicate the impact of incorporating wind into the commitment process and the how forecast error of wind resources can affect prices. Also, note the LBMP price impacts are greatest in the superzones where the wind generation is located and tends to increase the price spread between upstate, where the wind resources are primarily located in the study, and downstate which imply increasing congestion costs.

The decline in spot prices is generally a positive development for buyers but will result in lower energy revenues and energy production for dispatchable generation. The ultimate impact of these lower LBMPs involves a complex set of issues which are interrelated with other aspects of the NYISO market structure and design. The study of these interactions was beyond the scope of this report and, therefore, was not analyzed in this report.

5.6.3. Fuel Types Displaced by Wind Generation

Figures 5.46 through 5.53 present the results from the simulations that display what fuels are displaced by the introduction of wind generation into the resource mix.

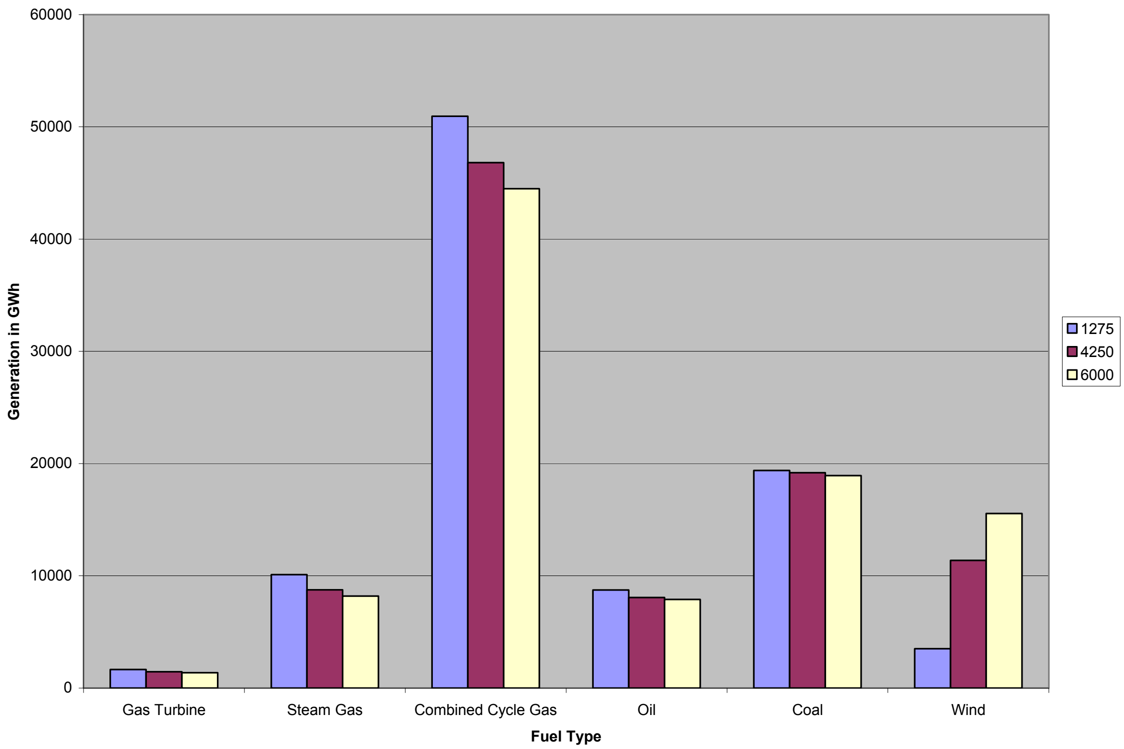


Figure 5.46: Fuel Types Displaced for 2013 for the NYCA

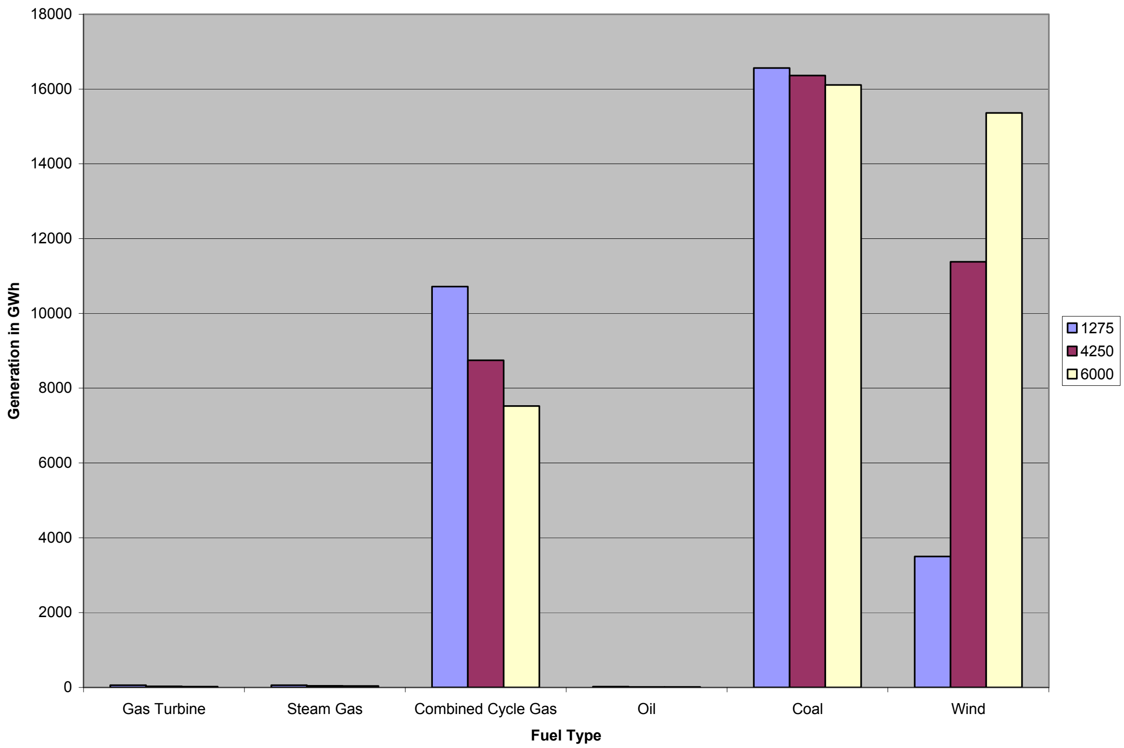


Figure 5.47: Fuel Types Displaced for 2013 for Superzone A-E

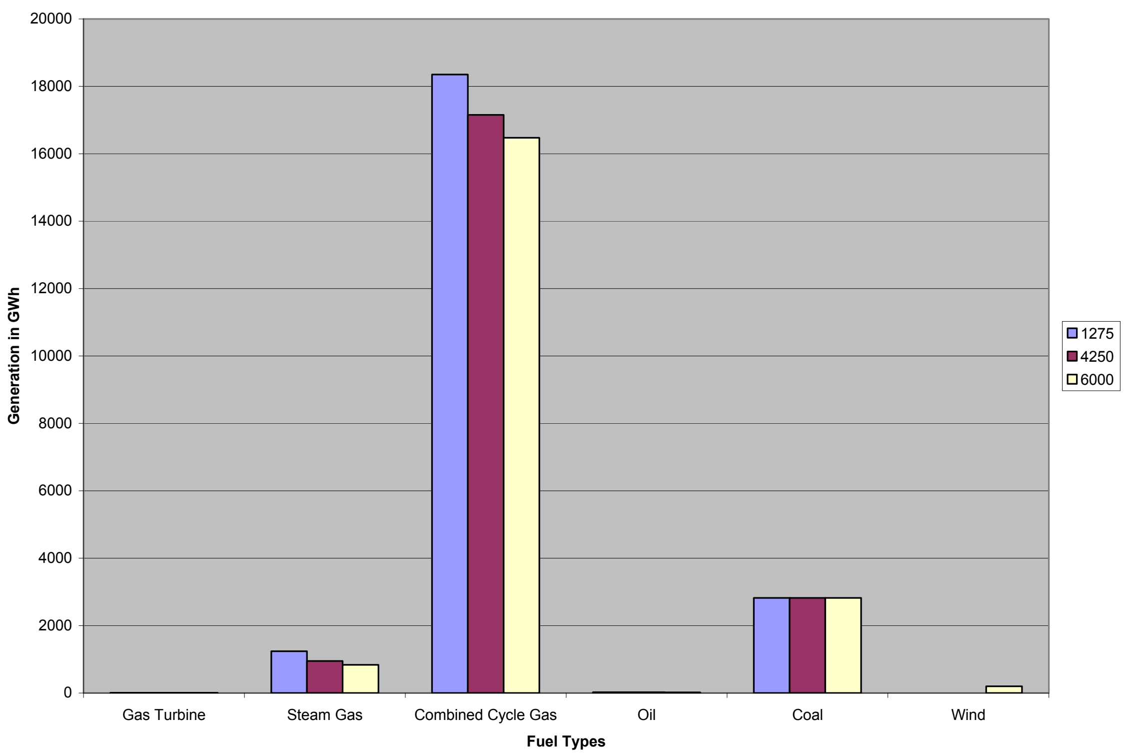


Figure 5.48: Fuel Types Displaced for 2013 for the Superzone F-I

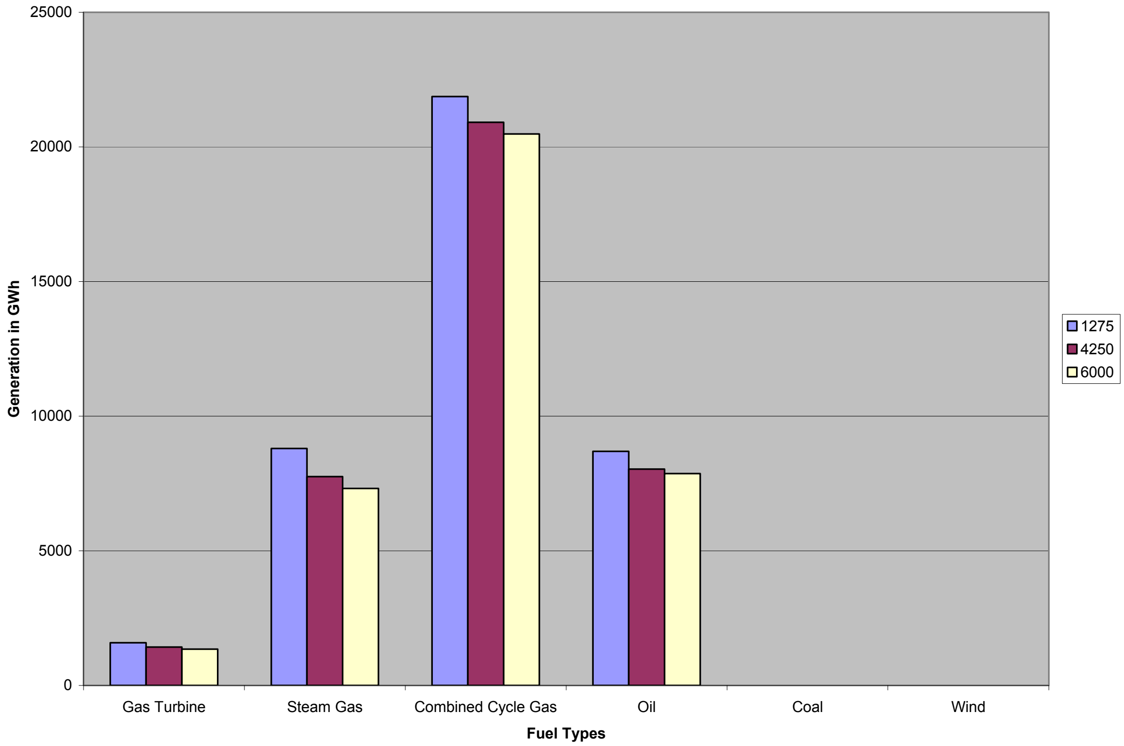


Figure 5.49: Fuel Types Displaced for 2013 for the Superzone J-K

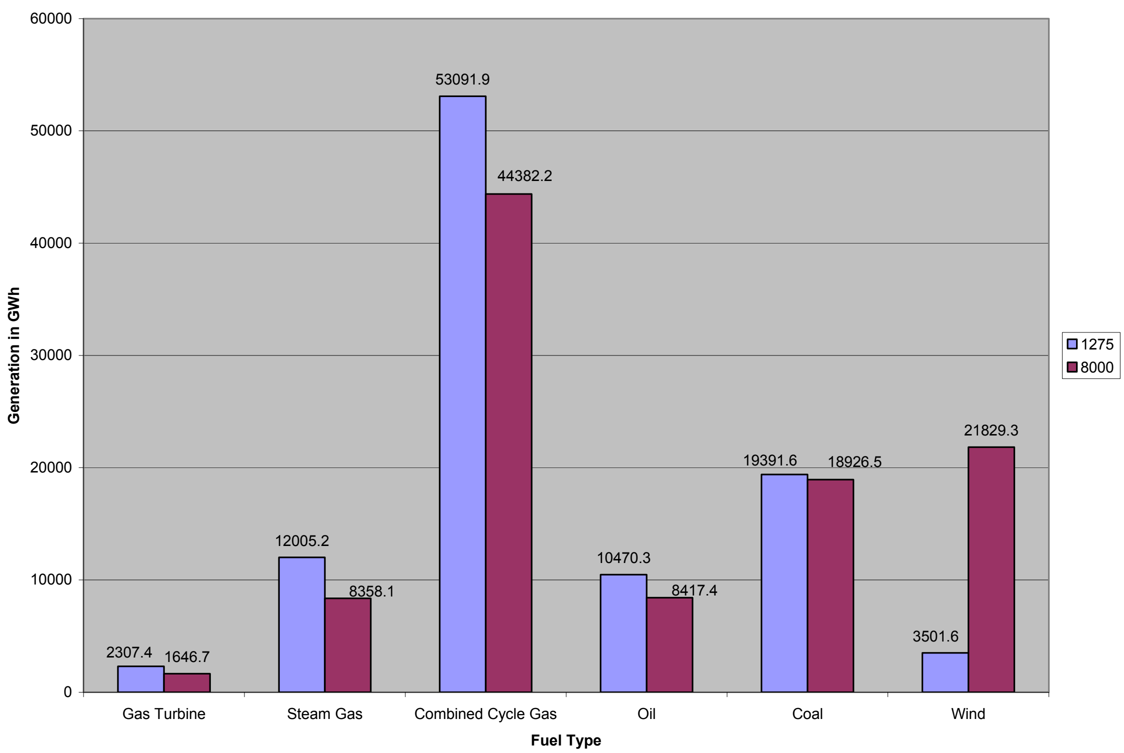


Figure 5.50: Fuel Types Displaced for 2018 for the NYCA

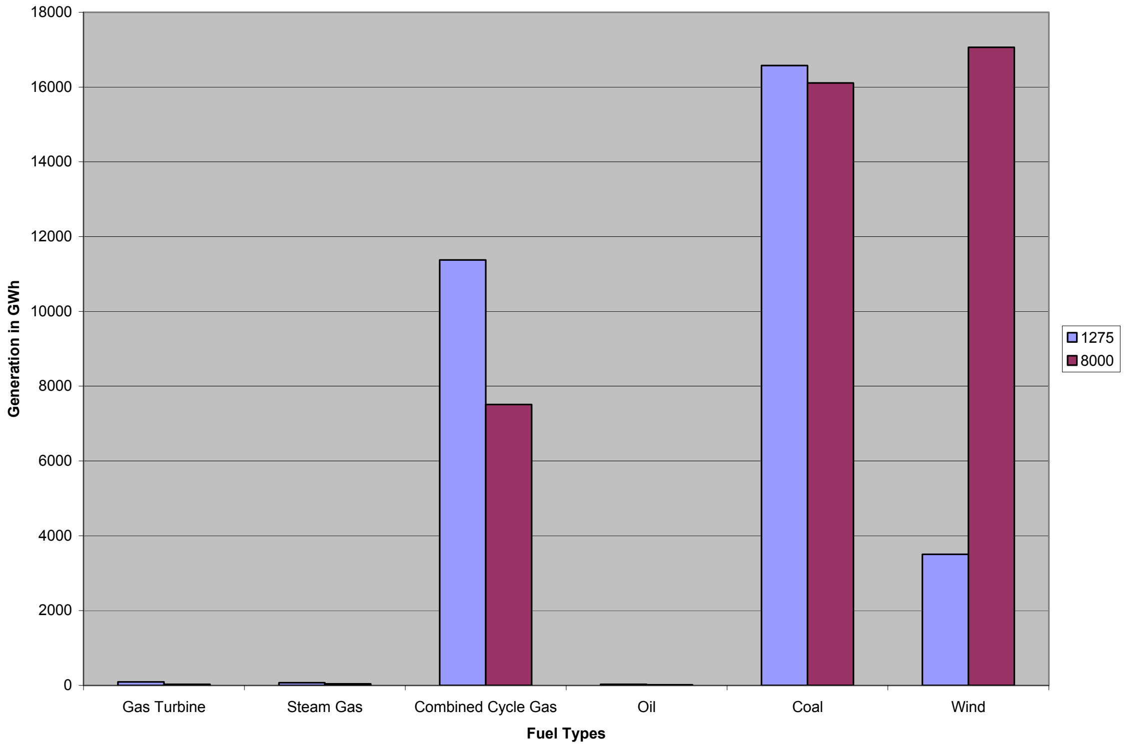


Figure 5.51: Fuel Types Displaced for 2018 for the Superzone A-E

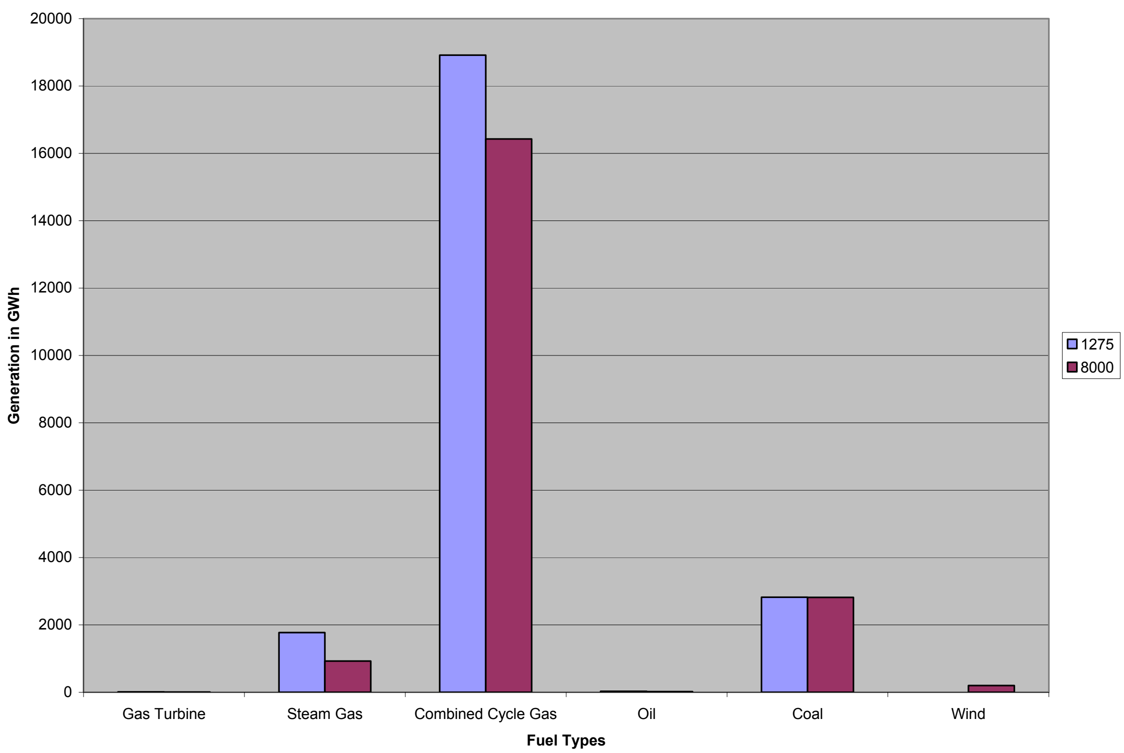


Figure 5.52: Fuel Types Displaced for 2018 for the Superzone F-I

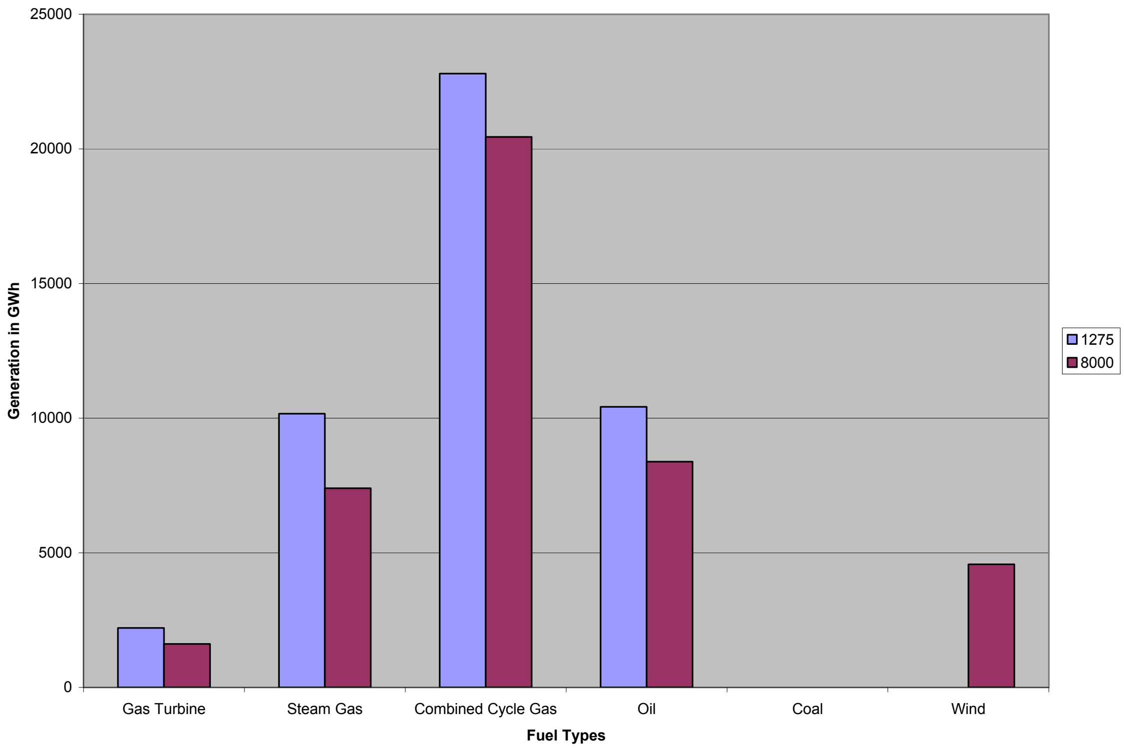


Figure 5.53: Fuel Types Displaced for 2018 for the Superzone J-K

Summary of Findings for Fuel Displacement:

