THE EFFECTS OF INTEGRATING WIND POWER ON TRANSMISSION SYSTEM PLANNING, RELIABILITY, AND OPERATIONS

Report on Phase 2:

System Performance Evaluation

Prepared for:

THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

Albany, NY

John Saintcross
Senior Project Manager

Prepared by:

GE ENERGY

ENERGY CONSULTING

Richard Piwko, Project Manager
Xinggang Bai
Kara Clark
Gary Jordan
Nicholas Miller
Joy Zimberlin

March 4, 2005

Foreword

This document was prepared by General Electric International, Inc. in Schenectady, NY. It is submitted to THE NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA). Technical and commercial questions and any correspondence concerning this document should be referred to:

RICHARD PIWKO
Power Systems Energy Consulting
General Electric International, Inc.
1 River Road
Building 2, Room 644
Schenectady, New York 12345
Phone: (518) 385-7610
Fax: (518) 385-9529
E-mail: Richard.piwko@ps.ge.com

Legal Notice

This report was prepared by General Electric International, Inc. as an account of work sponsored by THE NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA). Neither NYSERDA nor GE, nor any person acting on behalf of either:

1. Makes any warranty or representation, expressed or implied, with respect to the use of any information contained in this report, or that the use of any information, apparatus, method, or process disclosed in the report may not infringe privately owned rights.

2. Assumes any liabilities with respect to the use of or for damage resulting from the use of any information, apparatus, method, or process disclosed in this report.

Table of Contents

Appendices

Table of Figures

Table of Tables

1 Introduction

1.1 Background

In response to emerging market conditions, and in recognition of the unique operating characteristics of wind generation, the New York Independent System Operator (NYISO) and New York State Energy Research and Development Authority (NYSERDA) commissioned a joint study to produce empirical information that will assist the NYISO in evaluating the reliability implications of increased wind generation. The work was divided into two phases.

Phase 1, Preliminary Overall Reliability Assessment, was completed in early 2004. This initial phase provided a preliminary, overall, screening assessment of the impact of large-scale wind generation on the reliability of the New York State Bulk Power System (NYSBPS). This assessment included:

- Review of world experience with wind generation, focusing on regions that have integrated significant penetration of wind resources into their power grids
- Fatal flaw power flow analysis to determine the maximum power output at prospective wind generation sites that can be accommodated by the existing transmission system infrastructure, considering thermal ratings of transmission lines
- Reliability analysis to determine the contribution of prospective wind generation towards meeting New York State requirements for Loss Of Load Expectation (LOLE)
- Review of current planning and operating practices to identify New York State Reliability Council (NYSRC), Northeast Power Coordinating Council (NPCC), North-American Electric Reliability Council (NERC), and NYISO rules, policies, and criteria that may require modification to be compatible with high penetration of wind generation

Phase 2 builds on what was learned in Phase 1. A base case wind scenario with 3,300 MW of wind generation (10% of NY State peak load) was selected for analysis. Operation of the NYSBPS with 3,300 MW of wind was evaluated in numerous ways, considering impacts on the following aspects of grid performance:

- Reliability and generation capacity
- Forecast accuracy
- Operation of day-ahead and hour-ahead markets
- Economic dispatch and load following
- Regulation
- Stability performance following major disturbances to the grid.

Detailed analysis of economic impacts and evaluation of possible generator retirements were not included in the scope of this study.

Results of these Phase 2 analyses are presented in this report.

1.2 Wind Generation Scenario

Starting from the original 10,026 MW of wind generation at 101 sites evaluated in Phase 1, two alternate scenarios with 3,300 MW of wind generation were considered. The project team selected a scenario with 3,300 MW of wind generation in 33 locations across New York State. Table 1.1 shows the location (by zone) of the wind farms included in the study. The lower portion of Table 1.1 lists the "Superzones" used by NY State Department of Public Service (DPS) for the RPS study. Load zones within the New York Control Area are illustrated in Figure 1.1.

The wind generation in Zone K, Long Island, is located offshore. The rest of the sites are land-based wind farms. The 600 MW site in Zone K was divided into 5 separate wind farms for interconnection into the Long Island transmission grid. Thus, the 33 wind sites are modeled in loadflow and stability simulations as 37 individual wind farms.

The majority of the interconnections were at the 115kV voltage level and above. Four of the Long Island interconnections were at the 69kV voltage level. No interconnections were below 69kV.

As a point of reference, the NYISO queue of proposed new generation presently has a total of 1939 MW in wind projects.

Table 1.1 Study Scenario – Wind and Load MW by Zone

	Total Potential Wind Generation	2008 Noncoincident Peak Load	Wind MW in Study Scenario	Wind as % of Peak Load
Zone A	3,070	2,910	684.2	24%
Zone B	1,197	2,016	358.5	18%
Zone C	1,306	2,922	569.7	19%
Zone D	483	902	322.6	36%
Zone E	2,832	1,592	399.8	25%
Zone F	434	2,260	260.6	12%
Zone G	105	2,260	104.6	5%
Zone H	0	972	0.0	0%
Zone I	0	1,608	0.0	0%
Zone J	0	11,988	0.0	0%
Zone K	600	5,275	600.0	11%
sum	10,026	34,704	3300.0	10%
DPS Zn 1	8,887	10,342	2334.8	23%
DPS Zn 2	538	7,099	365.2	5%
DPS Zn 3	600	17,263	600.0	3%
sum	10,026	34,704	3300.0	10%

Notes: DPS Zn 1 = Zones A + B + C + D + E
DPS Zn 2 = Zones F + G + H
DPS Zn 3 = Zones I + K