The primary fuel displaced by increasing penetration of wind generation is natural gas. For the simulations with 8 GW of wind with 2018 loads, the total amount of fossil fired generation displaced was approximately 15,500 GWh. Gas fired generation accounted for approximately 13,000 GWh or approximately 84% of the total, while oil and coal accounted for approximately 2,050 GWh and 465 GWh respectively or approximately 13% and 3% of the total fossil generation displaced.

5.6.4. Wind Generation Impact on System Production Costs

The addition of wind resources with virtually zero marginal costs to the NYCA resource mix will result in the reduction of overall system production costs. The Figures 5.54 and 5.55 present the results for the impact of wind generation on system production costs as the level of installed wind generation increases.

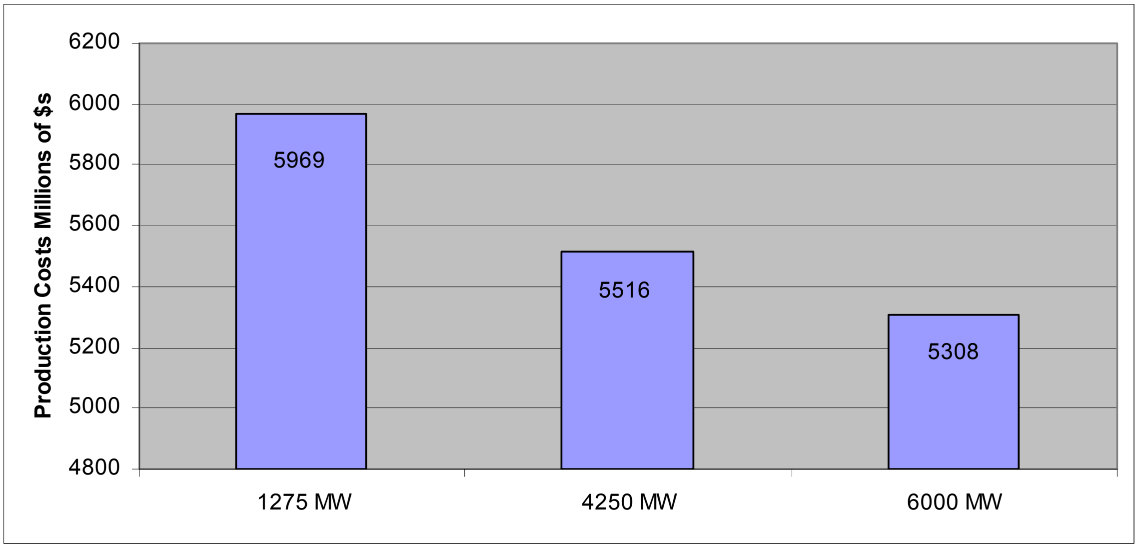


Figure 5.54: Change in Production Costs for 2013 as the Level of Installed Wind Generation Increases

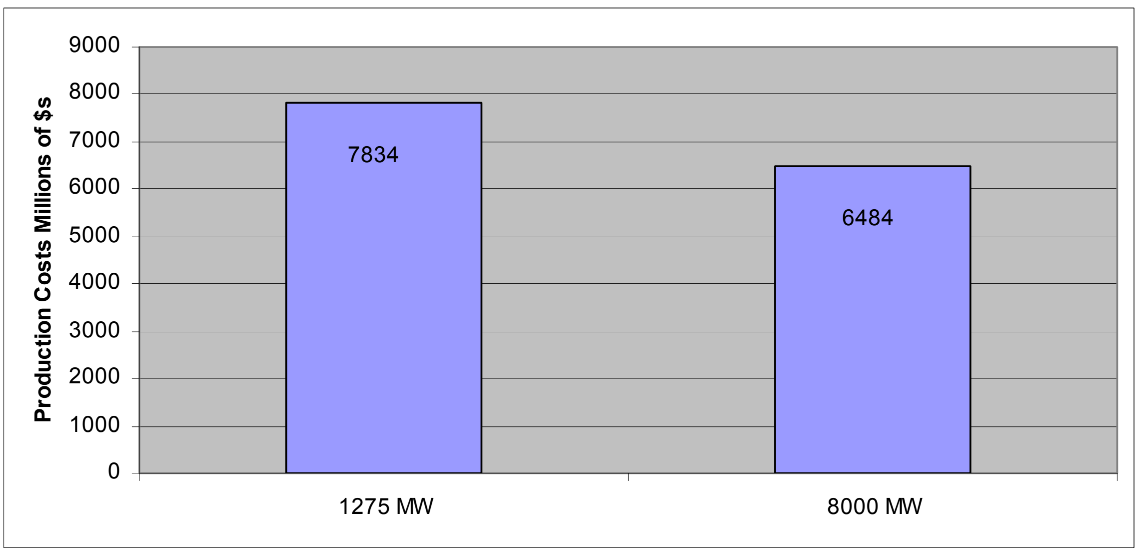


Figure 5.55: Change in Production Costs for 2018 as the Level of Installed Wind Generation Increases

Summary of Findings for Wind Generation Impact on System Production Costs

As the amount of wind generation increases, the overall system production costs decrease. For the 2013 study year, the production costs drop from the base case total of almost $6 billion to a level of approximately $5.3 billion for the 6,000 MW wind scenario. This represents a drop of 11.1% in production costs. For the 2018 study year, the production costs drop from the base case total of almost $7.8 billion to a level of approximately $6.5 billion for the 8,000 MW wind scenario. This represents a drop of 16.6% in production costs.

5.6.5. Wind Generation Impact on Emissions

Production of electricity by wind generators is emissions free. The Figures 5.56 through 5.61 display the changes in emissions for the New York power grid for CO_2, NOx and SO_2 as a function of increasing wind penetration.

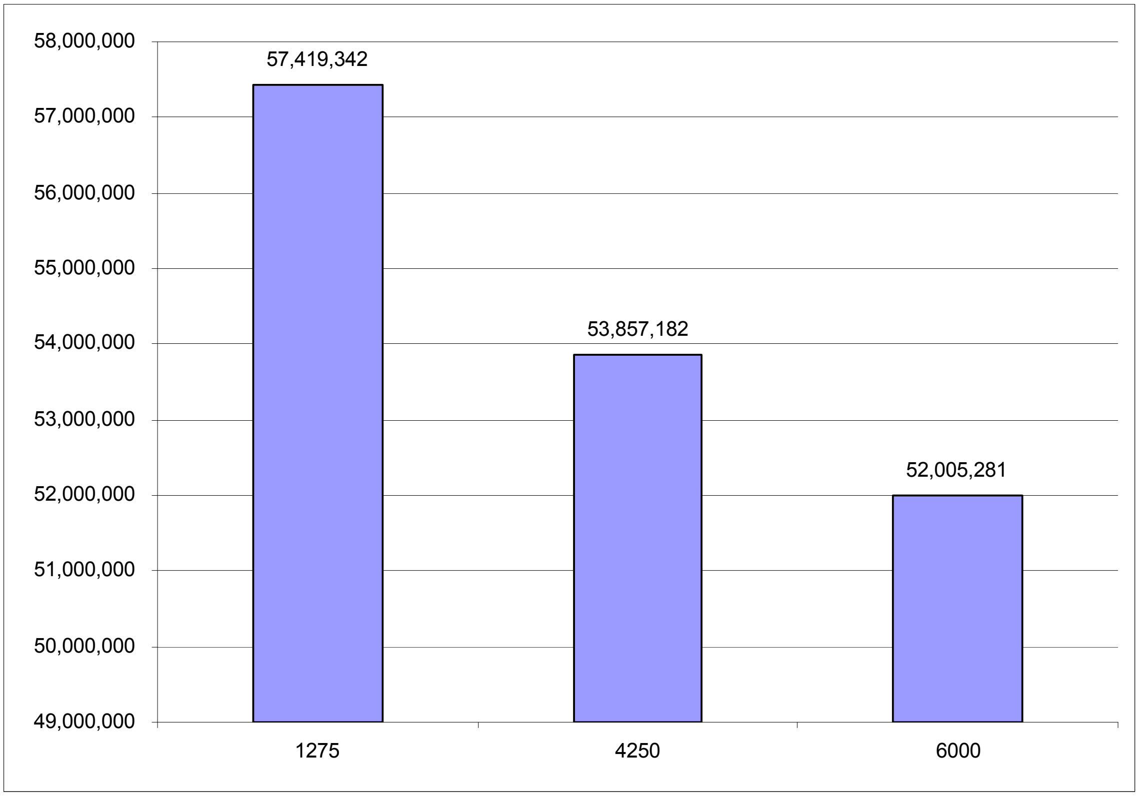


Figure 5.56: Reductions in CO_2 (short tons) as Wind Generation Increases for 2013

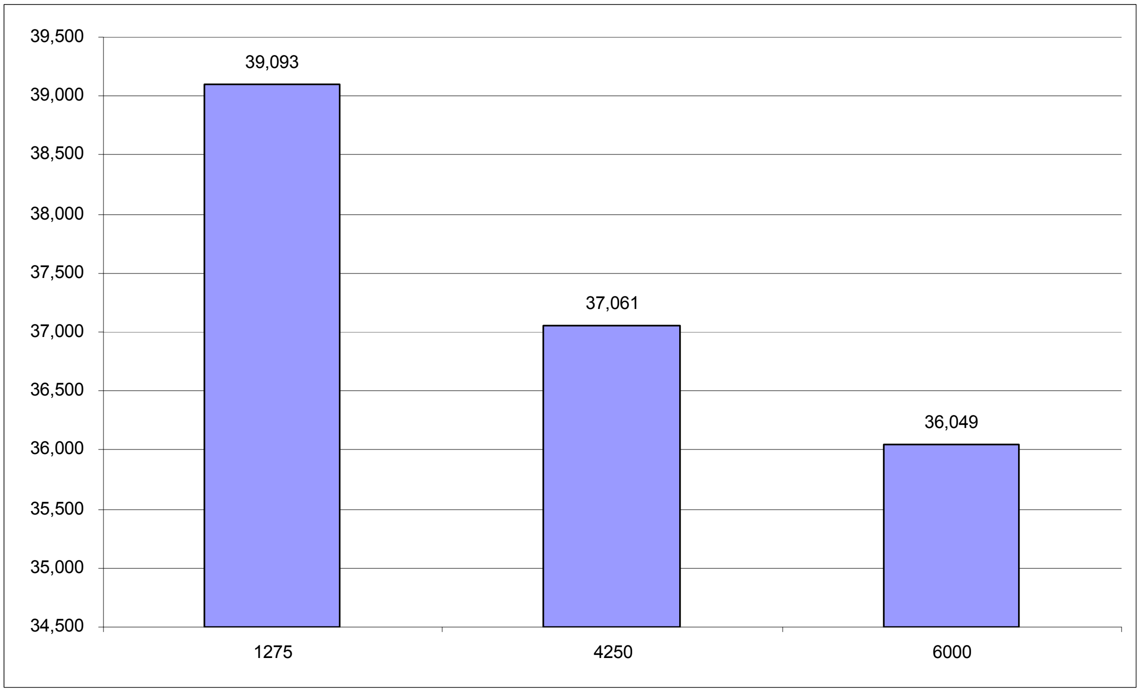


Figure 5.57: Reductions in NOx (short tons) as Wind Generation Increases for 2013

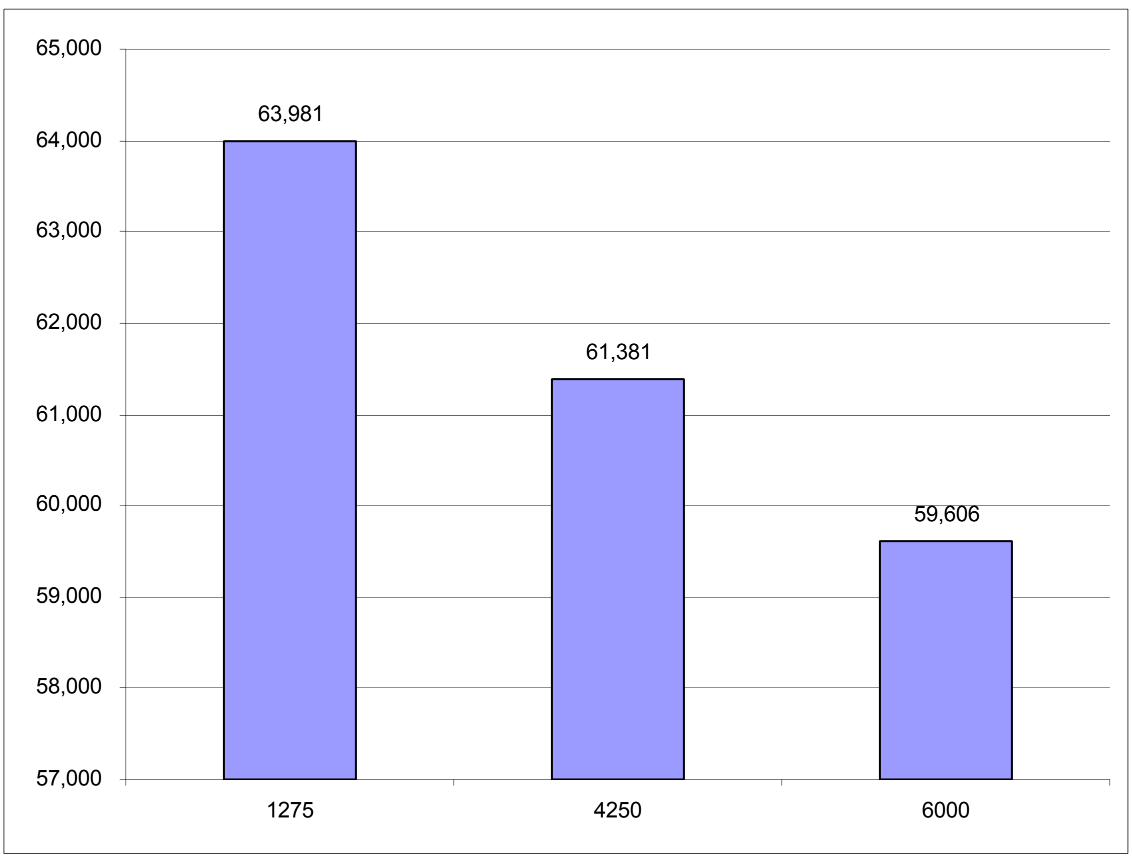


Figure 5.58: Reductions in SO_2 (short tons) as Wind Generation Increases for 2013