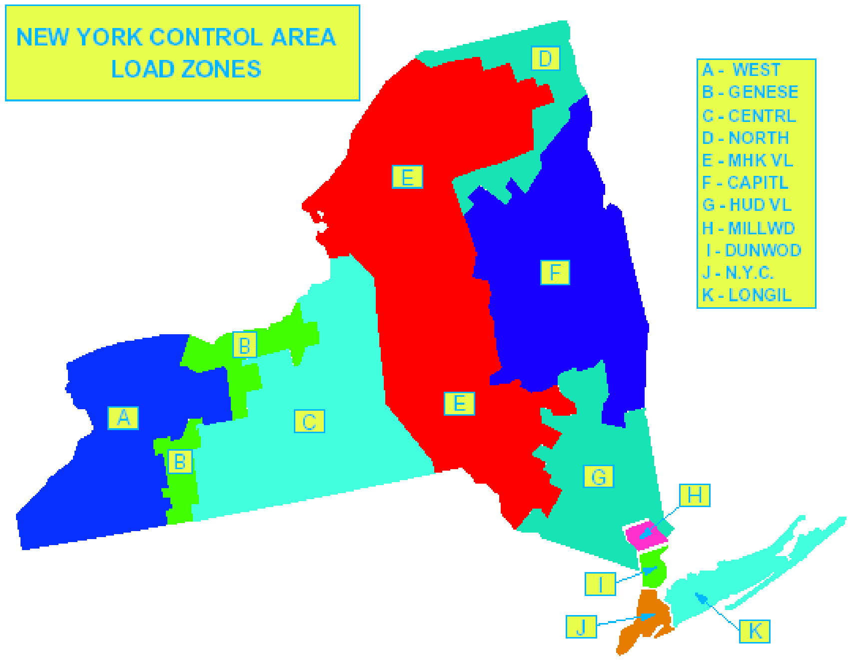

Figure 1.1 New York Control Area Load Zones

The majority of the wind generation in the study scenario is located in upstate NY, Zones A through E. In those zones, penetration of wind generation is 23% of peak zonal load. The 600 MW of offshore wind generation in Zone K represents 11% of peak load in that zone.

The model of the New York State Bulk Power System (NYSBPS) used in this study was derived from NYISO's 2008 transmission and generation modeled. Zonal load profiles were derived from measured data from years 2001-2003, scaled upward to be consistent with projected load levels in 2008. Selection of year 2008 for the study scenario is conservative, since 3,300 MW of operational wind generation is more than would be expected by that time.

Wind turbine-generators were assumed to have characteristics consistent with present state-of-the-art technology, and included continuously controllable reactive power capability (0.95 power factor at point of interconnection), voltage regulation, and low-voltage ride-through (LVRT).

1.3 Timescales for Power System Planning and Operations

The power system is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. The primary function of the power system is to serve a continuously varying customer load. From a control perspective, the load is the primary independent variable – the driver to which all the controllable elements in the power system must be positioned and respond. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and character) of load served by the system. The reliability of the system then becomes dependent on the ability of the system to accommodate expected and unexpected changes and disturbances while maintaining quality and continuity of service to the customers.

As illustrated in Figure 1.2, there are several time frames of variability, and each time frame has corresponding planning requirements, operating practices, information requirements, economic implications and technical challenges. Much of the analysis presented in this report is aimed at quantitatively evaluating the impact of significant wind variability in each of the time frames on the reliability and performance of the NYSBPS.

Figure 1.2 shows four timeframes covering progressively shorter periods of time. In the longest timeframe, planners must look several years into the future to determine the infrastructure requirements of the system. This timeframe includes the time required to permit and build new physical infrastructure. In the next faster timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this time frame, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. This is the fastest time frame in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made the day ahead are implemented and refined to meet the changing load. In NY State, the economic dispatch process issues load following commands to individual generators at 5-minute intervals. In the fastest time frame (at the bottom of the figure), cycle-to-cyle and second-to-second variations in the system are handled primarily by automated controls. The system automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e. are detected at the generating plant or substation). In addition, a subset of generators provide regulation by following commands from the centralized automatic generation control (AGC), to meet overall system control objectives including scheduled interchange and system frequency.

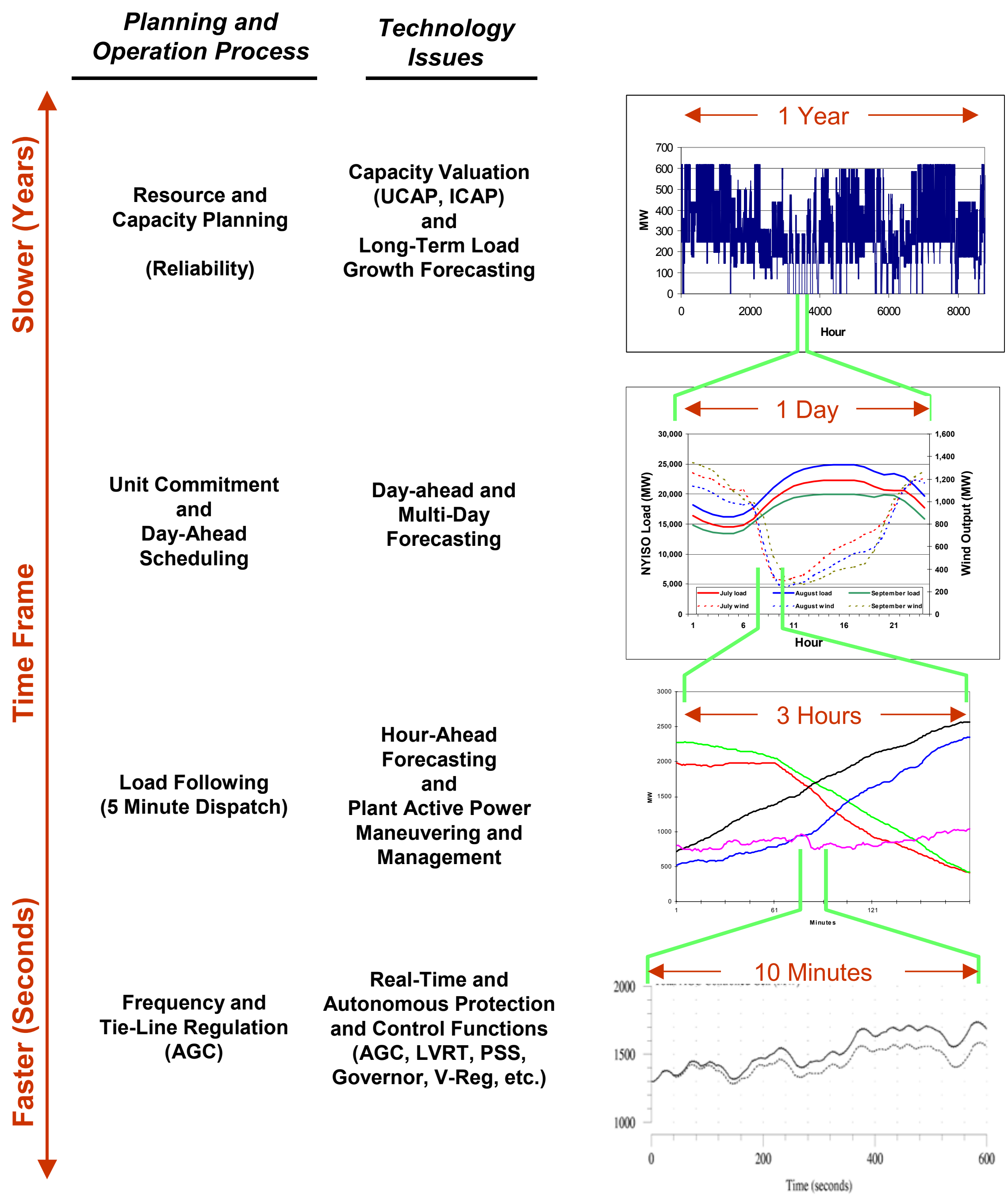

Figure 1.2 Time Scales for System Planning and Operation Processes

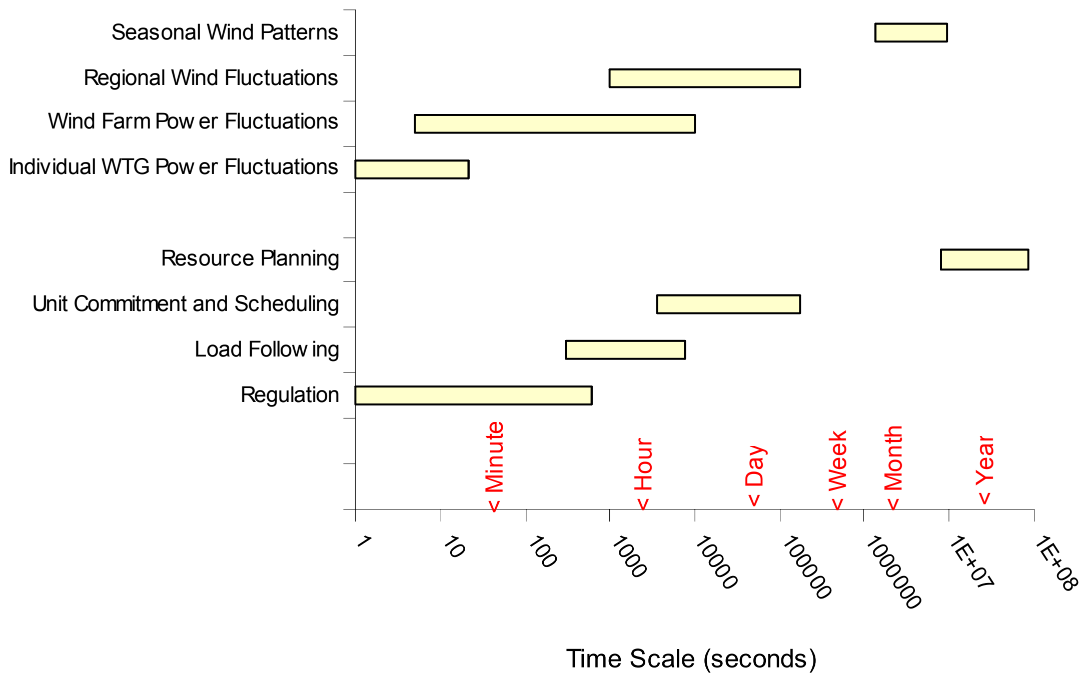

Figure 1.3 Wind Variability and Impact on System Operation Processes

Wind, as a variable and largely undispatchable generating resource, will impact all of these planning and operation processes. Wind variability has its own characteristics and time frames. As with system load, there are seasonal, diurnal, hour-to-hour , minute-to-minute and second-to-second variations. In the case of wind generation, as the time frame decreases the correlation between wind generating resources drops.[i] This is shown in the upper portion of Figure 1.3, where the spatial aspect of wind variation is correlated to the time-scale of temporal variations. Individual wind turbine-generators (WTGs) commonly experience power output variations in the one-second to several-minute timeframe. When many WTGs are grouped together in a wind farm, the short-term variations of individual WTGs are attenuated as a percentage of the aggregate, and the dominant power output variations for the entire wind farm occur in the minute-to-hour time frame. Similarly, the minute-to-minute power output of individual wind farms are attenuated in systems with multiple wind farms, leaving regional wind fluctuations in the hour-to-day time frame as the dominant system-wide effect. Seasonal wind patterns, of course, fall into the several-month timeframe.

The lower portion of Figure 1.3 shows how these wind variations relate to the four groups of planning and operation processes identified in Figure 1.2.

1.4 Technical Approach

The technical approach for this project addresses the range of processes involved in the planning and operation of the NYSBPS, over the range of timescales from seconds to years. The analysis focuses on the overall performance of the NYSBPS with a high penetration of wind generation, and does not address all localized effects related to each individual wind farm.

The bulk of the technical analysis was grouped into four major areas as described below.

1.4.1 Forecast Accuracy

The accuracy of the wind forecast affects unit commitment and operating reserve policies. Accuracy of wind generation forecasting was evaluated, and related to the historical accuracy of load forecasts used in the day-ahead market.

1.4.2 Wind and Load Variability

The NYSBPS already deals with significant variability in system load. Wind generation, as a variable power source, adds to the total variability that the NYSBPS must accommodate. The analysis of variability addressed the both major contributors to variability over several time frames:

Variability:
- Variability due to load alone
- Variability due to wind alone
- Combined variability due to load and wind, synchronized over the same calendar periods.

Time Frames:
- Hourly
- 5-minutes (load-following; economic dispatch)
- Seconds (regulation, AGC)

This analysis used consistent sets of historical wind data and historical load data, for the same time periods.

1.4.3 Operational Impact

Operational impacts cover a range of time scales, from seconds to multiple hours. Operation of the NYSBPS was simulated with and without wind generation (per the study scenario) as follows:

- Simulation of statewide operations for an entire year using MAPS, focusing on dispatch and unit commitment issues as a function of wind forecast accuracy.

- Quasi-steady-state simulation of selected 3-hour periods for wind and load variability, focusing on issues that affect load following.
- Stability simulation of selected 10-minute periods, focusing on regulation and other short-term control and protection issues (voltage regulation, low-voltage ride-through, AGC, etc.)