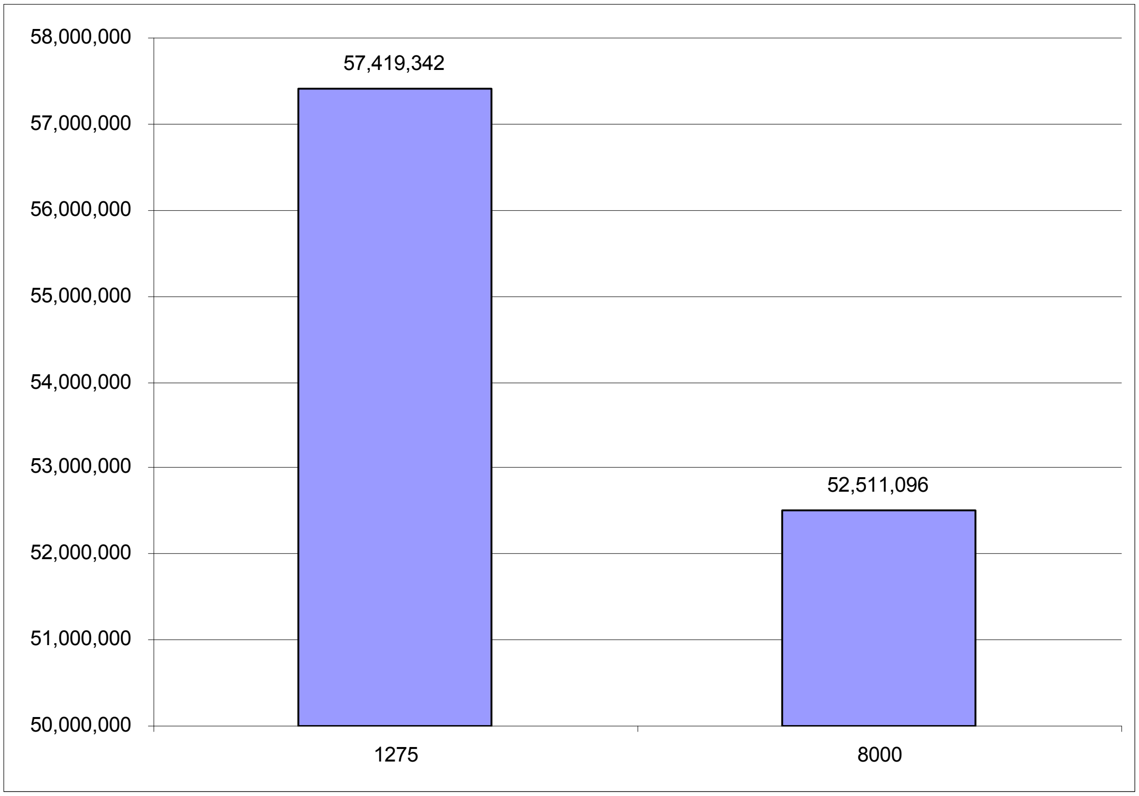


Figure 5.59: Reduction in CO_2 (short tons) as Wind Generation Increases for 2018

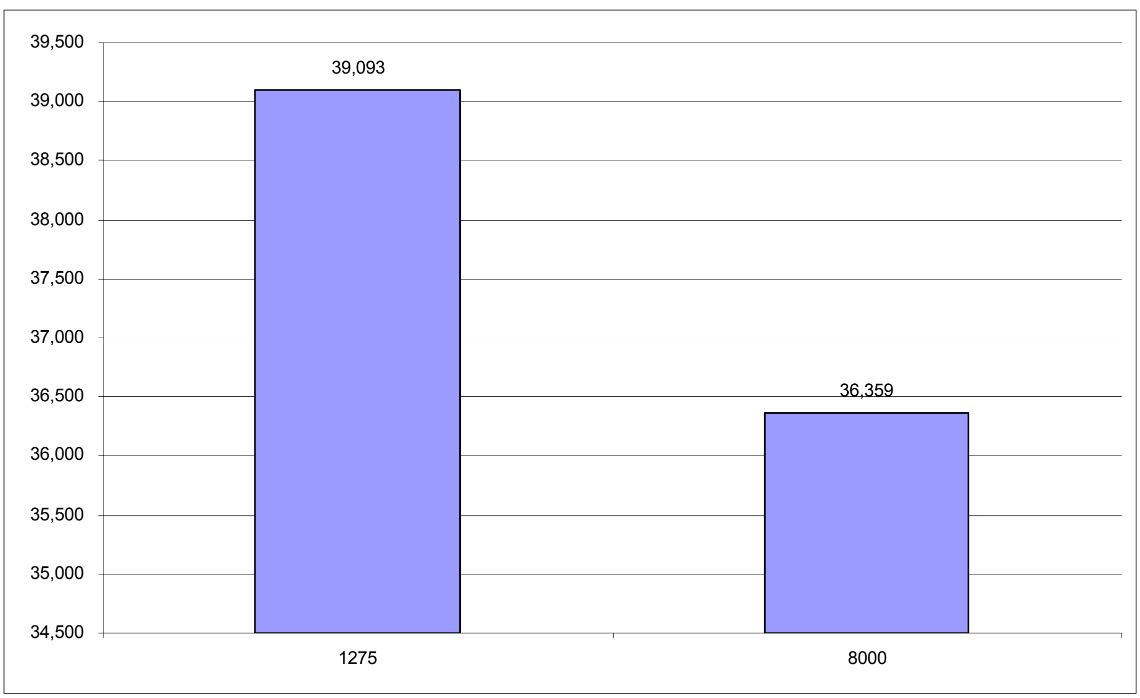


Figure 5.60: Reduction in NOx (short tons) as Wind Generation Increases for 2018

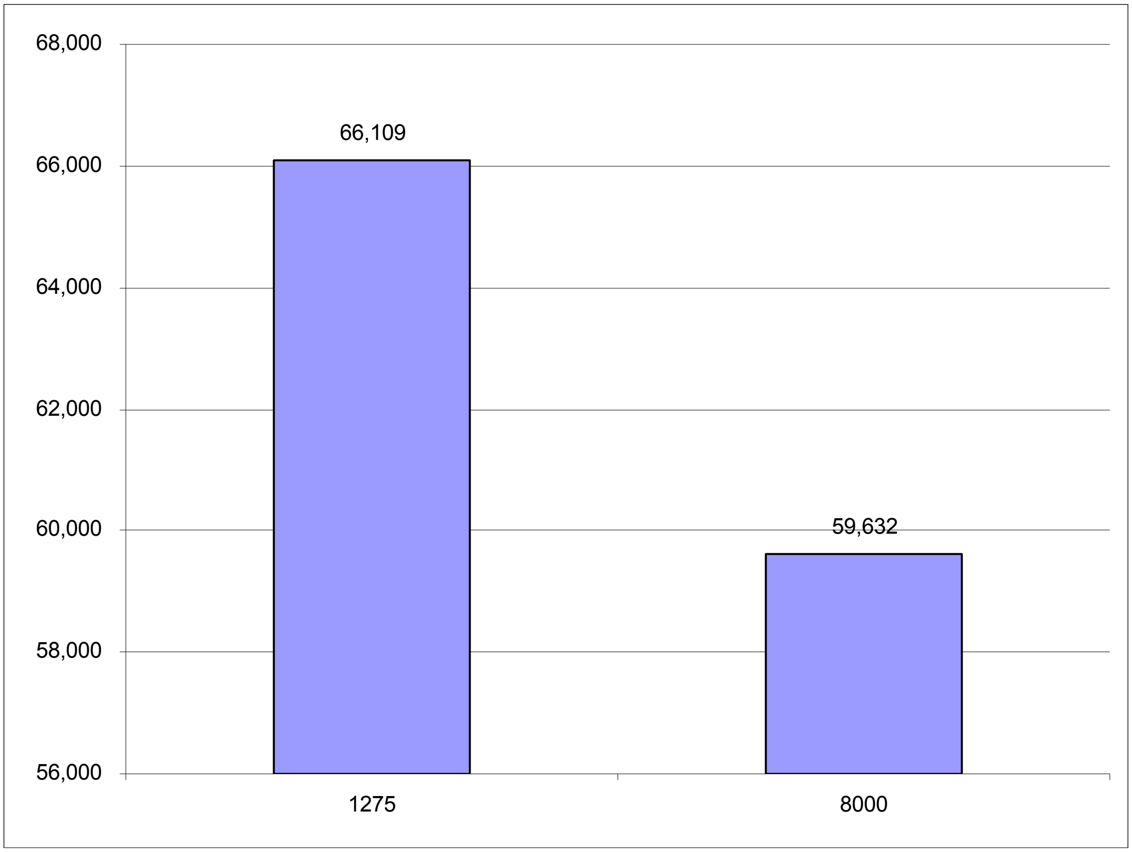


Figure 5.61: Reduction in SO_2 (short tons) as Wind Generation Increases for 2018

Summary of Findings for Emission Reductions:

For the 2018 load levels, the dispatch simulations with 8 GW of wind resources when compared to the base case which includes 1275 MW of installed wind resulted in a reduction of 4.9 million short tons of CO2 or an 8.5% reduction, a reduction of approximately 2,730 short tons of NOx or a 7% reduction and a reduction of approximately 6,475 short tons of SO_2 or a 9.7% reduction. Each GWh of fossil fired generation displaced results in an average reduction in CO_2 of approximately 315 tons. The total reduction of emissions would be higher except some of the wind generation is bottled by local transmission constraints.

5.6.6. Changes in Imports and Exports

The introduction of wind generation into the NYCA's resource mix with its much lower marginal costs of operation generally should tend to reduce imports and increase exports because of the relative price changes. The Figures 5.62 through 5.67 present the imports, exports and net for the 2013 and 2018 wind scenarios.