1.4.4 Effective Capacity

Using the Multi-Area Reliability Simulation (MARS) program, the effective capacity of wind generation, was quantified by comparing it with a typical fossil-fired power plant. This analysis includes consideration of the seasonal and diurnal variability in wind generation output relative to periods of peak system load, when generating resources have the greatest impact of overall system reliability as measured by loss-of-load probability (LOLP).

In addition to quantifying the likely range of unforced capacity (UCAP) for wind generation in NY State, approximate techniques for calculating the UCAP of individual wind farms were developed.

1.5 Data

Technical information and data for this study were obtained from the following sources:

- NYISO provided power flow and stability datasets, historical operating data for years 1999-2003, and contingency lists for the NYSBPS and NYSRC reliability datasets.
- AWS TrueWind provided data on potential wind generation sites in NY State, wind MW generation at those sites based on historical weather data, and technical information related to wind generation and wind forecasting.
- NYSDPS provided generation fuel cost and heat rate data from the preliminary RPS analyses.

Appendix A contains detailed descriptions of data provided by NYISO and AWS TrueWind.

2 Executive Summary

This study evaluated the impact of wind generation on the New York State Bulk Power System (NYSBPS) over a broad range of subject areas, including planning, operation, economics, and reliability. Key results and conclusions are summarized here. Details of the analysis, and the reasoning behind the conclusions, are further explained in Chapters 3-8.

2.1 Study Scenario for Wind Generation

The technical analysis for this study focused on a wind generation scenario that included a total of 3,300 MW of wind generation in 33 locations throughout New York State (see Table 2.1). Most of the wind sites are located upstate, but there is one large offshore facility near Long Island (Zone K). The total amount of wind generation (nameplate rating) in this scenario corresponds to approximately 10% of New York State's 2008 projected peak load. The majority of the wind farm interconnections were at the 115kV voltage level and above. Some interconnections for the Long Island site were at the 69kV voltage level. No interconnections were below 69kV.

Table 2.1 Wind Generation Included In Study Scenario

Location	Wind Generation MW	Wind Generation as % of 2008 Peak Load
Zone A	684.2	24%
Zone B	358.5	18%
Zone C	569.7	19%
Zone D	322.6	36%
Zone E	399.8	25%
Zone F	260.6	12%
Zone G	104.6	5%
Zone H	0.0	0%
Zone I	0.0	0%
Zone J	0.0	0%
Zone K	600.0	11%
Total for NY	3300.0	10%

Powerflow and operational models for the study scenario were derived from NYISO's 2008 system model. Hourly and shorter-term load profiles were based on actual historical data from years 2001-2003, but were scaled to match the projected load for 2008. Profiles of wind generation at the 33 locations were derived from historical weather records for years 2001-2003, so wind generation in the study scenario was treated as though the wind generators were actually in operation during those years.

Observations and conclusions presented in this report are based on analysis of this study scenario.

2.2 Impact on System Planning

A wide variety of standards, policies and criteria were reviewed to assess their impact on wind generation, and to determine if changes were needed to accommodate wind generation. In general, it was found that the existing rules and criteria could be applied to wind generation. A few specific items are discussed below.

2.2.1 NYISO System Reliability Impact Study (SRIS)

NYISO's SRIS is intended to confirm that a new facility complies with applicable reliability standards, to assess the impact of the new facility on the reliability of the pre-existing power system, to evaluate alternatives for eliminating adverse impacts (if any), and assess the impact of the new facility on transmission transfer limits. The SRIS policy is directly applicable to wind generation in its present form.

2.2.2 NYSRC Reliability Rules for Planning and Operation

NYSRC reliability rules are outlined in the document *NYSRC Reliability Rules for Planning and Operating the New York State Power System*, which addresses both resource adequacy and system security. A few minor changes related to planning studies are recommended:

The rules for steady-state analysis require evaluation of single-element (N-1) and extreme contingencies. Normally, loss of one generator in a multi-generator power plant would be a single-element contingency. Wind farms are comprised of many wind turbine-generators connected to a common interconnection bus. It is recommended that the loss of the entire wind farm be considered a single-element contingency for the purpose of NYSRC reliability criteria. However, simultaneous loss of multiple wind farms due to loss of wind in not a credible event. No changes to NYSRC rules for extreme contingencies, or multiple-element outages, are recommended.

NYSRC rules for stability analysis require evaluation of both design criteria and extreme faults. No changes to these rules or their interpretation are required for wind generation.

2.2.3 Generation Interconnection Requirements

In the Phase 1 report, it was recommended that New York State adopt some of the interconnection requirements that have emerged from the experiences of other systems. Specifically, New York State should require all new wind farms to have the following features:

- Voltage regulation at the Point-Of-Interconnection, with a guaranteed power factor range
- Low-voltage ride-through (LVRT)
- A specified level of monitoring, metering, and event recording
- Power curtailment capability (enables system operator to impose a limit on wind farm power output)

The above features are implemented in wind farms around the world, and are proven technology.

During Phase 2, technical analysis was performed to evaluate some of these features with respect to performance of the NYSBPS. Specifically, the impact of voltage regulation and low voltage ride through (LVRT) on system performance was demonstrated. The results showed that voltage regulation with a ±0.95 power factor range improves system response to disturbances, ensuring a faster voltage recovery and reduced post-fault voltage dips. In addition, LVRT ensures that wind farms remain connected to the NYSBPS under low voltage conditions due to faults or other system disturbances, and mitigates concerns about loss of multiple wind farms due to system events. Good performance was demonstrated with LVRT parameters that are less aggressive than the emerging industry consensus. It is recommended that New York adopt the emerging LVRT specification.

No operating conditions were found to justify the need for wind power curtailment at a statewide level (i.e., backing down all wind generators at the same time). However, for system reliability reasons, NYISO should require a power curtailment feature on new wind farms as a mechanism to posture the power system to handle temporary local transmission limitations (e.g., line out of service) or in anticipation of severe weather (e.g., intentionally curtail wind generation in advance of a severe storm affecting a large portion of the state). Such curtailment could be done by NYISO sending maximum power orders to wind farm operators (similar to the existing process for re-dispatching a thermal generator via the plant operator) or via SCADA for the case of unmanned generation facilities. This type of curtailment is envisioned as a farm-level function, not necessarily a turbine-level function. For example, if NYISO needed to limit power output of a specific wind farm due to a temporary transmission line outage, the wind farm operator could temporarily curtail generation by limiting output or shutting down a portion of the wind turbines in the wind farm. This is the same as would be done at any other dispatchable generating facility in New York State under the same circumstances.

Interconnection requirements are different for each transmission owner in New York State. In general, standards for interconnection of wind turbines are the same as for other generation.

Thus, frequency and voltage ranges, power factor ranges and other protection requirements remain largely unchanged. However, some features, such as governor control and power system stabilizer (PSS), are either technically impractical now or inappropriate for wind generators.

Presently, New York State has varied requirements for generator power factor. NERC Planning Standards require the following, "*At continuous rated power output, new synchronous generators should have an overexcited power factor capability, measured at the generator terminals, of 0.9 or less and an underexcited power factor capability of 0.95 or less*."[ii] Niagara Mohawk's requirements are consistent with those of NERC, but LIPA requires generators to have a power factor capability of 0.90 leading to 0.90 lagging at the point of delivery.

FERC NOPR RM05-4-000 (dated January 24, 2005) proposes that "*a wind plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the wind plant substation transformer(s)*."[iii] The requirement for measurement at the high side voltage recognizes the distributed nature of wind plants. The FERC NOPR power factor range measured at the high side bus is consistent with NERC requirements at generator terminals.

It is recommended that wind generation facilities meet power factor requirements consistent with other generation facilities in New York State and with existing local interconnection criteria, but translated to the high side voltage of the wind plant substation transformer. NYISO and New York State transmission owners may wish to re-evaluate the power factor requirements after FERC enacts a rule.

2.2.4 Future Interconnection Options

In the Phase 1 report, the following features were identified as emerging in response to system needs, and should be considered by New York State in the future as they become available:

- Ability to set power ramp rates
- Governor functions
- Reserve functions
- Zero-power voltage regulation

During Phase 2, technical analysis was performed to evaluate one of these features with respect to performance of the NYSBPS. Specifically, the ability to set power ramp rates for wind farms was demonstrated. The example ramp rate limit function resulted in a decrease in statewide regulation requirements at the expense of wind energy production. Therefore, such a function should only be used in specific applications to ensure system reliability.

2.3 Impact on System Operations

Table 2.2 provides a condensed summary of many key study results, arranged according to time scale. The following sections discuss each item in detail.

Table 2.2 Summary of Key Analytical Results for Study Scenario

Time Scale	Technical Issue	Without Wind Generation	With Wind Generation	Comments
Years	UCAP of Wind Generation	UCAP $_{\text{land-based}}$ ≅ 10% UCAP $_{\text{offshore}}$ ≅ 36% (one site in L.I.)		• UCAP is site-specific • Simple calculation method proposed
Days	Day-Ahead Forecasting and Unit Commitment	Forecasting error: σ ≅ 700-800 MW	Forecasting error: σ ≅ 850-950 MW	• Incremental increase can be accommodated by existing processes and resources in NY State • Even without forecasts, wind energy displaces conventional generation, reduces system operating costs, and reduces emissions. • Accurate wind forecasts can improve results by another 30%
Hours	Hourly Variability	σ = 858 MW	σ = 910 MW	• Incremental increase can be accommodated by existing processes and resources in NY State
	Largest Hourly Load Rise	2575 MW	2756 MW	• Incremental increase can be accommodated by existing processes and resources in NY State
Minutes	Load Following (5-min Variability)	σ = 54.4 MW	σ = 56.2 MW	• Incremental increase can be accommodated by existing processes and resources in NY State
Seconds	Regulation	225 to 275 MW	36 MW increase required to maintain same performance	• NYISO presently exceeds NERC criteria • May still meet minimum NERC criteria with existing regulating capability
	Spinning Reserve	1200 MW	1200 MW	• No change to spinning reserve requirement
	Stability	8% post-fault voltage dip (typical)	5% post-fault voltage dip (typical)	• State-of-the-art wind generators do not participate in power swings, and improve post-fault response of the interconnected power grid.

Note: σ = standard deviation

2.3.1 Forecasting and Market Operations

NYISO's day-ahead market presently uses day-ahead load forecasts as part of the generation commitment and scheduling process. The error between forecast load and actual load introduces a level of uncertainty that must be accommodated by NYISO's operating practices. Wind generation introduces another element of uncertainty. Analysis of wind forecast performance for the study scenario shows that errors in day-ahead wind generation forecasts have standard deviations of approximately 400 MW, or 12% of the aggregate rating of all the wind generators (3,300 MW).

Figure 2.1 shows the standard deviations of load forecast error, wind forecast error, and combined "Load minus Wind" forecast error for 11 selected months of years 2001-2003. The figure shows that total forecasting error (Load-Wind) is somewhat higher than the forecasting error due to load alone. For example, in the peak load months (points on the right-hand side), the total forecast error increases from 700-800 MW without wind generation (Load alone) to 850-950 MW with 3,300 MW of wind generation (Load-Wind). NYISO operational processes to deal with uncertainty in load forecasting already exist. The same processes can be used to handle the increase in forecast uncertainty due to wind generation.

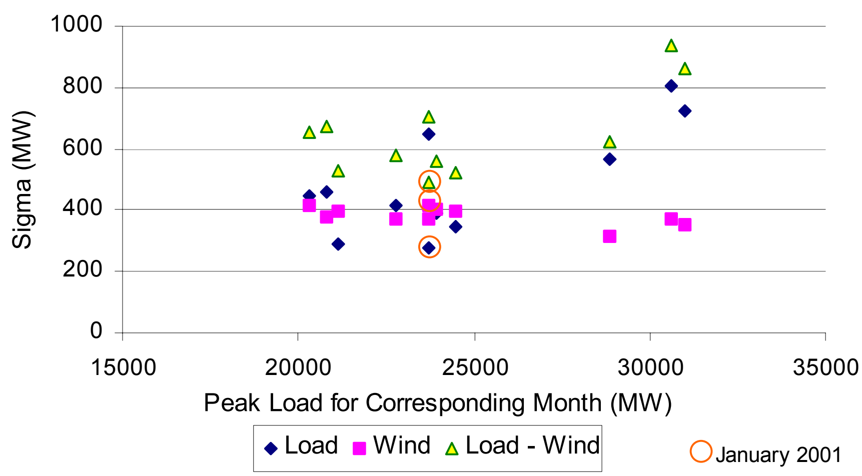

Figure 2.1 Standard Deviation of Day-Ahead Forecast Errors

Accuracy of wind forecasts improves as the lead-time decreases. For the study scenario, errors in hour-ahead wind generation forecasts are expected to have standard deviations of approximately 145 MW, or 4.2%.