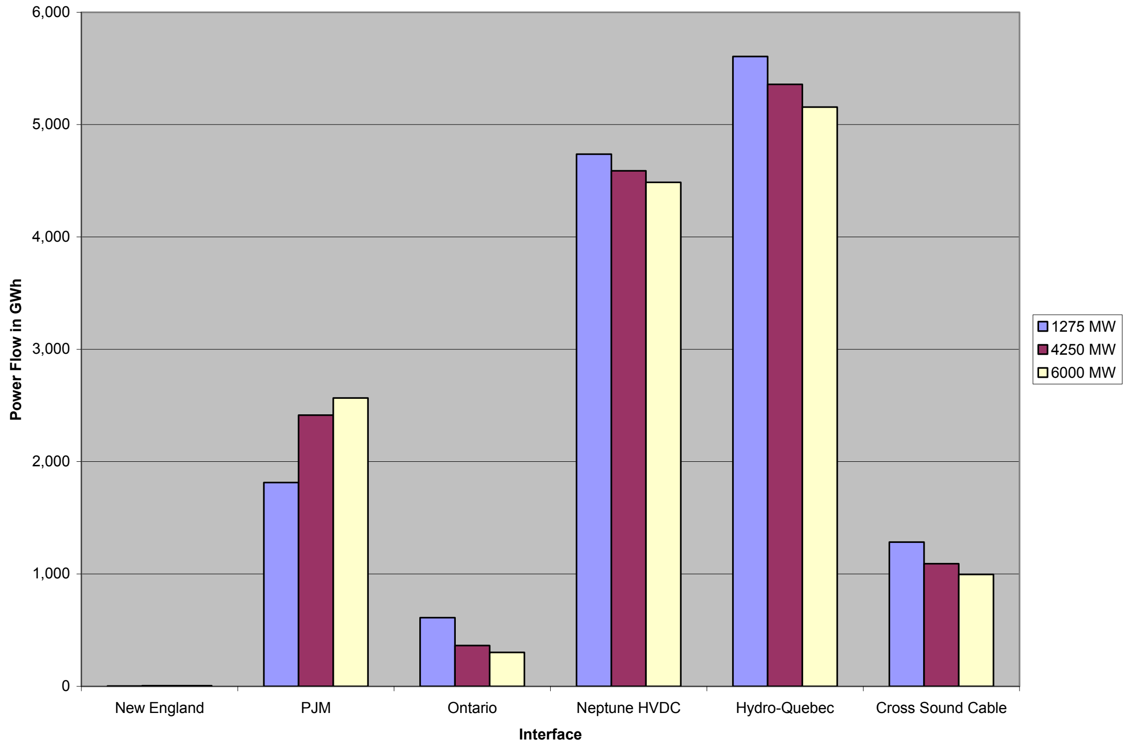


Figure 5.62: Imports for 2013 as Wind Plant Penetration Increases

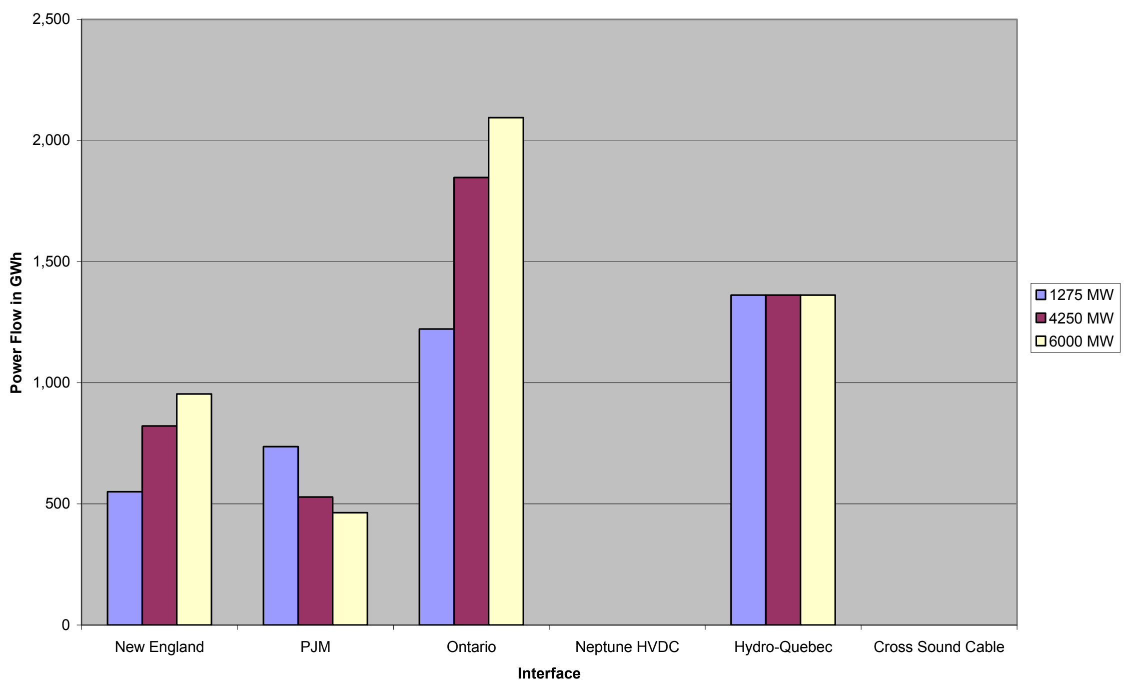


Figure 5.63: Exports for 2013 as Wind Plant Penetration Increases

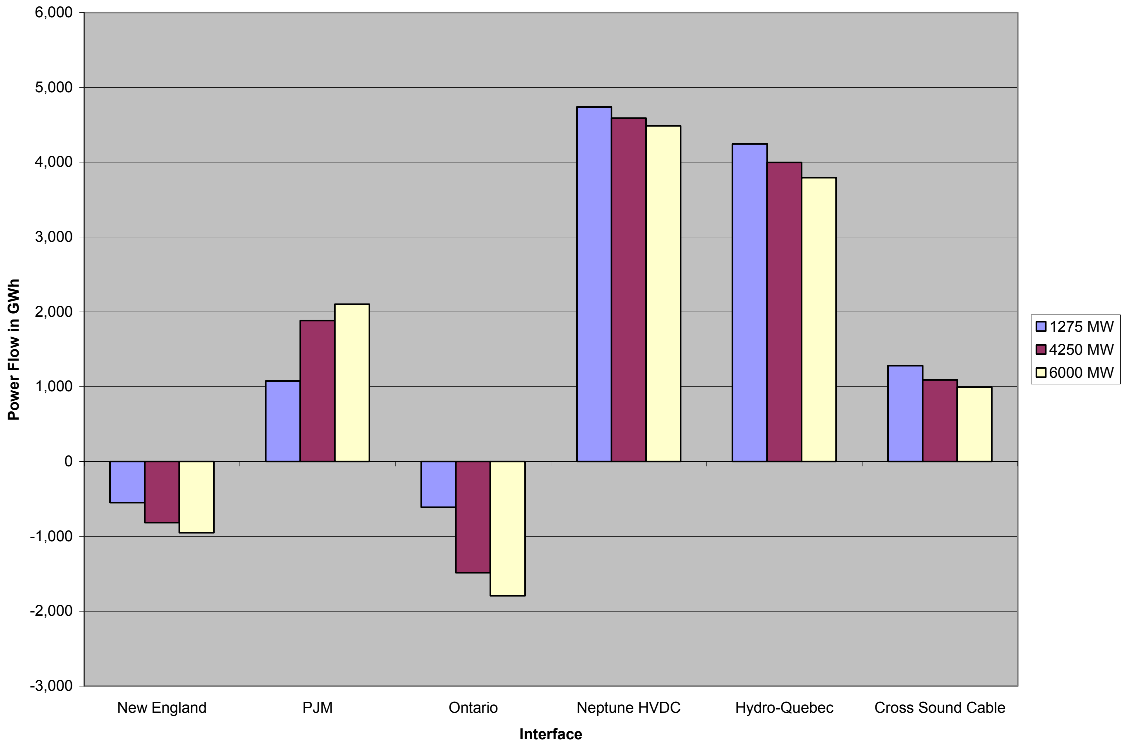


Figure 5.64: Net Import/Exports for 2013 as Wind Plant Penetration Increases

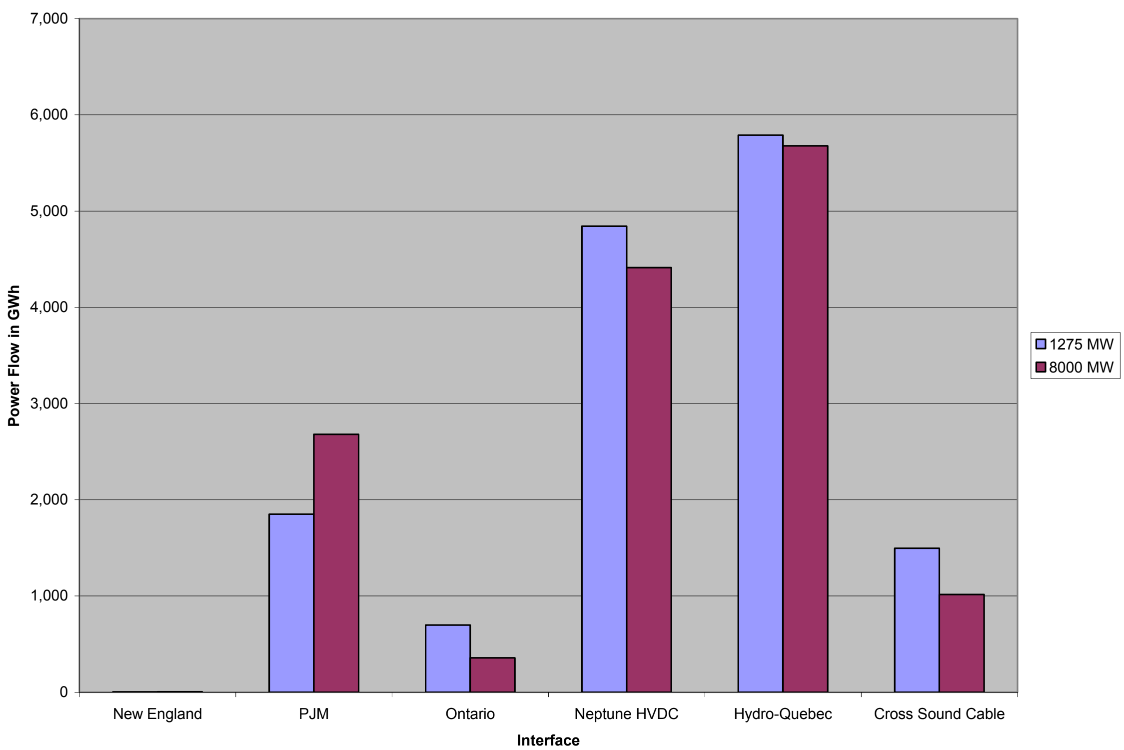


Figure 5.65: Import for 2018 as Wind Plant Penetration Increases

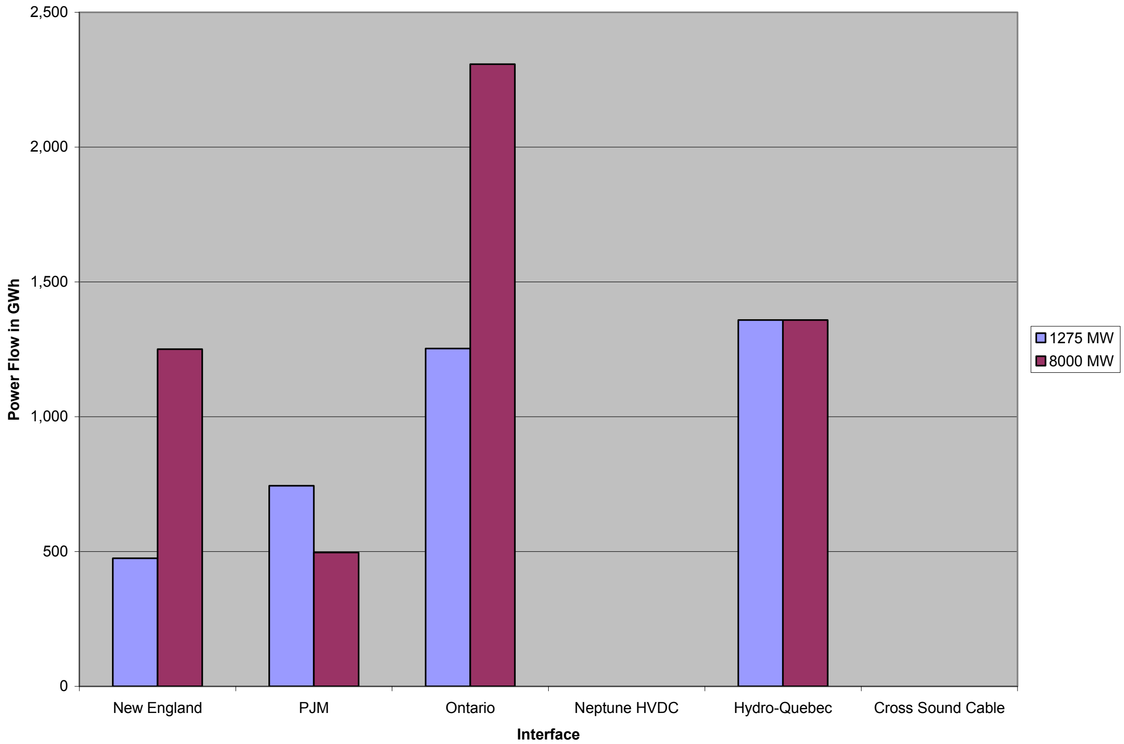


Figure 5.66: Export for 2018 as Wind Plant Penetration Increases

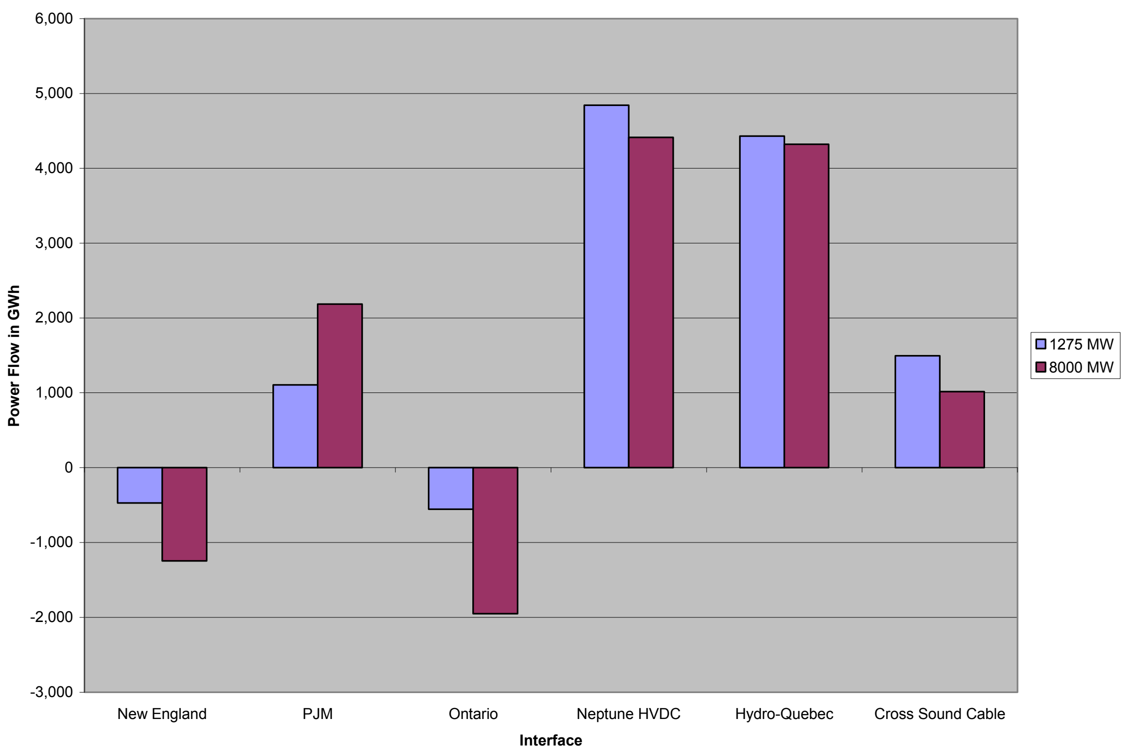


Figure 5.67: Net Import/Exports for 2018 as Wind Plant Penetration Increases

Summary of Findings for Imports/Exports:

For the 2018 simulations, the net imports for the NYISO show very little change as the level of installed wind increases while net exports increased. On an interface by interface basis, the results vary. Exports to New England and Ontario increase. Imports from Ontario decline while New England imports remain unchanged across all wind scenarios. The Neptune and CSC HVDC cables can only be used for imports and the imports decline as the installed wind increases. The Hydro Quebec interface was modeled as a schedule. The PJM interface flow changes run counter to an expectation of increasing exports and decreasing imports, with imports increasing and exports decreasing. This contradiction is the result of the wind resource addition in New York resulting in additional loop flow. Because of the physics of the power grid, the increased energy production in western New York will show up as an increase in loop flow. These increases in loop flow are evident in the increase in Lake Erie counterclockwise circulation. This increased circulation will show up as an export on the Ontario ties and an import on the PJM eastern ties. This increase in circulation was determined to have no significant impact on the results the study was focused on.

The analysis of production data in neighboring areas that are tied synchronously to New York shows slightly less electrical energy being produced in these areas while NY's total increases. This means as expected that on balance NY's imports decrease while its exports increase.

5.6.7. Changes in Congestion Payments and Uplift

It is expected that as more low cost generation is added in Upstate New York relative to the Downstate load centers congestion cost would increase. This outcome was indicated in the LBMP analysis. Also, since the fossil fuel generation that is committed will generate less energy and has to some extent been committed to respond to larger magnitude net-load ramping events, the expectation is that uplift could increase as installed wind generation increases. Figures 5.68 through 5.71 present the congestion payments for the 2013 and 2018 installed wind scenarios for superzones F-I and J-K which are the superzones most impacted by congestion.

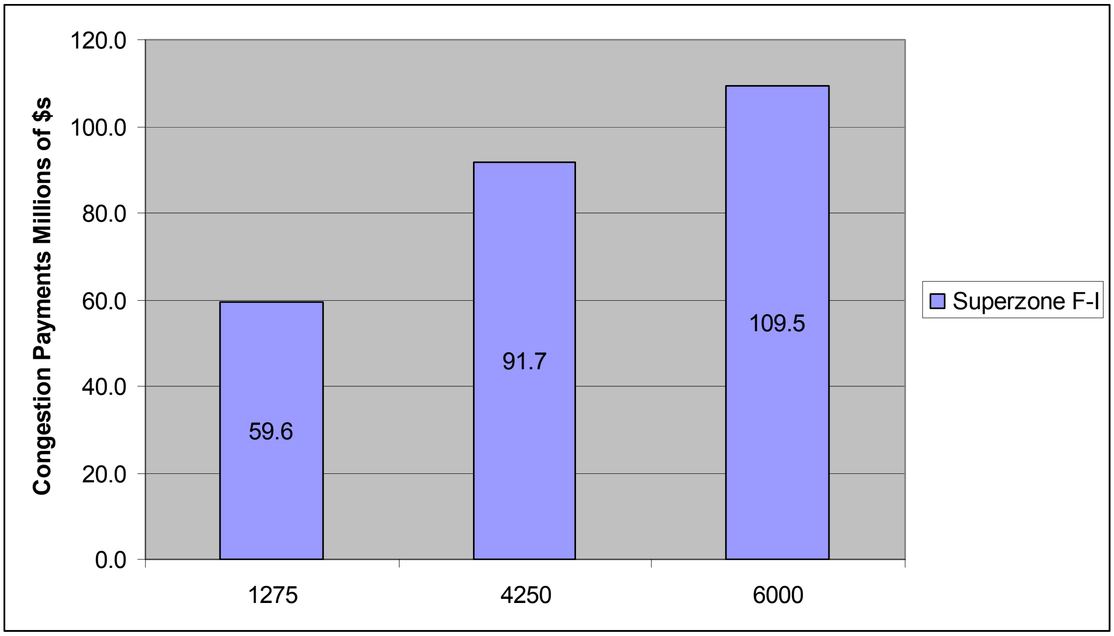


Figure 5.68: Congestion for 2013 by the Level of Installed Wind for Superzones F-I

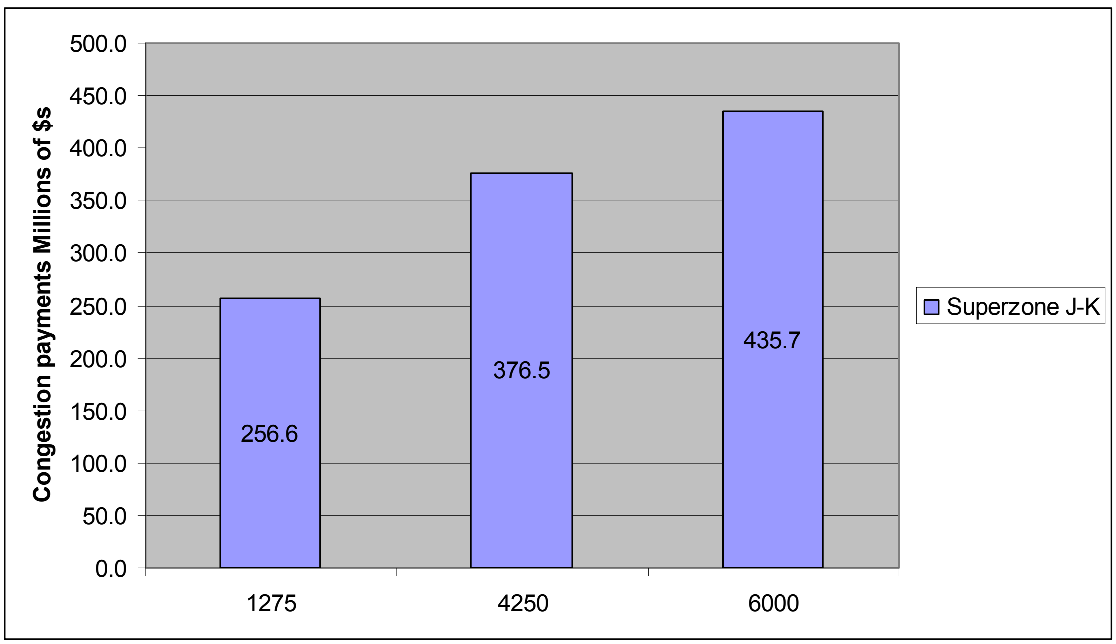


Figure 5.69: Congestion for 2013 by the Level of Installed Wind for Superzones J-K

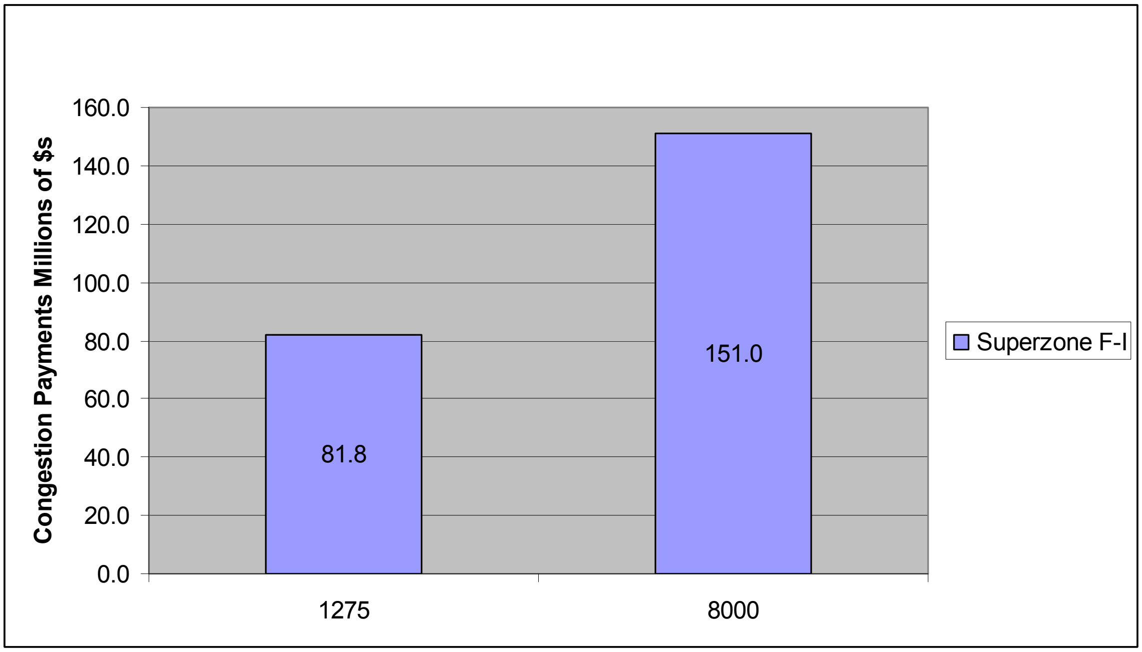


Figure 5.70: Congestion for 2018 by the Level of Installed Wind for Superzones F-I

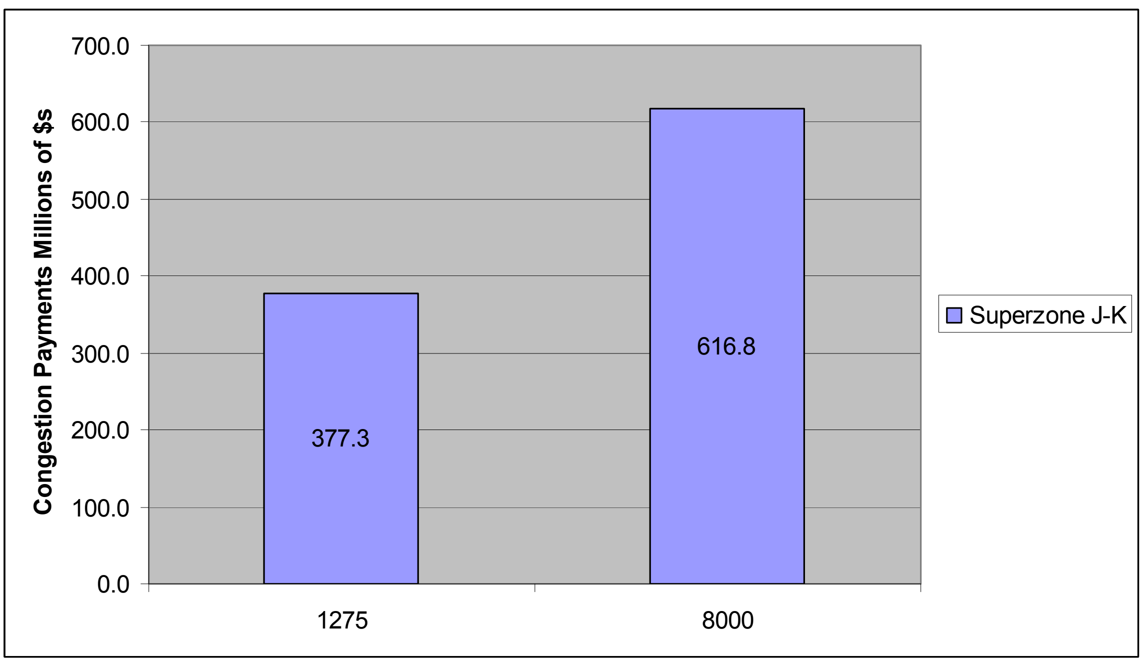


Figure 5.71: Congestion for 2018 by the Level of Installed Wind for Superzones J-K

Figures 5.72 through 5.73 present the uplift cost for 2013 and 2018 as the level of installed wind generation increases. The GridView model calculates the uplift cost on a daily basis. Uplift is the difference between a generators daily production costs and its LBMP payments.

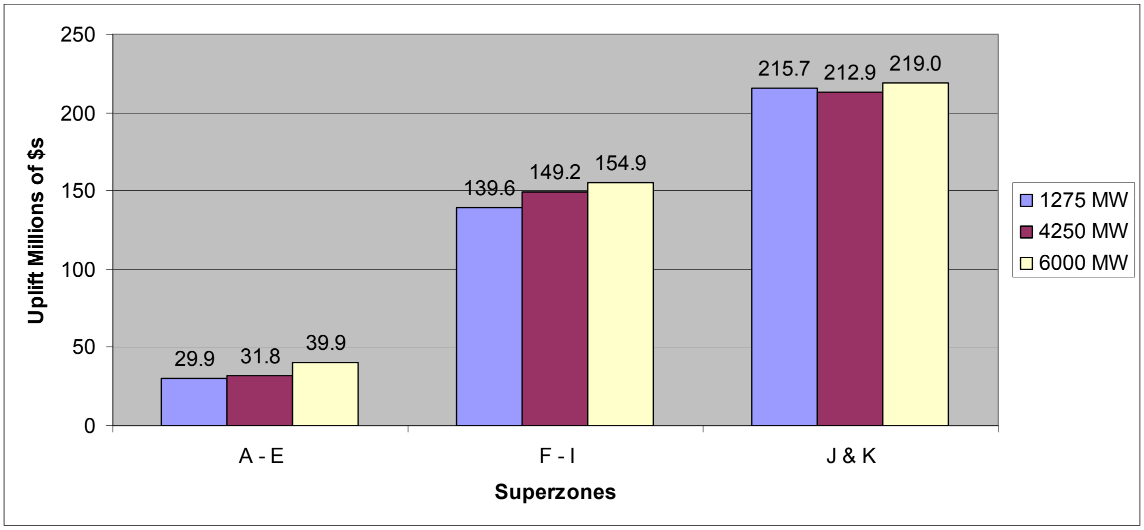


Figure 5.72: Uplift Costs for 2013 as the Level of Installed Wind Increases

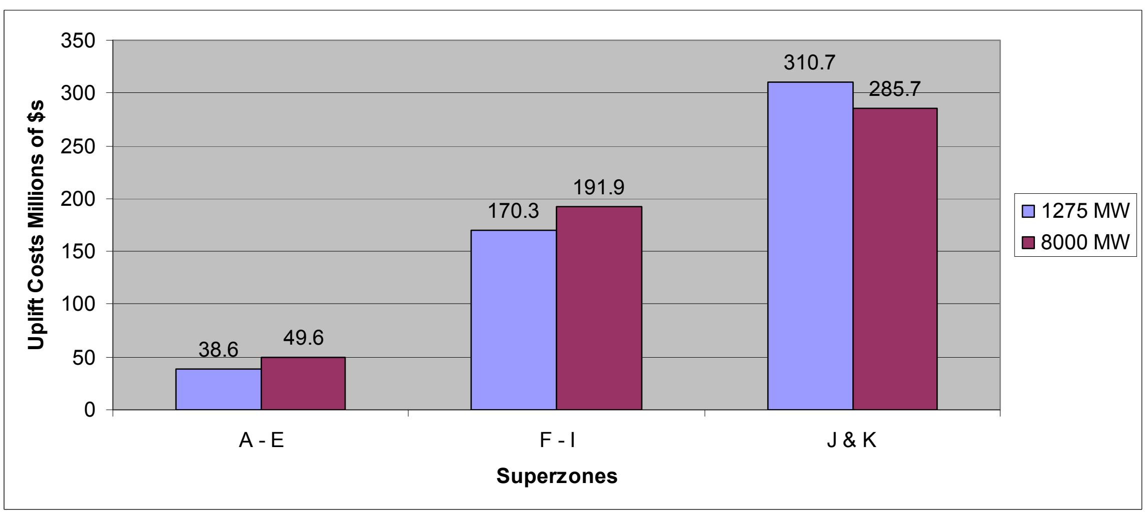


Figure 5.73: Uplift Costs for 2018 as the Level of Installed Wind Increases

Summary of Findings for Congestion Payments and Uplift:

As suggested by the LBMP trends, the congestion payments in superzones F-I and J-K increase as the level of installed wind generation is increased. The overall increase on a percentage basis as measured against the base case to 6,000 MW of wind in 2013 and 8,000 MW in 2018 ranges from a high of 85% for superzone F-I in 2013 to a low of 64% for superzone J-K in 2018. Also, the higher loads in 2018 tend to increase congestion payments while the addition of wind resources to superzone J-K in 2018 puts downward pressure on congestion payments.

Uplift costs tend to increase in superzones A-E and F-I as the level of installed wind generation increases which is expected. Superzone J-K uplift costs are, for the most part, flat as the level of installed wind increases for 2013 but actually decrease for 2018. This is the result of the offshore wind which has a capacity factor of almost 39% and tends to be more coincident with the daily load cycle and displaces high cost on-peak generation in the superzone while requiring less capacity for higher magnitude ramping events.

5.6.8. Changes in Thermal Plant Capacity Factors

The Tables 5-17 through 5-20 present the average annual capacity factors and how they change for those thermal unit and fuel types displaced by wind generation as the level of installed wind increases.

Table 5-17: Thermal Plant Capacity Factors for the NYISO

Installed Wind					
Fuel	**1275(2013)**	**4250**	**6000**	**1275(2018)**	**8000**
GT-NG	8.1%	7.1%	6.7%	11.3%	8.0%
ST-NG	27.1%	23.5%	22.0%	32.3%	22.5%
CC-NG	63.0%	57.6%	57.6%	65.1%	54.9%
OIL	9.8%	9.0%	8.8%	11.7%	9.4%
COAL	83.9%	83.0%	81.9%	83.9%	81.9%

Table 5-18: Thermal Plant Capacity Factors for Superzone A-E

Installed Wind					
Fuel	**1275(2013)**	**4250**	**6000**	**1275(2018)**	**8000**
GT-NG	4.9%	2.5%	1.8%	7.7%	2.5%
ST-NG	14.0%	10.4%	9.4%	17.2%	9.6%
CC-NG	49.8%	40.6%	35.0%	52.9%	34.9%
OIL	0.1%	0.1%	0.1%	0.2%	0.1%
COAL	83.3%	82.3%	81.0%	83.4%	81.0%

Table 5-19: Thermal Plant Capacity Factors for Superzone F-I

Installed Wind					
Fuel	**1275(2013)**	**4250**	**6000**	**1275(2018)**	**8000**
GT-NG	0.6%	0.4%	0.4%	1.2%	0.6%
ST-NG	13.3%	10.2%	9.0%	19.0%	9.9%
CC-NG	69.0%	64.5%	61.9%	71.1%	61.7%
OIL	0.2%	0.2%	0.1%	0.2%	0.2%
COAL	87.3%	87.3%	87.3%	87.3%	87.3%

Table 5-20: Thermal Plant Capacity Factors for Superzone J-K

Installed Wind					
Fuel	**1275(2013)**	**4250**	**6000**	**1275(2018)**	**8000**
GT-NG	8.5%	7.6%	7.2%	11.9%	8.7%
ST-NG	32.0%	28.2%	26.6%	37.0%	26.9%
CC-NG	64.9%	62.1%	60.8%	67.7%	60.7%
OIL	13.9%	12.8%	12.6%	16.7%	13.4%

Summary of Findings for Thermal Plant Capacity Factors:

Consistent with the findings for the fuel displacement analysis, the plants with the biggest decline in annual capacity factors are the natural gas fired plants. The capacity factors for the thermal plants are, as expected, impacted negatively by the addition of increasing wind plant penetration but positively by increasing load. The biggest reduction in annual capacity factors from 2013 base case level of 1,275 MW of wind when compared to the 8 GW scenarios occurs for the combined cycle plants in all superzones with a 30% decline in superzone A-E, 11% decline in superzone F-I and 6% decline superzone J-K.

5.7. Results for Task 7 - Identify Transmission System Upgrades:

5.7.1. Identification of Bottled Wind Resources

The results of the Task 6 simulations are analyzed to identify the transmission constraints – local and system – that result in potential wind energy production being limited (i.e., "bottled"). The active constraint(s) for each instance of energy bottling is reviewed and potential upgrade(s) are applied and the production cost simulation repeated. The iterative process continues until the wind energy bottling in each Zone is below 2% and/or NYCA-wide bottling is below 2%.

The production cost simulation results were evaluated to identify transmission congestion levels and the type(s) of resources that were being curtailed by transmission constraints. Transmission constraints were identified as "candidate for upgrade" if they resulted in curtailing wind energy production by more than 2% of the potential energy production on a zonal basis, or where an individual project's capacity factor was curtailed by more than 10%. Upgrades that could be considered in the initial evaluation were limited to incremental conductor or line-terminal upgrades (at the same operating voltage) or limited reconfiguration or existing physical plant.

The production cost simulations in Task 6 identified the same three general areas of congestion: southwestern portion of Central (Zone C), Willis (Zone D), and Watertown (Zone E). As the affected projects within these areas are generally independently constrained by different transmission elements and contingencies, the transmission upgrade scenarios could be tested in parallel. The Task 7 process is the step-by-step evaluation of each transmission corridor that constrains wind resources, and the evaluation of the upgrade: applying revised ratings or contingency definitions to the model, running successive simulations, and evaluating changes in wind resource bottling. This process is repeated until the wind resource bottling is less than 2% on a zonal basis, or all projects' capacity factors within the zone are curtailed by less than 10% (actual vs. potential capacity factor).

Evaluation of the transmission upgrades process was performed primarily on the 6,000 MW level case. The initial production cost simulation identified three zones with high levels of bottling (Central, North and Mohawk). Within each of these zones, specific constraints were related to individual or groups of wind projects to provide further guidance to the selection of transmission upgrades based on the extent of the bottling and number of effected projects.

The process tested a series of transmission upgrades and reinforcements that was able to minimize the bottling of wind resources in NYCA to less than 2%, and within all zones individually to less than 2% except in the Mohawk Zone. Within the Mohawk Zone the bottling was specific to the projects in the Watertown area.

Of all of the EHV (230kV and above) constraints that were tested in the production cost simulations, only three contributed to any significant level of wind resource bottling. Most of the wind resource bottling for the individual projects is caused by the local (115kV) transmission system between the projects and the EHV transmission system connection points.

At each step in the analysis, estimated costs for the upgrades are indicated. These are generic estimates based on the following assumptions:

Upgrade	Estimated Cost
Reconductor existing 115kV construction	$500,000-750,000/circuit mile
Rebuild existing 115kV	$750,000-1,500,000/circuit mile
Build new 115kV	$1,200,000-2,250,000/circuit mile
Build new 230kV	$2,250,000/circuit mile
Line terminal upgrade	$250,000-1,250,000/terminal
Protection upgrades	$250,000-500,000/terminal

The cost ranges reflect consideration of conductor size (ampacity or rating) and extent (and number) of tower reinforcement for existing lines, and greater structural strength for new or upgraded construction or complete rebuild of an existing line. Line terminal upgrades range from disconnect switches, station connections, or miscellaneous equipment (metering, CTs, PTs, wavetraps, etc.), to circuit breakers and station bus work. Line terminal upgrades also assume that the upgraded equipment will fit within the footprint of the existing equipment. Transmission owners have provided information to assist in identifying the limiting element(s) within each circuit and provide guidance as to the extent of structure rebuilding that would be necessary to accommodate any proposed reconductoring.

5.7.2. Overview of Transmission Upgrades

The analysis of the production cost simulations conclude that there are no major EHV reinforcements that are needed to accommodate the wind resource nameplate capacity levels of 6,000 MW or 8,000 MW. The existing NYCA EHV system congestion continues to follow historic patterns that follow the west-east/north-south flow patterns. As more wind resources are added to the NYCA the levels of congestion hours does not change significantly, but the relative value of the congestion increases as wind (as a price taker) displaces higher-cost generation resources.

Table 5-21: Summary of Base Case Wind Resource Bottling

Zone	1275		1275 (2018 load)		4250		6000		8000	
A	119	0.0%	119	0.0%	935	0.0%	1309	0.1%	1510	0.1%
B	6	0.1%	6	0.1%	86	0.0%	281	0.1%	418	0.1%
C	393	0.0%	393	0.0%	1110	6.7%	1591	6.3%	1860	6.2%
D	387	3.7%	387	3.7%	717	9.4%	1068	15.0%	1068	15.0%
E	368	0.0%	368	0.0%	1398	6.5%	1648	15.5%	1648	15.6%
F	0.1	0.0%	0.1	0.0%	0.1	0.0%	70	0.1%	70	0.2%
J									700	0.0%
K									700	0.0%
Total	1275	1.1%	1275	1.1%	4247	5.6%	5967	8.8%	7974	6.6%

There were only three identified EHV contingencies that cause significant wind resource bottling; all are double-circuit tower contingencies.

In the Elmira area of Zone C the 230kV double-circuit tower contingency (loss of Canandaigua – Hillside 230kV #68 and Hillside – Watercure 230kV # 69) generally limits wind resources west of Elmira area by overloading of local 115kV transmission circuits in the vicinity of the Hillside station. In the Binghamton area of Zone C the 345kV double-circuit tower contingency (loss of Oakdale – Fraser 345kV #32 and Oakdale – (Lapeer) Lafayette 345kV #36) generally limits wind resources west of the Binghamton area by overloading the 115kV transmission facilities east of Oakdale to the Delhi 115kV station.

In Zone D, the wind resources in the vicinity of Willis and east toward Plattsburgh are limited for the 230kV double-circuit tower contingency (loss of both Moses – Willis 230kV MW-1 and MW-2) by the 115kV transmission path between Willis and Colton.

5.7.3. Transmission Upgrades for 6,000 MW Buildout

The initial transmission upgrades considered were mitigation of these 3 tower contingencies. In each instance the extent of the double-circuit structures is 6 or 7 towers exiting the respective line terminals at Moses/St. Lawrence 230kV, Hillside 230kV and Oakdale 345kV, and the remaining distance of each circuit is on single-circuit structures. Mitigation of these contingencies would involve limited reconstruction of the 6- or 7-tower sections as individual single-circuit structures.

The 3 tower contingencies noted were removed from the Production Cost model, and the simulation was repeated to identify the next limiting constraints (contingencies and limiting facilities). As each project or group of projects and the corresponding constraints were evaluated in each subsequent production cost simulation, the selection of upgrades were considered based on the lowest cost for incremental transmission capacity benefit. If a limiting element has found a rating that is less than the design conductor rating, the first step would upgrade the facility to allow operation at the design conductor rating. If the facility is still limiting after that upgrade (conductor rating), reconductoring would be considered and the conductor size would be selected to minimize the need to rebuild all structures on the right-of-way end to end, if possible. The following details the process of evaluating necessary upgrades to accommodate 6,000 MW wind capacity and meet the objective of less than 2% state-wide and zonal bottling (when comparing the potential wind energy to the actual constrained energy production).

5.7.4. Step 1: Tower contingency mitigations

The three double-circuit tower contingencies are reconfigured to single circuit structures:

Moses-Willis 230kV MW1&2 reconfigure (7 towers) at Moses exit

Canandaigua-Hillside #68/Hillside-Watercure #69 230kV (7 towers) at Hillside exit

Oakdale-Fraser #32/Oakdale-Lafayette #36 345kV (6 towers) at Oakdale exit

The approximate cost for each of these upgrades is estimated at $2,000,000 to reconfigure a minimum of 3-4 towers at each existing location, assuming the double-circuit towers are each replaced with two (side-by-side) single-circuit structures on the existing alignment.

The double-circuit contingencies were removed from the model and the production cost simulation was run to identify the next limitations:

Zone C:

Montour Falls – Hillside 115kV for loss of Canandaigua – Hillside 230kV

Hillside – No. Waverly 115kV for loss of Watercure – Oakdale 345kV

Canandaigua – Avoca – Hillside 230kV pre-contingency loading

Zone D:

Plattsburgh 230/115kV transformers #1 and #4

Willis – Plattsburgh 230kV circuits. The loss of the Willis end section of either circuit results in the wind resources connected between Willis and Plattsburgh being radially connected through the transformer at the Plattsburgh end.

Zone E :

Delhi – Delhi Tap – Colliers 115kV for loss of Oakdale – Fraser 345kV

Black River – Taylorville 115kV for loss of tower Black River – Lighthouse Hill

Taylorville – Lowville 115kV for loss of tower Black River – Lighthouse Hill

The limiting facilities identified above in Zones D and E, and the Canandaigua – Hillside 230kV line are rated lower than the design conductor rating; the upgrade for these elements will identify components within the circuit (terminal equipment including disconnects, wave traps, etc.) that should be replaced to allow operation at design ratings. The 115kV facilities identified in Zone C are proposed to be reconductored based on the observed level of these constraints.

5.7.5. Step 2 Upgrades:

The following upgrades are based on the limitations observed after step 1 above:

Zone C:

The Montour – Hillside 115kV (2) circuits are reconductored (replace existing 336ACSR with 795ACSR) from Montour to the Ridge Road Taps; line terminal upgrades at Montour Falls (buswork and disconnect switches) and Hillside (buswork) are necessary to accommodate the higher rated conductor. The cost to rebuild the existing Montour Falls – Ridge Tap line sections (9.5 miles/each) and terminal equipment upgrades is approximately $20,900,000.

The Hillside – North Waverly 115kV is reconductored replacing the existing 2-4/0 ACSR with 795ACSR; and upgrade the buswork at North Waverly and line terminal equipment at Hillside. The cost to rebuild 17 miles of transmission line and terminal equipment is estimated at $17,500,000

The Canandaigua – Avoca – Hillside 230kV circuit is limited by CTs, wavetraps and bus work at the Hillside terminal; replacement of this equipment is estimated to be $1,000,000 to allow operation of the line up to its design conductor rating (1033 ACSR).

Zone D:

The line and transformer terminal connections at Plattsburgh 230/115kV are upgraded to allow operation of the 2-230/115kV transformers (#1 and #4) and the Plattsburgh end sections of the 230kV lines at design ratings. In reviewing these limitations, NYPA staff indicated that the replacement of the bus connections at Plattsburgh 115kV has been completed.