Wind forecast uncertainties are of sufficient magnitude at the levels of penetration examined in this study to warrant the use of state-of-the-art forecasting. Data collection from existing and new wind farms should proceed immediately, in order to provide input to, and increase the fidelity of, wind forecasts for when the system achieves higher levels of penetration. New York should also consider meteorological data collection and analysis from proposed and promising wind generation locations in order to aid and accelerate the integration of high fidelity wind forecasting into NYISO's operating practices.

The existing day-ahead and hour-ahead energy markets in New York have sufficient flexibility to accommodate wind generation without any significant changes. It may also be advantageous for the forecasting to be performed from a central location to ensure a consistency of methodologies and so that changing weather patterns can be noted quickly. With these factors in place wind generation can be held accountable to similar standards as conventional generation in terms of meeting their day-ahead forecast, with one exception; imbalance penalties should not be imposed on wind generation Wind projects would need to settle discrepancies between their forecast and actual outputs in the energy balancing market. However, because wind is largely non-dispatchable, any additional penalties for imbalance should be eliminated. The FERC Order 888 allows imbalance *penalties* to be applied to generators that operate outside of their schedule. As applied in New York, any "overgeneration" can be accepted without payment and any "undergeneration" is priced at the *greater* of 150% of the spot price or $100/MWh. Strict application of these policies in the MAPS analysis performed would result in the loss of roughly 90% of the wind generation revenue, which would be disastrous to their future development. The intent of the penalties is to prevent generators from "gaming" the market but their application to intermittent resources such as wind and solar would result in negative and unintended consequences. If a wind generator forecasted 100 MW for a particular hour but can only produce 80 MW due to a lack of wind then no amount of penalties can get them to produce the remaining 20 MW. Their only option would be to bid less, or zero, in the day ahead market and possibly even bid low in the hour ahead market. However, the MAPS analysis showed that as much as 25% of the value of the wind energy to the system could be lost if it is not properly accounted in the day ahead commitment process. Any imbalance penalties for under-generation would tend to encourage underbidding the day ahead forecast, to the detriment of the entire system.

In order to take advantage of the spatial diversity of multiple plants, it may also be appropriate to aggregate wind generation on a zonal or regional basis rather than treating them as individual plants.

Wind forecasting may be performed in either a centralized or decentralized manner. With either approach, forecasts would be generated for each individual wind farm. However, centralized wind forecasting has several advantages that the NYISO may wish to consider:

- Application of a consistent methodology, which should achieve more consistent results across projects
- More effective identification of approaching weather systems affecting all wind plants, to warn the ISO of impending large shifts in wind generation
- Use of data from each plant to improve the forecasts at other plants. For example, a change in output of one plant might signal a similar change in other plants downstream of the first. Individual forecasters would not have access to the data from other projects to make this possible.

Care should be taken in the structuring of any financial incentives that may be offered to encourage the development of wind generation. The market for wind generation (including incentives) should be structured to:

- Reward the accuracy of wind generation forecasts, and
- encourage wind generators to reduce production during periods of light load and excessive generation.

The second item above is particularly critical to overall system reliability. If excessive wind generation causes the NYISO to shut down critical base-load generators with long shutdown/restart cycle times, the system could be placed in a position of reduced reliability. The market for wind power should be structured so that wind generators have clear financial incentives to reduce output when energy spot prices are very low (or negative).

2.3.2 Hourly Variability

Load and wind production vary from day-to-day and hour-to-hour, exhibiting characteristic diurnal patterns. The wind variability increases the inherent variability that already exists due to loads. Table 2.3 shows the changes in hourly variability due to the addition of wind generation, expressed as standard deviations (σ).

Table 2.3 Hourly Variability With and Without Wind Generation

	Without Wind	With Wind	Increase
Statewide	858 MW	910 MW	6%
Superzone A-E	268 MW	313 MW	17%
Zone K	149 MW	171 MW	15%

System operators give special attention to periods of peak demand and rapid rise in load. The summer morning load rise, especially during periods of sustained hot weather, presents one of the more severe tests to the system. Figure 2.2 shows the hour-to-hour variability for the load rise period for mornings during June through September. The natural diurnal tendency for wind generation to fall off during this period causes higher rates of rise. In this sample, 31% of the hours have rise rates greater than 2,000 MW/hr without wind, with the worst single hour rising 2,575 MW. With the addition of wind generators, this increases to 34% of hours with rise rates greater than 2,000 MW/hr, and the worst single hourly rise is 2,756 MW. Existing NYISO operating practices are expected to accommodate this increase.