Zone E:

The line terminals for the Delhi – Delhi Tap – Colliers 115kV circuit are upgraded to allow operation of the line to design conductor rating (1033 ACAR). The limitation on this 3-terminal line is the distance protection relay settings; this upgrade is estimated to be $750,000 based on replacement of the existing relays at each terminal. This upgrade primarily benefits projects in Zone C.

The Black River – Taylorville #1, 2, & 8 115kV lines are upgraded to conductor rating (336ACSR) by upgrading station connections at several locations (est. total $600,000).

The corresponding ratings and circuit impedances in the simulation network model were updated to reflect the ratings and reconductoring of the limiting circuits and the simulation was repeated.

The next level of constraints was identified:

Zone C:

Bennett – Howard – Bath – Montour Falls 115kV pre-contingency loading

Bennett – Moraine Rd – Meyer 115kV for loss of Howard – Bath 115kV

Zone D:

Moses – Willis 230kV MW-1 for loss of Moses – Willis MW-2

Zone E:

Lighthouse Hill – Mallory 115kV for loss of tower Black River – Taylorville

Coffeen St. – E.Watertown, Coffeen St. – Black River, and Lyme Tap –Coffeen St. 115kV (all) pre-contingency loading

Most of the limiting elements identified in this step can be upgraded to operate to conductor rating by replacing terminal equipment. Based on the bottling levels observed, the Lighthouse Hill – Mallory (Clay) and Lyme Tap – Coffeen St. 115kV lines should be reconductored; however, the existing structures may not be capable of accommodating the necessary ampacity conductor.

5.7.6. Step 3 Upgrades:

The following upgrades are based on the limitations observed after the steps above:

Zone C:

The Bennett – Howard – Bath 115kV circuit can be upgraded to the 477ACSR conductor rating (780A) by replacing terminal equipment (breaker, CTs, disconnect switches) at Bath. (est. $1,000,000)

The Bath – Montour Falls 115kV circuit can be upgraded to the 602ACSR conductor rating (900A) by replacing terminal equipment (breaker, CTs, disconnect switches) at Bath and Montour Falls. (est. $2,000,000)

The Bennett – Moraine Rd – Meyer 115kV circuit can be upgraded to the 1033ACSR conductor rating (1250A) by replacing terminal equipment (breakers, CTs, disconnect switches and buswork) at Bennett and Meyer. (est. $2,000,000).

The (normally open) Andover – Palmiter Road 115kV is returned to in-service as recommended in the Canisteo Wind SRIS.

Zone D:

The Moses – Willis MW-1 and MW-2 230kV circuits are upgraded to design conductor rating (795ACSR). This will require replacing the bus, breaker and line connections at the St. Lawrence/FDR and Willis terminals (est. $2,000,000).

Zone E:

The Lighthouse Hill - Mallory 115kV circuit is rebuilt (replace 4/0 CU with 795ACSR); the estimated cost to rebuilt the 26.5 miles of line and upgrade the terminals is $41,855,000.

The Coffeen St. – Black River 115kV circuit is upgraded to design conductor rating (336ACSR) by replacing existing station connections at an estimated cost of $500,000.

The Lyme Tap – Coffeen St. 115kV circuit is rebuilt (replace 336ACSR with 795ACSR) and station connections upgraded for 1140A; est. cost for 6.9mi and line terminal upgrades is $9,588,000.

The Rockledge Tap – Lyme Tap 115kV is upgraded (connections at Lyme Tap) to operate at conductor rating (795ACSR) as identified in the Cape Vincent SRIS (est. $250,000).

As in the previous step (2), the corresponding ratings and circuit impedances in the simulation network model were updated to reflect the new ratings and reconductoring of the limiting circuits and the simulation was repeated.

The constraints identified in Step 3 are:

Zone C:

The Meyer – Eel Pot Rd – ECOGEN/GlobalNY-Flat St-Greenidge 115kV are limited pre-contingency

Zone D:

The Plattsburgh 230/115kV transformers limiting pre-contingency and contingency

Zone E:

The Taylorville-Boonville 115kV for loss of Lighthouse Hill – Mallory 115kV

5.7.7. Step 4 Upgrades:

The following upgrades are based on the limitations observed after the steps above:

Zone C:

The Meyer – Greenidge 115kV path is limiting between the wind projects' interconnection point to Greenidge and is only limiting when the 2 projects are in operation; if only one project is ultimately realized, no upgrade is necessary; the line sections from the project interconnection points to Greenidge are upgraded to conductor rating (336ACSR) by replacing existing 4/0CU buswork at Greenidge (est. $250,000).

Zone D:

The existing configuration of the Plattsburgh terminal does not have the high-sides of the 230/115kV transformers paralleled. To mitigate the contingency overloads of the transformers caused by power flowing from the 230kV to the 115kV and back to the 230kV through the other transformer the upgrade would require building out a full 230kV switchyard at an estimated cost of $14-16 million to mitigate the overloading of the transformers. As the wind resource bottling in the Zone is below the 2% target, this may not be cost-justified based on the remaining level of bottling.

Zone E:

The Taylorville-Boonville 115kV circuits are upgraded to operate at design conductor rating (336ACSR); this will involve replacement of station connections or buswork (est. $1,000,000).

The corresponding ratings in the simulation model were updated to reflect the upgrades and the simulation was repeated. The results indicate that the existing conductor is not adequate. In Zone E essentially all of the wind resource bottling is in the Watertown vicinity. The bottling is of sufficient magnitude that a conductor sized to accommodate the expected level of wind energy production is likely to involve a major rebuilding of the Watertown area transmission.

5.7.8. Step 5 Upgrades:

The following upgrades are based on the limitations observed after the steps above:

Zone C:

Eel Pot Road – ECOGEN/GlobalNY – Flat St – Greenidge 115kV is reconductored (replace 336ACSR with 477ACSR) for 28.9mi and station connections upgraded to 780A (est. $15,400,000).

Zone E:

Black River – Lighthouse Hill 115kV and Taylorville-Boonville 115kV circuits are rebuilt with 795ACSR for the entire length of both double-circuits (total 78.5 right-of-way miles). Including the intermediate and terminal upgrades (1140A) at 8 locations, the cost would be $119,868,000.

After these upgrades, the Watertown area wind resources remain significantly constrained by the Black River – Taylorville 115kV path for loss of tower Black River – Lighthouse Hill or Lighthouse Hill – Mallory 115kV. In Zone

C, the reconductoring of the ECOGEN – Greenidge lines relieved the last constraint. The wind resource bottling in Zones C and D is below the 2% target; in Zone E, only the projects in the Watertown vicinity are severely constrained.

5.7.9. Steps 6 - 7 Upgrades:

In Steps 6 and 7 additional reconductoring to identify a feasible transmission upgrade to accommodate the projects in the Watertown area is tested. These steps, when combined with the reconductoring already testing in preceding steps, effectively rebuilds the entire 115kV transmission system in the Watertown area. Review with the transmission owner (NationalGrid) indicates that the necessary conductor sizes cannot be accommodated by the existing structures and, including the Step 5 rebuilds above, will represent a complete rebuilding of over 200 circuit miles of 115kV transmission lines.

Step 6:

Rebuild Black River-N. Carthage #1, Black River-Taylorville #2, and N. Carthage-Taylorville #8 115kV (approx. 26.5mi. double-circuit tower); and replace 4/0 CU with 795ACSR, upgrade station connections to 1140A; estimated cost $38,693,000.

Step 7:

Rebuild Coffeen St – Black River #3 115kV replace 336ACSR with 795ACSR; 8.9mi., and station upgrades (1140A) estimated cost $9,160,000.

Indian River – Black River #9 provides the radial connection for the Dutch Gap project; upgrading this circuit to the conductor rating (795ACSR) involves buswork and station connections at Black River; est. cost $500,000. A limited amount bottling of the project output may still occur but may not justify reconductoring the circuit.

Additionally, the radial transmission "behind" Coffeen St. to Lyme Tap and the Rockledge Tap – Lyme Tap sections of the #4 115kV circuit severely constrain the output of the 3 projects that connect to that circuit. Reconductoring Coffeen St. – Black River #3 with 795 ACSR is not sufficient. Alternatives further tested rebuilding the existing with conductor sizes up to 1192ACSR, or 2-795ACSR and adding a 2nd parallel circuit (additional $10-20,000,000). The additional sub-scenarios (7a, 7b, and 7c) test larger conductor sizing to determine the extent of upgrades to accommodate the remaining bottling.

Reconductoring the Rockledge Tap – Lyme Tap – Coffeen St. (1192ACSR) and Coffeen St. – Black River #3 circuit (795ACSR) will reduce the overall resource bottling in Zone E to just under 2%, but at an additional cost of up to $24,545,000 (complete rebuild). The discussion with the Transmission Owner indicated that the reconductoring would require a complete rebuild. An alternative upgrade of the Rockledge – Coffeen St. would be the addition of a 2nd circuit (15 miles) in parallel with the existing circuit (this assumes the rebuilding the Coffeen St. – Lyme Tap section in Step 3). The cost of the 2nd (795ACSR) circuit is estimated $24,500,000.

Table 5-22: Summary of Wind Resource Bottling – 6,000 MW Base Case Upgrades

Zone	Wind Capacity	Base	Step 1	Step 2	Step 3	Step 4	Step 5	Step 6	Step 7
A	1309	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
B	281	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
C	1591	6.1%	4.5%	3.9%	1.2%	0.2%	0.0%	0.0%	0.0%
D	1068	15.0%	12.0%	2.5%	1.7%	1.7%	1.7%	1.7%	1.7%
E	1648	15.8%	15.1%	14.0%	11.1%	10.4%	11.0%	8.0%	3.3%
F	70	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%
Total	5967	8.8%	7.7%	5.4%	3.7%	3.2%	3.4%	2.5%	1.2%

5.7.10. Alternative Solution

The upgrades evaluated in Steps 5, 6 and 7 for the Watertown vicinity (Zone E) would require the complete rebuilding of over 200 circuit-miles of existing 115kV transmission lines, and there could still be a significant level of wind resources bottled in the Watertown vicinity. The extent of local 115kV transmission reconstruction may not be feasible.

An alternative solution to rebuilding the existing Watertown area 115kV network is to build a new 230kV transmission line between the existing Coffeen St. 115kV (Watertown) to Adirondack (Taylorville) 230kV stations (approximately 40 miles). The new 230kV line would be connected to the existing Coffeen St. 115kV station with a pair of 300MVA 230/115kV autotransformers.

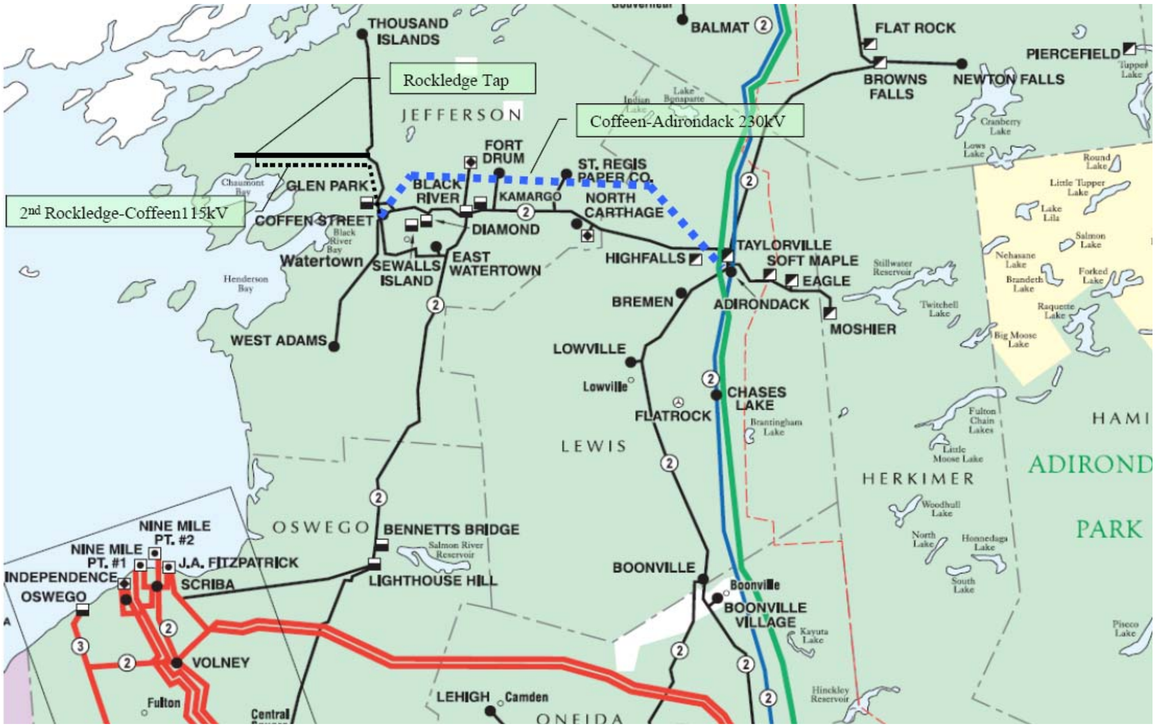


Figure 5.74: Transmission Map with 230kV Upgrade (dotted line)

The 230kV overbuild avoids the rebuilding of the Taylorville – Boonville, Black River – Taylorville, and Black River – Lighthouse Hill lines (approximately 185 circuit-miles or 104 ROW miles). Cost of the new 230kV station at Coffeen St., including the autotransformers and associated switchgear is estimated to be $35-38,000,000; additional 230kV line terminal (2 breakers and associated switchgear) at Adirondack is estimated to be $2-4,000,000. The cost of the 230kV line, including cost of new right-of-way, is approximately $2,250,000/mile, or $90,000,000 – or $133,600,000 complete. This compares favorably with the estimated $158,561,000 for the 115kV rebuild. The Rockledge – Lyme Tap – Coffeen St. 115kV upgrade is necessary in either case with the 2nd 115kV circuit to accommodate the output of the 3 projects that radially connect to Coffeen St., and the 4th project connecting at Black River.

All of the previously indicated upgrades in the other Zones (C and D) were unchanged. These upgrades and any of the indicated "line terminal upgrades" to conductor rating proposed for Zone E facilities in steps 5 and 6 are included in "System Upgrades." The relative resource bottling levels are presented for the 115kV-rebuild or 230kV-overbuild alternatives.

Table 5-23: Comparison of Watertown Alternatives – 6,000 MW Case

Zone	Wind Capacity	Base Case	System Upgrades	Watertown 115kV Alt.	Watertown 230kV Alt.
A	1309	0.1%	0.0%	0.0%	0.0%
B	281	0.1%	0.0%	0.0%	0.0%
C	1591	6.2%	0.4%	0.3%	0.5%
D	1068	11.3%	1.7%	1.7%	1.7%
E	1648	13.7%	8.2%	3.2%	3.6%
F	70	0.1%	0.1%	0.1%	0.1%
Total	**5967**	**7.6%**	**2.7%**	**1.3%**	**1.4%**

The data reported in Table 5-23 can also be expressed in terms of the bottled energy (MWh) or the unrealized wind energy production. This also provides additional guidance in the determination of the relative value of transmission reinforcements for specific project(s) or for a specific Zone's projects.

Table 5-24: Bottled Energy (MWh) Summary – 6,000 MW Case

6000 Base Case - Bottled Energy (MWh)					
Zone	**Wind Capacity**	**Base Case**	**System Upgrades**	**Watertown 115kV Alt.**	**Watertown 230kV Alt.**
A	1309	1,965	1,720	1,708	1,684
B	281	682	310	226	398
C	1591	286,368	16,380	16,093	21,438
D	1068	365,160	53,504	53,459	53,278
E	1648	647,623	390,202	153,768	171,055
F	70	217	247	244	295
Total	**5967**	**1,302,014**	**462,363**	**225,498**	**248,149**

5.7.11. Transmission Upgrades for the 8,000 MW Buildout

The installed wind resource locations of the additional 2,000 MW consist of the 1,400 MW off-shore wind connecting to the NYC and LI Zones (J and K) while the remaining 600 MW is connecting at locations that were previously not constrained. Based on the locations of the additional capacity, the same sets of proposed transmission upgrades developed for the 6,000 MW case were applied to the 8,000 MW case. The resulting wind energy bottling levels and constraints were consistent with the 6,000 MW case results and did not indicate a need for any modification to the upgrade test sequence. The Watertown alternate reinforcement scenarios were also evaluated in the 8,000 MW case.

Table 5-25: Summary of Wind Resource Bottling – 8,000 MW Base Case Upgrades

Zone	**Wind Capacity**	**Base Case**	**System Upgrades**	**Watertown 115kV Alt.**	**Watertown 230kV Alt.**
A	1510	0.1%	0.1%	0.1%	0.1%
B	418	0.1%	0.0%	0.0%	0.0%
C	1860	6.2%	0.5%	0.5%	0.6%
D	1068	11.6%	1.7%	1.7%	1.7%
E	1648	13.5%	7.7%	**3.0%**	**2.9%**
F	70	0.2%	0.4%	0.4%	0.4%
J	700	0.0%	0.0%	0.0%	0.0%
K	700	0.0%	0.0%	0.0%	0.0%
Total	7974	5.8%	1.9%	1.0%	1.0%

5.7.12. Assessment of the Relative Cost/Value of the Benefits of the Transmission Upgrades Studied

During the review of study results, the NYISO was asked by stakeholders to provide a measure of the cost or value of the transmission upgrades relative to the benefits they provided in terms of the unbottled wind plant energy. The transmission analysis evaluated the effectiveness of each upgrade in terms of improving the wind energy production as either project (or Zone) capacity factors or total wind energy production by Zone. The incremental wind energy production (i.e., the difference in production before/after a transmission upgrade step) and the estimated cost for each step are summarized in the tables below.

Table 5-26: Cumulative Transmission Upgrade Costs ($1000)

	Zone C	Zone D	Zone E	NYCA
Step 1	$5,000.00	$2,000.00	$0.00	$7,000.00
Step 2	$45,150.00	$2,000.00	$2,050.00	$49,200.00
Step 3	$50,150.00	$4,000.00	$12,389.00	$66,539.00
Step 4	$50,400.00	$20,000.00	$13,389.00	$83,789.00
Step 5	$65,800.00	$20,000.00	$133,257.00	$219,057.00
Step 6	$65,800.00	$20,000.00	$172,450.00	$258,250.00
Step 7	$65,800.00	$20,000.00	$206,110.00	$291,910.00

The “unbottled-incremental” wind production is the increase in the total wind resource energy production that resulted from the transmission improvements associated with each upgrade step.