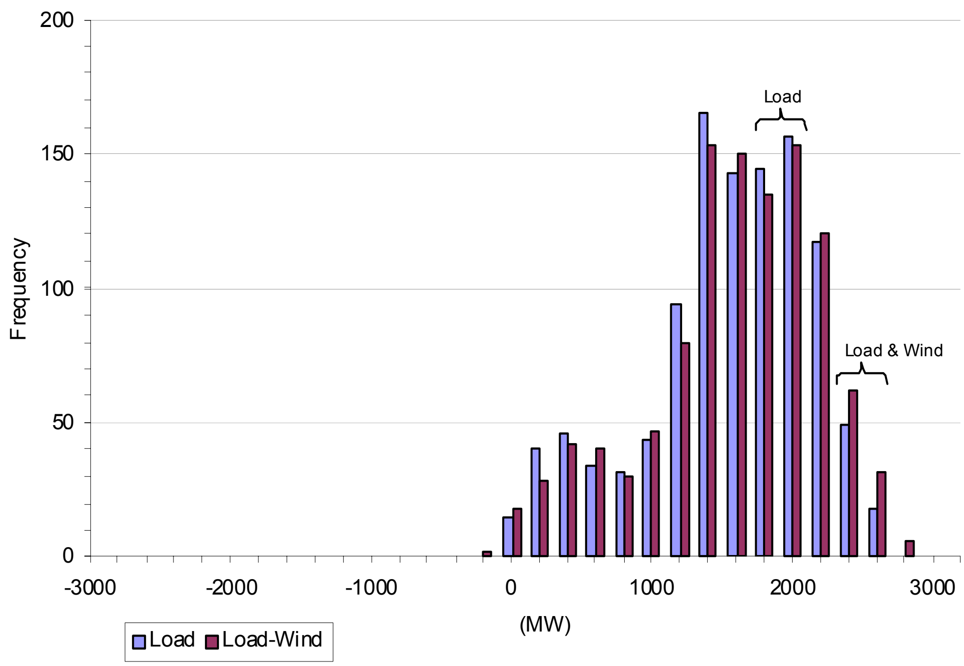

Figure 2.2 Summer Morning Load Rise - Hourly Variability

2.3.3 Load-Following

The impact of 3,300 MW of wind generation imposed on existing load-following performance was evaluated by both statistical analysis and time-response simulations.

NYISO sends economic dispatch commands to generators at 5-minute intervals. Statistical results are summarized as a histogram in Figure 2.3, showing the distribution of 5-minute changes in load with and without wind. These results indicate that wind generation would introduce only a small increase in the load-following duty for generators on economic dispatch. The standard deviation of the statewide samples increases by 1.8 MW (3%), from 54.4 MW without wind generation to 56.2 MW with wind generation.

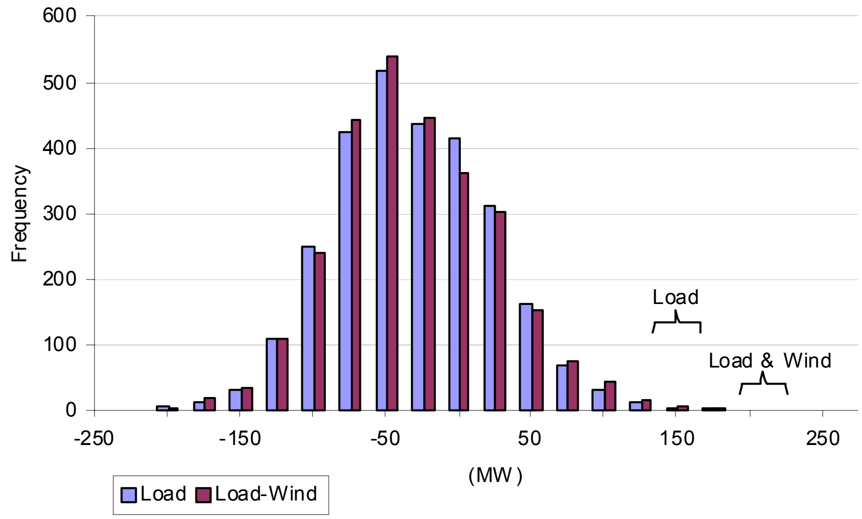

Figure 2.3 Five-Minute Statewide Variability

Quasi-steady-state (QSS) time simulations were performed to evaluate load-following performance during selected periods when both load and wind experienced large changes (e.g., rising load while wind generation declines, and vice-versa). The simulations were for load and wind profiles near the upper extremes of both Figure 2.2 and Figure 2.3, as indicated by the annotations on the figures. The results show that the existing economically dispatched generators would accommodate the increase in load-following duty.

2.3.4 Regulation

NYISO's automatic generation control (AGC) system maintains intertie flows and system frequency by issuing power commands to the regulating units at 6-second intervals. Existing operating practices require 225 MW to 275 MW of regulating units on-line, depending on the season. The impact of 3,300 MW of wind generation imposed on the existing regulating scheme was evaluated by both statistical analysis and stability simulations.

The statistical analysis of the study scenario shows that the standard deviation (σ) of 6-second variability due to load alone is 71 MW. As a check of existing regulation practice, this result suggests that 3σ, or 213 MW, of regulation would cover 99.7% of the time. With the addition of 3,300 MW of wind generation, the standard deviation increases from 71 MW to 83 MW. This implies that a 36 MW (3σ) increase in regulating capability will maintain the existing level of regulation performance with the addition of 3,300 MW of wind generation. Stability simulations covering selected 10-minute periods produced similar results.

This conclusion is further reinforced by the results of the 5-minute variability analysis. Variations in periods less than five minutes are addressed by regulation, while longer-term variations are addressed by economic dispatch (load-following). The analysis shows the standard deviation of combined load and wind variability for 5-minute periods is 56.2 MW (up from 54.4 MW due to load alone).

NYISO regulation performance (CPS1 and CPS2) presently exceeds NERC criteria. It is possible that the NYISO grid could accommodate 3,300 MW of wind generation with no increase in NYISO's regulation capability, and still meet minimum NERC criteria.

2.3.5 Spinning Reserves

Spinning reserves are required to cover the largest single contingency that results in a loss of generation. The present requirement is 1,200 MW. Analysis of historical statewide wind data indicates that loss of all wind generation due to abrupt loss of wind in not a credible contingency, and hence, the spinning reserve requirement would not be affected. Short-term changes in wind are stochastic (as are short-term changes in load). A review of the wind plant data revealed no sudden change in wind output in three years that would be sufficiently rapid to qualify as a loss-of-generation contingency.

2.3.6 System Operating Costs

GE's Multi-Area Production Simulation (MAPS) program was used to simulate the hourly operation of the NYSBPS for several years, with and without wind generation per the study scenario. Several different techniques for integrating wind generation into NYISO's unit commitment and day-ahead market were considered. The most likely approach involves using day-ahead wind generation forecasts for the unit commitment process, and scheduling wind generation before hydro. The process essentially shifts hydro generation within a several day period to make the best use of wind resources when they are available. Operating cost impacts for this approach are summarized in Table 2.4, based on the 2001 historical hourly load and wind profiles. (Note: System-wide impacts include NYISO, ISO-NE, and PJM.) The MAPS simulation results also indicate a $1.80/MWh average reduction in spot price in New York State.