Table 5-27: Cumulative “Unbottled” Wind Plant Energy Production (MWH)

	Zone C MWHr	Zone D MWHr	Zone E MWHr	NYCA Total
Step 1	22,743	94,849	33,311	200,710
Step 2	100,646	402,878	89,446	893,574
Step 3	227,663	429,246	222,479	879,845
Step 4	220,893	429,008	259,250	959,857
Step 5	280,279	428,993	229,822	939,697
Step 6	280,158	429,068	393,115	1,082,937
Step 7	280,228	429,088	603,021	1,312,918

To provide a relative measure of the cost or value of the each upgrade, the NYISO developed a metric that relates the transmission upgrade costs to the increased MWH of wind energy production. This metric was developed using a simplified approach which assumes that the capital costs of the transmission upgrade are to be recovered over a period of 15 years and did not account for the time value of money or other carrying charges. The transmission cost/MWH of unbottled wind plant energy was calculated for each transmission upgrade step for each Zone. Table 5-28 presents the results of this calculation.

Table 5-28: 15 Year Annualized Transmission Upgrade Cost/MWH

	Zone C $/MWHr	Zone D $/MWHr	Zone E $/MWHr	NYCA Total
Step 1	$4.58	$1.41	$0.00	$2.33
Step 2	$29.91	$0.33	$1.53	$5.53
Step 3	$14.69	$0.62	$3.71	$5.04
Step 4	$12.40	$3.11	$3.44	$5.82
Step 5	$15.65	$3.11	$38.66	$15.54
Step 6	$15.66	$3.11	$30.81	$15.90
Step 7	$15.65	$3.11	$22.79	$14.82

These results can be presented graphically:

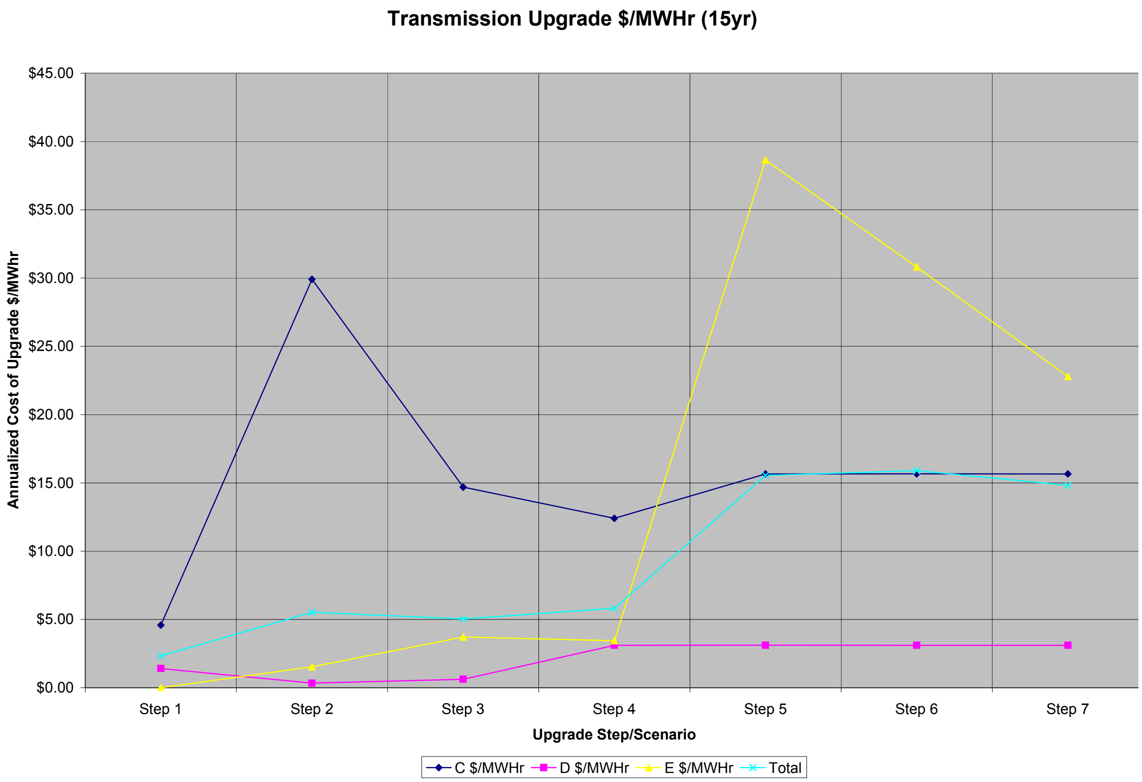


Figure 5-75: Summary Upgrade Cost/MWH

Although the results are presented by Zone, there is limited interaction among transmission upgrades in one Zone impacting (either beneficially or adversely) projects in an adjacent Zone. Some represented projects experience minimal curtailment over the entire range of the study, while certain projects may require substantial transmission upgrades to achieve expected capacity factors. As presented in Table 5-28 there are considerable differences in the relative costs/value between the upgrade steps both within and across zones. Again, this analysis has been conducted to provide some insight into the relative value or costs of the upgrades relative to the unbottled wind energy production.

5.7.13. Summary of Transmission Upgrades Analysis

Feasible sets of upgrades were developed and tested for the 6,000 MW and 8,000 MW wind resource build-out cases. Additional alternatives were suggested and tested to address the severe levels of resource bottling that occurs in the Watertown vicinity. The suggested transmission upgrades and alternatives require detailed physical review and economic evaluation before a final set of recommendations can be determined. Below is a summery of summary of the findings and upgrades identified:

There were three EHV transmission contingencies identified that should be mitigated.

There were five 230kV transmission lines where upgrading of line terminal facilities are necessary to allow the conductor to be operated at design ratings and will significantly reduce the level of bottled wind resources.

The remaining transmission upgrades identified can be associated with small groups of projects within a locality or Zone.

Some transmission upgrades are only necessary if all projects within a “congested group” are built.

With the exception of the Watertown vicinity of Zone E, most of the transmission upgrades involve local 115kV transmission circuits, and most of the ”resource unbottling” can be obtained through limited upgrading of the terminal facilities associated with those circuits.

A limited number of 115kV transmission circuits would need to be rebuilt with higher ampacity conductor to accommodate connection of specific project(s).

The most severe wind resource bottling occurs in the vicinity of Watertown (in all projected buildout cases); this is due, in part, to the extent of double-circuit tower construction and relatively light conductor in use.

The existing transmission infrastructure in the Watertown area makes reconductoring upgrades more likely to require a complete rebuilding as part of any effort to upgrade with higher-ampacity (larger size) conductor.

An alternative upgrade for the Watertown vicinity was evaluated consisting of a new 230kV transmission circuit from the existing Coffeen St. 115kV station (Watertown) to the Adirondack 230kV station, and a 2nd 115kV circuit from the Rockledge Tap station to Coffeen St.

The similarity of the bottling patterns in the 6,000 MW and 8,000 MW cases reflects the common locations of the capacity additions being studied. The most significant (1,400 MW) of the new wind resources added to expand from the 6,000 MW case to the 8,000 MW case is located in the NYC and LI zones, and 35% of the remaining resources added in Zones A through E connect directly to existing 345kV

There were no significant capacity additions in the vicinity of projects that were already constrained.

The 8,000 MW shows the same severe bottling in the Watertown vicinity as the 6,000 MW, and the transmission upgrades achieve similar results.

NYISO staff and the Transmission Owners are continuing to review the identified transmission constraints and the feasibility of the facility upgrades proposed.

6. Wind Study Conclusions

6.1. Overall Study Findings

The primary finding of the study is that wind generation can supply reliable clean energy at a very low cost of production to the New York power grid. This energy results in significant savings in overall system production costs, reductions in "greenhouse" gases such as CO_2 and other emissions such as NOx and SO_2 as well as results in an overall reduction in wholesale electricity prices. However, wind plants require a significant upfront capital investment. In addition, wind plants because of their variable nature and the uncertainty of wind plant output provide more of a challenge to power system operation than conventional power plants. This study determined that the NYISO's systems and procedures (which includes the security constrained economic dispatch and the practices that have been adopted to accommodate wind resources) will allow for the integration of up to 8 GW of installed wind plants without any adverse reliability impacts.

This conclusion is predicated on the assumption that a sufficient resource base is maintained to support the wind. The study determined that 8 GW of wind would reduce the need for conventional or dispatchable fossil fired generation on the order of 1.6 to 2 GW or an amount equivalent to 20-25% of the installed nameplate wind. This is the result of wind generations' much lower overall availability when compared to conventional generation. This means an amount of fossil generation equivalent to 75-80% of the nameplate installed wind needs to be available for those times when the wind isn't blowing or the wind plant output is at very low levels of output. Non-wind generation will be needed to respond to the higher magnitude ramps that will result because of winds variable nature.

As wind resources are added to the resource mix, their lower availability could result in an increase in the installed reserve margin and a decline in spot market prices. The impact of these changing conditions has not been analyzed in this report.

The fluctuating nature and the uncertainty associated with predicting wind plant output levels manifests itself as an increase in overall system variability as measured by the net load (load minus wind). In response to these increased operational challenges the NYISO has implemented changes to its operational practices such as being the first ISO to incorporate wind resources into security constrained economic dispatch (SCED) and to implement a centralized forecasting process for wind resources. The study concluded that at higher levels of installed wind generation the system will experience higher magnitude ramping events and will require additional regulation resources to respond to increased variability during the five minute dispatch cycle. The analysis determined that the average regulation requirement will need to increase by approximately 9% for every 1,000 MW increase in wind generation between the 4,250 MW and 8,000 MW level of installed wind.

Although the addition of wind to the resource mix resulted in significant reduction in production costs, the reduction would have been even greater if transmission constraints between upstate and downstate were eliminated. These transmission constraints prevent lower cost generation in upstate New York from displacing higher costs generation in southeast New York. This report did not analyze the potential financial impact of an increase in transfer capability from upstate into southeast New York.

Finally, the study determined that almost 9% of the potential upstate wind energy production will be "bottled" or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades to eliminate the transmission limitations. These upgrades were evaluated to determine how much of the wind energy that was undeliverable would be deliverable if the transmission limitations were removed.

Additional alternatives were suggested and evaluated to address the significant levels of resource bottling that occurs in the Watertown vicinity. The suggested transmission upgrades and alternatives require detailed physical review and economic evaluation before a final set of recommendations can be determined.

6.2. Summary of Study Results

The study has determined that as the level of installed wind plant MW increases, system variability as measured by the net-load increases for the system as whole. The increase exceeds 20% on an average annual basis from current levels for the 8 GW wind scenario and 2018 loads. The level of increase varies by season, month, and time-of-day. This will result in higher magnitude ramping events in all timeframes whether it is minute-to-minute or hour-to-hour that the dispatchable resources will need to respond to. Study results are reported for the New York system as a whole and for three superzones which are the western load zones A-E, the Hudson Valley load zones F-I, and the New York City and Long island load zones J-K. The study resulted in the following findings with respect to system reliability, system operations and dispatch, and transmission planning impacts of increasing the level of installed wind beyond the 3,300 MW originally studied.

6.2.1. Reliability Finding:

This study has determined that that the addition of up to 8 GW of wind generation to the New York power system will have no adverse reliability impact. The 8 GW of wind would supply in excess of 10% of the system's energy requirement. On a nameplate basis, 8 GW of wind exceeds 20% of the expected 2018 peak load. This finding is predicated on the analysis presented in this report and the following NYISO actions and expectations:

The NYISO has established a centralized wind forecasting system for scheduling of wind resources and requires wind plants to provide meteorological data to the NYISO for use in forecasting their output. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2008.*

The NYISO is the first grid operator to fully integrate wind resources with economic dispatch of electricity through implementation of its wind energy management initiative. If needed to maintain system security, the NYISO system operators can dispatch wind plants down to a lower output. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2009.*

The NYISO's wind plant interconnection process requires wind plants: 1) To participate fully in the NYISO's supervisory control and data acquisition processes; 2) To meet a low voltage ride through standard; and 3) conduct voltage testing to evaluate whether the interconnection of wind plants will have an adverse impact on the system voltage profile at the point of interconnection. In addition, the NYISO will continue to integrate best practice requirements into its interconnection processes.

The NYISO's development of new market rules assists in expanding the use of new energy storage systems that complement wind generation. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2009.*

The NYISO's installed resource base will have sufficient resources to support wind plant operations. As described in this report, the overall availability of wind resources is much less than other resources and their variability (changing output as wind speed changes) increases the magnitude of the ramps. For a system that meets its resource adequacy criteria (e.g., the 1 day in ten years), the additions of 1 MW of resources generally means that 1 MW of existing resources could be removed and still meet the resource adequacy criteria. However, the addition of 1 MW of wind would allow approximately 0.2 MW to 0.3 MW of existing resources to be removed in order to still meet the resource adequacy criteria. The balance of the conventional generation must remain in service to be available for those times when the wind plants are unavailable because of wind conditions and to support larger magnitude ramp events.

6.2.2. Operation and Dispatch Simulation Findings:

Analysis of the wind plant output and dispatch simulations resulted in the following findings for the expected impact of wind plant output on system operations and dispatch:

Finding One - Analysis of five minute load data coupled with a ten minute persistence for forecasting wind plant output (i.e., wind plant output was projected to maintain its current level for the next five minute economic dispatch cycle) concluded that increased system variability will result in a need for increased regulation resources. The need for regulation resources varies by time of day, day of the week and seasons of the year. The analysis determined that the average regulation requirement increases approximately 9% for every 1,000 MW increase between the 4,250 MW and 8,000 MW wind penetration level. The analysis for 8 GW of wind and 2018 loads (37,130 MW peak) resulted in the overall weighted average regulation requirement increasing by 116 MW. The maximum increase is 225 MW (a change from a 175 MW requirement up to 400 MW) for the June-August season hour beginning (HB) 1400. The highest requirement is 425 MW in the June-August season HB2000/HB2100.

Finding Two - The amount of dispatchable fossil generation committed to meet load decreases as the level of installed nameplate wind increases. However, a greater percentage of the dispatchable generation is committed to respond to changes in the net-load (load minus wind) than committed to meet the overall energy needs of the system. The magnitudes of ramp or load following events are reduced when wind is in phase with the load (i.e., moving in the same direction). However, for many hours such as the morning ramp or the evening load drop, wind is out of phase with the load (i.e., moving in the opposite direction). This results in ramp or net-load following events that are of higher magnitude than those that would result from changes in load alone. It is these ramp or load following events to which the dispatchable resources must respond.

Finding Three - Simulations with 8 GW of installed wind resulted in hourly net-load up and down ramps that exceeded by approximately 20% the ramps that resulted from load alone. It was also determined from the simulations the NYISO security constrained economic dispatch processes are sufficient to reliably respond to the increase in the magnitude of the net-load ramps. This finding is based on the expectation that sufficient resources will be available to support the variability of the wind generation. For example, the data base used for these simulations had installed reserve margins which exceeded 30%.

Finding Four - Simulations for 8 GW of wind generation concluded that no change in the amount of operating reserves[12] was needed to cover the largest instantaneous loss of source or contingency event. The system is designed to sustain the loss of 1,200 MW instantaneously with replacement within ten minutes where as a large loss of wind generation occurs over several minutes to hours. The analysis of the simulated data found for 8 GW of installed wind a maximum drop in wind output of 629 MW occurred in ten minutes, 962 MW in thirty minutes and 1,395 MW in an hour, respectively.

[12] Operating reserves is the amount of resources that are needed to be available for real-time operations to cover the instantaneous and unexpected loss of resources. The New York power system is operated to protect the system against the sudden loss of 1,200 MW of resources. Operating reserve as stated is an operational concept while the reserve margin discussed in section 6.2.3 is a planning concept. The reserve margin level is designed to maintain the risk of not having sufficient resource to meet the load to the acceptable level.

6.2.3. Resource Adequacy Findings:

To evaluate the impact of wind resources on NYISO installed reserve requirements, the study started with the New York State Reliability Council (NYSRC) Installed Reserve Margin[13] Study for the 2010-2011 Capability Year.[14] The NYSRC base case had an installed reserve margin of 17.9% to meet loss-of-load-expectation (LOLE) criteria of 0.1 days per year. That base case was updated to bring the installed wind resources to the full 8 GW of wind studied. The analysis of a system with this level of installed wind resulted in the following findings.

Finding One - The addition of 8 GW of wind resources to the NYSRC base case reduced the LOLE from the 0.1 days per year to approximately 0.02 days per year.

Finding Two – At criteria, the NYISO reserve margin would have to increase from its current level of 18% to almost 30% with 8 GW of nameplate wind as part of the resource mix. This was determined by using the methodology of removing capacity to bring the system to criteria and adding transfer capability in order for the wind plants to qualify for Capacity Rights Interconnection Service (CRIS). However, it should be noted that the NYISO's capacity market requires load serving entities to procure unforced capacity (UCAP) and capacity is derated to its UCAP value for purchase. As a result the total amount UCAP that needs to be purchased to meet reliability criteria remains essentially unchanged. The increase in reserve margin is because on capacity basis 1 MW of wind is equivalent to approximately 0.2 MW of conventional generation. Therefore, it requires a lot more installed wind to provide the same level of UCAP as a conventional generator. This results in an increase in the installed reserve margin which is computed on an installed nameplate basis.

Finding Three – The LOLE analysis resulted in an effective load carrying capability (ELCC) for the wind plants studied that exceeded 20%. The ELCC for this study exceeded the ELCC finding in the 2004 study by a factor of 2. Off-shore wind exhibits ELCC that is higher than on-shore wind because a greater percentage of the off-shore wind plants energy production occurs during peak hours. As an example, the GridView wind plant simulations based on 2006 wind data resulted in a 37.4% overall annual capacity factor (CF) for off-shore wind VS 34.3% for on-shore wind. However, the CF for off-shore wind plants during peak hours (the hours between 7am and 11 pm weekdays) was 39.7% for off-shore wind VS 32.5% for on-shore wind.

6.2.4. Production Cost Simulation Findings:

The production cost simulations conducted with ABB's GridView economic dispatch simulation model and the base case transmission system resulted in the following findings:

Finding One - As the amount of wind generation increases, the overall system production costs decrease. For the 2013 study year, the production costs drop from the base case total of almost $6 billion to a level of approximately $5.3 billion for the 6,000 MW wind scenario. This represents a drop of 11.1% in production costs. For the 2018 study year, the production costs drop from the base case total of almost $7.8 billion to a level of approximately $6.5 billion for the 8,000 MW wind scenario. This represents a drop of 16.6% in production costs. The change in production costs reflect the commitment of resources that are needed to support the higher magnitude ramping events but do not reflect the costs of the additional regulating resources.

[13] Reserve margin is the amount of additional capacity above the peak load that is needed so that the risk of not having sufficient capacity available to meet the load meets the minimum reliability criteria. It is expressed as a percentage and is calculated by dividing the required level of resources by the expected peak load. Resource can be unavailable because of equipment failure, maintenance outage, lack of fuel, etc. The higher the unavailability of the overall resource mix the higher the installed reserve margin will be.
[14] http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

Finding Two - Based on the economic assumptions used in the CARIS study, locational-based marginal prices (LBMP) or spot Energy prices decline as significant amounts of essentially zero production cost generation that participates in the market by using price taker bids is added to the resource mix. For the 2018 simulations, the NYISO system average LBMP prices are 9.1% lower for the 8 GW wind scenario when compared to the base case or 1,275 MW of installed wind.

Finding Three - The LBMP price impacts are greatest in the superzones where the wind generation is located and tends to increase the price spread between upstate where wind is primarily located in the study and downstate, which implies an increase in transmission congestion.

Finding Four - The primary fuel displaced by increasing penetration of wind generation is natural gas. For the simulations with 8 GW of wind with 2018 loads, the total amount of fossil-fired generation displaced was approximately 15,500 GWh. Gas-fired generation accounted for approximately 13,000 GWh or approximately 84% of the total. Oil and coal accounted for approximately 2,050 GWh and 465.1 GWh respectively, or approximately 13% and 3% of the total fossil generation displaced.

Finding Five - As suggested by the LBMP trends, the congestion payments in superzones F-I and J-K increase as the level of installed wind generation is increased. The overall increase in congestion payments on a percentage basis as measured against the base case compared to 6,000 MW of wind in 2013 and 8,000 MW in 2018 ranges from a high of 85% for superzone F-I in 2013 to a low of 64% for superzone J-K in 2018.

Finding Six - The addition of wind resources to superzone J-K in the 2018 case puts downward pressure on LBMPs in those zones, and therefore lowers congestion payments.

Finding Seven - Uplift costs tend to increase in superzones A-E and F-I as the level of installed wind generation increases. Superzone J-K uplift costs are for the most part flat as the level of installed wind increases for 2013 but actually decrease for 2018. This is the result of the offshore wind which has a capacity factor of almost 39% and tends to be more coincident with the daily load cycle and displaces high cost on peak generation in the superzone while requiring less capacity for higher magnitude ramping events. Off shore wind also provides greater capacity benefits.

Finding Eight - The capacity factors for the thermal plants are, as expected, decreased by the addition of wind plants, but this is partially offset by increasing load. The biggest reduction in annual capacity factors from the 2013 base case level of 1,275 MW of wind when compared to the 8 GW scenarios occurs for the combined cycle plants in all superzones with a 30% decline in superzone A-E, 11% decline in superzone F-I and 6% decline superzone J-K. As would be expected the biggest impact is in the superzone with the highest level of installed wind with transmission capacity limitations between the superzones contributing to the reduction.

6.2.5. Environmental Findings:

For the 2018 load levels, the dispatch simulations with 8 GW of wind resources resulted in the following emissions reductions in comparison to the base case with1, 275 MW of installed wind:

Finding One – A CO_2 emission reduction of approximately 4.9 million short tons or a reduction of 8.5%.

Finding Two - Each GWh of displaced fossil-fired generation which primarily consisted of natural gas resulted in an average reduction in CO_2 of approximately 315 tons.

Finding Three - A NOx emission reduction of approximately 2,730 short tons or a reduction of 7%.

Finding Four – A SO_2 emissions reduction of 6,475 short tons or a reduction of 9.7%.

6.2.6. Transmission Planning Findings:

Extensive power flow analysis in conjunction with dispatch simulations was conducted to determine the impact of transmission system limitations on the energy deliverability of the wind plant output. The analysis resulted in the following findings:

Finding One - Given the existing transmission system capability, the 6 GW scenario determined that 8.8% of the energy production of the wind plants in three areas in upstate New York would be "bottled" or not deliverable.

Finding Two – The primary location of the transmission constraints was in the local transmission facilities or 115 kV voltage level.

Finding Three - The off-shore wind energy as modeled was fully deliverable and feeds directly into the superzone J-K load pockets.

Finding Four - The study evaluated 500 miles of transmission lines and 40 substations to determine potential upgrades that would result in the "unbottling" of the wind energy.

Finding Five - If all the upgrades studied were implemented, the amount of wind energy not deliverable would be reduced to less than 2% for the upstate wind.

Finding Six - Depending on the scope of upgrades required, such as reconductoring of transmission lines compared to rebuilding or upgrading terminal equipment, the cost of the upgrades could range from $75 million to $325 million. However, it should be noted that many of the transmission facilities studied are approaching the end of their expected useful lives.

Finding Seven - Transient Stability Analysis was conducted to evaluate the impact of high wind penetration on NYCA system stability performance. The primary interface tested was the Central East. The Central East stability performance has been shown historically to be key factor in the dynamic performance of the NYISO power grid. The NYISO power grid (and the Interconnection) system demonstrated a stable and well damped response (angles and voltages) for all the contingencies tested on high wind generation on-peak and off-peak cases. There is no indication of units tripping due to over/under voltage or over/under frequency.

Finding Eight - Wind plants that are in the NYISO interconnection 2008 class year study and beyond may require system deliverability upgrades to qualify for Capacity Resource Integration Service (CRIS). This totals approximately 4,600 MW of new nameplate wind plants that were included in the study. In order to qualify for capacity payments, the wind plants in class year 2009/2010 and beyond in upstate New York would need to increase transmission transfer capability between upstate New York and southeast New York (a.k.a., the UPNY-SENY interface). This transmission interface primarily consists of 345 kV transmission lines in the Mid-Hudson valley region running through Greene County, New York south of Albany to Dutchess County, New York or between Zones E and F and Zone G. The study determined that approximately 460 MW of interface transfer capability needs to be added to this interface for the wind plants that did not qualify for capacity payments to be eligible for them. This does not impact the deliverability of the wind plants energy but only their ability to qualify for capacity payments or CRIS.

Appendix A: Summary Wind Plant Performance Metrics For 2009

Month	Nameplate Total MW (avg. daily)	Average Capacity Factor	Peak Hour Coincidence Factor (CF) 1,2	Max 1 HR Output MW	Number Of Days with Hrs < 0
January	978.8	29.7%	9.1%	838.4	2
February	1140.3	35.7%	28.4%	997.2	1
March	1273.9	24.0%	28.9%	1002.2	5
April	1273.9	32.2%	38.7%	1058.5	0
May	1273.9	23.1%	8.1%	1070.5	2
June	1273.9	10.2%	25.8%	625.8	7
July	1273.9	15.9%	12.5%	769.7	4
August	1273.9	13.2%	16.5%	716.4	5
September	1273.9	14.7%	9.5%	1001.2	7
October	1273.9	21.7%	8.9%	1171.7	2
November	1273.9	21.9%	10.6%	1144.4	2
December	1273.9	31.5%	10.7%	1114.1	3

1) CF is the ratio of wind plant output at the system peak hour to nameplate

2) Summer Capacity value for wind plant is defined as the capacity factor between the hours of 1400 and 1800 for the summer months of June, July and August. The summer 2007 value was 22.9%, the summer 2008 value was 16.7% and summer 2009 was 14.1%. Winter Capacity value for wind plant is defined as the capacity factor between the hours of 1600 and 2000 for the winter months of Dec., Jan. and Feb. The winter value for 07-08 was 30.4%. The winter 08 - 09 value was 24.2% and the 09-10 value was 26.4%.

Appendix B: Summary of Other Regions' Experiences with Wind Generation

Appendix B-1: Summary of Key Lessons from European Wind Integration Experience

Europe shows that high/very high wind penetration levels are possible, but those high penetration levels are driven by energy policy (subsidies) and not economics for the most part. This also applies to power system integration issues.

Wind power can be successfully included into markets (Spain/UK).

European regulators and Transmission System Operators (TSOs) have developed a willingness to learn and question existing rules as well as to adjust rules and regulations. In addition, most European countries have shown a flexibility to adjust their energy policy, rules and regulations depending on the technical and economical development in order to create a low-risk environment for renewable energy projects, without allowing windfall profits as it is very difficult to get all relevant regulatory details right at the first attempt. This flexibility for change has been based on a continuous dialogue between policy makers, regulators, network companies and the renewable energy lobby.

Both load and generation benefit from the statistics of large numbers as they are aggregated over larger geographical areas. Larger balancing areas make wind plant aggregation possible. The forecasting accuracy improves as the geographic scope of the forecast increases; due to the decrease in correlation of wind plant output with distance, the variability of the output decreases as more plants are aggregated. On a shorter-term time scale, this translates into a reduction in reserve requirements; on a longer-term time scale, it produces some smoothing effects on the capacity value. Larger balancing areas also give access to more balancing units.

The development of grid codes played an important role for Europe to ensure a reliable power system operation. Improvements in wind-plant operating characteristics has enhanced reliable operation of the system through the ability to provide voltage control at a weak point in the system, the ability to provide an inertial response in a stability-constrained system, the ability to participate in providing ancillary services, and the ability to ride through faults (voltage and frequency deviations) without disconnection. Remaining issues in Europe are old wind turbines which do not meet the requirements of the grid codes and validation of turbines/simulation models that fulfill the grid codes.

Integrating wind generation information in system operation both real-time and with updated forecasts up to day-ahead will help manage the variability and forecast errors of wind power. Shortening the gate closure time in market operation practices will help integration but may require improvements in the operating tools. Well-functioning hour-ahead and day-ahead markets can help to more cost-effectively provide balancing energy required by the variable-output wind plants.

Specific wind farm control centers (Spain) combined with power system state estimators provide a powerful tool for large-scale wind integration as wind farms can be remotely adjusted (on/off/part-load/PF control), taking into account real-time conditions in the power system.

Frequency control with wind turbines has been tested in Denmark and the United Kingdom, wind turbines/farms are expected to actively participate in the frequency control task in the future.

Black-start in power systems with high wind penetration level could be problematic. Denmark is developing a new, cell-based power system architecture which will incorporate wind power in the black-start procedure.

Transmission helps to achieve benefits of aggregating large-scale wind power development and provides improved system balancing services. This is achieved by making better use of physically available transmission capacity and upgrading and expanding transmission systems. High wind penetrations may also require improvements in grid internal transmission capacity.

Appendix B-2: Summary of the CAL-ISO Study

The planned $1.8 billion of transmission upgrades for the Tehachapi area are sufficient to support up to 4,200 MW of new renewable resources.

New wind generation resources should be Type 3 or Type 4 units as the installation of more Type 1 units in Tehachapi has a negative impact on the reliability of the system.

All new generating facilities, including new wind generation facilities, must meet the California ISO Interconnection Standards, provide 4-second operating data and be prepared to act on dispatch notices from the California ISO Operations.

Integrating 20% renewables in the current generation mix is achievable; however, several market integration and operational changes are required.

Transient stability studies indicated that the new Tehachapi wind generation with Type 3 or Type 4 units, meets WECC LVRT as well as the WECC transient stability standard.

Some of the existing Tehachapi wind generation (Type 1 Units) trips off-line for three phase 500 kV faults in the local area under the full wind scenario.

Post-transient governor power flow analysis results indicate that the WECC standards are met.

A state-of-the-art wind forecasting service is necessary in the Day-Ahead time frame to minimize errors in the unit commitment process. The accuracy of Day-Ahead load and wind generation forecasts will affect the market clearing prices and unit commitment costs.

Approximately 800 MW/hr of generating capacity and ramping capability will be required to meet multi-hour ramps during the morning load increase coupled with declining wind generation. Operations will need to be able to quickly ramp down dispatchable resources during the evening load drop-off and accommodate increases in wind generation.

The amount of regulation required will significantly increase with large amounts of new wind generation.

The size of the supplemental energy stack must significantly increase to meet intra-hour load following needs.

The California ISO must have the ability to curtail wind generation during over-generation conditions.

Short start units must be available to accommodate Hour-Ahead forecast errors and intra-hour wind variations. The quantity of short start units that will be needed requires additional analysis and modeling.

Comments of the California ISO President & CEO Yakout Mansour:

“The good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20% RPS, provided that existing generation remains available to provide back-up generation and essential reliability services. The cautionary news is the “provided” part of our conclusion. Regulatory actions under active consideration threaten the economic viability of much of this essential generation. Moreover, current regulatory policies assigning high on-peak availability factors to intermittent generation will eliminate the theoretical — but not the real — need for the essential generation currently provided by existing power plants, and regulators may be unwilling to support sufficient forward procurement of generation. Furthermore, the model used for this study is based on the technical specifications and capabilities of the generation fleet, but does not reflect contractual or other regulatory constraints that are not known to the California ISO.”

Appendix B-3: Summary of the ERCOT Study

Uncertainty and variability are an inherent part of power system operations; power system infrastructure and operating practices have developed around the requirement to accommodate variability and uncertainty. Addition of wind generation capacity increases both, but does not greatly change their nature. The tools of operation used to address these attributes for load alone are expandable to address the net load resulting from wind generation partially offsetting connected system load.

An overall observation in this study is that through 5,000 MW of wind generation capacity, approximately the level of wind capacity presently in ERCOT, wind generation has limited impact on the system. Its variability barely rises above the inherent variability caused by system loads. At 10,000 MW wind generation capacity, the impacts become more noticeable. By 15,000 MW, the operational issues posed by wind generation will become a significant focus in ERCOT system operations. However, the impacts can be addressed by existing technology and operational attention, without requiring any radical alteration of operations.

While ERCOT's present regulation procurement methodology is adequate in terms of procuring sufficient regulation service, there are improvements that can be made which are expected to reduce the amount of procurement while maintaining sufficiency. Most notable is the inclusion of wind generation forecast information. Also, adjustments are advisable to accommodate year-to-year wind generation capacity growth.

Proper use of wind generation forecasting is of critical importance to reliable and efficient operation of the system. In addition to making efficient unit commitment decisions, wind forecasts allow ancillary services procurements to be adapted to actual conditions. The risks of extreme weather events are generally very predictable, and appropriate operating decisions can be made to pre-emptively reduce their impact.

High penetration of wind generation reduces loading on thermal units while increasing the requirements for these units to provide ancillary services. Beyond ERCOT's present level of wind generation capacity, there will be infrequent periods when unit dispatch and commitment may need to be altered to provide ancillary services. Through the 15,000 MW wind generation capacity scenario investigated, these events become progressively more frequent.

Appendix B-4: Summary of the OPA Study

The average capacity value of the wind resource in Ontario during the summer (peak load) months is approximately 17%. The capacity value ranges from 38% to 42% during the winter months (November to February) and from 16% to 19% during the summer months (June to August). Since 87% of the hits (periods within 10% of the load peak) occur during the summer months, the overall yearly capacity value is expected to be heavily weighted toward the summer. The overall yearly capacity value is approximately 20% for all wind penetration scenarios. In other words, 10,000 MW of installed nameplate wind capacity is equivalent to approximately 2,000 MW of firm generation capacity. The capacity value is generally insensitive to the wind penetration level, mainly due to good wind geographic diversity and the fact that the various wind output levels are derived by scaling the same wind groups.

The results of the regulation analysis show that, in all scenarios, the incremental regulation needed to maintain current operational performance is small. With incremental regulation requirement defined as the increase in 3σ of the net-load with and without wind, the increase in regulation is only 11% with 10,000 MW of wind and 4% with 5,000 MW. This additional regulation could be handled within the current system operation framework.

Incremental load following requirements are more substantial due to increased variability in the 5-minute timeframe. The year 2009 load with 1,310 MW of wind scenario could be easily accommodated with the existing generators. The year 2020 load with 5,000 MW of wind scenario shows a 17% increase in load following requirements. It is likely that online generators could provide this incremental requirement. Beyond 5,000 MW of wind, the additional load following requirement may exceed the capability of existing generators. It is important that any future supply mix strategy recognize that wind generators will likely displace more flexible generation resources and the remaining balance-of-portfolio resources must be able to accommodate this additional variability.

The 10-minute operating reserve requirement is specifically tied to a single contingency, meaning that the reserve is meant to accommodate loss of a single unit, but not a simultaneous drop in generation and increase in load. Therefore, the 10-minute wind-alone variability was analyzed as a proxy for operating reserve requirements. The results show that with 5,000 MW of wind, the incremental operating reserve requirement is considered negligible but at higher wind penetrations, the incremental operating reserve requirement becomes more significant. The current largest contingency exposure on the Ontario bulk power system is 900 MW. For the 6,000 MW and 8,000 MW wind penetration cases, the wind output dropped by more than 900 MW in ten minutes 4 times. The wind output dropped by more than 900 MW 10 times With 10,000 MW of wind, The results indicate that an increase operating reserve requirement can be expected in order to accommodate extreme drops in wind generation for the high wind penetration scenarios.

For several of the scenarios, the minimum net-load point (with wind) is significantly reduced as compared to the minimum load-alone point. This has serious implications for the online generation resources during the low load periods and may require curtailment of wind power output or other mitigation measures. For the 10,000 MW scenario, wind energy output below the minimum load point represents 25% of the yearly energy. This is a significant proportion of the yearly energy output. If the minimum load-wind point drops far enough down into the generation stack, then only less maneuverable generation units may be left to serve the load. A complicating factor is that, during these low load-wind periods, the variability of the load-wind deltas is greater than the load-alone deltas. In other words, the maneuverability burden on the units serving the load during these periods is greater.

For all wind scenarios, the increase in hourly and multi-hourly variability, as measured by σ, due to wind is relatively small (not more than 10% for any scenario). From an hourly scheduling point of view, even 10,000 MW of wind would not push the envelope much further beyond the current operating point. However, the amount and magnitudes of extreme one-hour and multihour net-load changes are significantly greater with high wind penetration. With the addition of 10,000 MW of wind, the maximum one-hour net-load rise increases by 34%, and the maximum one-hour net-load drop increases by 30%. This data indicates that with large amounts of wind, much more one-hour ramping capability is needed for secure operation. Clearly the longest sustained ramping (up and down) occurs during the summer morning load rise and evening load decline periods. During these periods, (and others) the units may need to ramp continually over three or more hours. For the year 2020 load with 10,000 MW of wind scenario, the maximum positive three-hour load-wind delta increases by 17% and the maximum negative three-hour delta increases by 33%. The detailed results clearly illustrate the fact that units will have to undergo sustained three-hour ramping more often, and ramp further with the addition of large amounts of wind.

The analysis shows that sudden (less than 10-minute) province-wide interruptions of wind generation power output are extremely unlikely and do not represent a credible planning contingency. When sudden changes in wind output do occur, the study shows that the spatial diversity of wind sites and wind groups would tend to limit the impact of individual site or group changes on the aggregate wind output. This includes the impact of extreme weather incidents such as windstorms and ice storms, which are two of the major concerns for wind tower structural integrity. However, windstorms in the form of hurricanes or tornadoes, and ice storms which are capable of severely damaging or toppling a wind structure move at finite speeds and are not capable of "sudden" wholesale damage to structures across Ontario within "ten minutes or less".