Table 2.4 Annual Operating Cost Impacts for 2001 Wind and Load Profiles
(Unit commitment based on wind generation forecast)

	System-Wide	NYISO
Total variable cost reduction *(includes fuel cost, variable O&M, start-up costs, and emission payments)*	$ 430M	$ 350M
Total variable cost reduction per MW-hour of wind generation	$48 / MWh	$39 / MWh
Wind revenue	$ 315M	$ 315M
Non-wind generator revenue reductions	$ 795M	$ 515M
Load payment reductions *(calculated as product of hourly load and the corresponding locational spot price)*	$ 515M	$ 305M

The operating costs depend on how the wind resources are treated in the day-ahead unit commitment process. If wind generation forecasts are not used for unit commitment, then too many units are committed and efficiency of operation suffers. The operating costs for this situation are summarized in Table 2.5. In this case, unit commitment is performed as if no wind generation is expected, and wind energy just "shows up" in the real time market. The results indicate that energy consumers benefit from greater load payment reductions, but non-wind generators suffer due to inefficient operation of committed units. Comparing the system-wide variable cost reductions for these two cases, there is a $430M-$335M = $95M annual benefit to be gained from using wind energy forecasts for day-ahead unit commitment.

Table 2.5 Annual Operating Cost Impacts for 2001 Wind and Load Profiles
(Wind generation not included for unit commitment)

	System-Wide	NYISO
Total variable cost reduction *(includes fuel cost, variable O&M, start-up costs, and emission payments)*	$ 335M	$ 225M
Total variable cost reduction per MW-hour of wind generation	$38 / MWh	$25 / MWh
Wind revenue	$ 305M	$ 305M
Non-wind generator revenue reductions	$ 960M	$ 600M
Load payment reductions *(calculated as product of hourly load and the corresponding locational spot price)*	$ 720M	$ 455M

Any economic incentives that may be offered to wind generators should be designed to encourage use of state-of-the-art forecasting and active participation in the day-ahead power market.

2.3.7 Energy Displacement and Emission Reductions

Energy produced by wind generators will displace energy that would have been provided by other generators. Considering wind and load profiles for years 2001 and 2002, 65% of the energy displaced by wind generation would come from natural gas, 15% from coal, 10% from oil, and 10% from imports. As with the economic impacts discussed above, the unit commitment process affects the relative proportions of energy displaced, but the general trend is the same regardless of how wind generation is treated in the unit commitment process.

By displacing energy from fossil-fired generators, wind generation causes reductions in emissions from those generators. Based on wind and load profiles for years 2001 and 2002, annual NOx emissions would be reduced by 6,400 tons and SOx emissions would be reduced by 12,000 tons.

2.3.8 Transmission Congestion

Because most of the wind generation is located in upstate New York, transmission flows increase from upstate to downstate with the addition of wind generation. Figure 2.4 shows a time-duration curve of the UPNY-SENY (upstate New York to Southeast New York) interface flow for year 2008, with and without wind generation per the study scenario. Without wind generation, interface flow is at its limit for approximately 1100 hours. Wind generation increases the number of hours at limit to 1300. Most of the time, the interface is not limited and increased flows due to wind generation are accommodated.

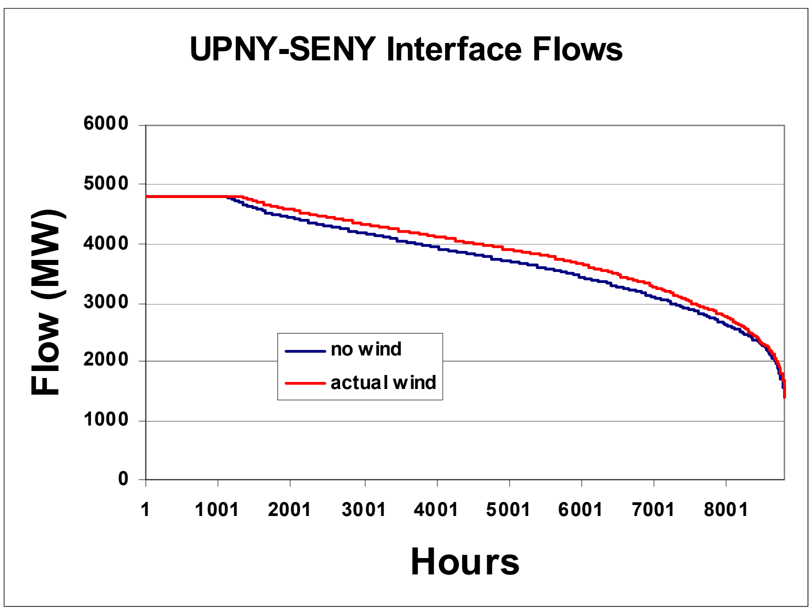

Figure 2.4 Duration Curve of Hourly Flows on UPNY-SENY Interface

2.4 Impact on System Reliability

2.4.1 Effective Capacity of Wind Generators

The effective capacity of wind generation in the study scenario was quantified using rigorous loss-of-load probability (LOLP) calculations with the Multi-Area Reliability Simulation (MARS) program. The results show that the effective capacities, UCAP, of the inland wind sites in New York are about 10% of their rated capacities, even though their energy capacity factors are on the order of 30%. This is due to both the seasonal and daily patterns of the wind generation being largely "out-of-phase" with NYISO load patterns. The offshore wind generation site near Long Island exhibits both annual and peak period effective capacities on the order of 40% - nearly equal to their energy capacity factors. The higher effective capacity is due to the daily wind patterns peaking several hours earlier in the day than the rest of the inland wind sites and therefore being much more in line with the load demand.

An approximate methodology for calculating effective capacity, UCAP, of wind generation was demonstrated. A wind generator's effective capacity can be estimated from its energy capacity factor during a four-hour peak load period (1:00 pm to 5:00 pm) in the summer months. This method produces results in close agreement with the full LOLP analytical methodology.

2.4.2 System Stability

The transient stability behavior of wind generation, particularly vector controlled WTGs, is significantly different from that of conventional synchronous generation. The net result of this behavior difference is that wind farms generally exhibit better stability behavior than equivalent (same size and location) conventional synchronous generation. In fact, simulation results demonstrate that overall stability performance of the NYSBPS is better with 3,300 MW of wind generation than it is without wind generation. Both post-fault voltage dips and oscillations in interface flows are improved with the addition of vector controlled wind turbine-generators.

It is recommended that New York State require all new wind farms to include voltage regulation and low voltage ride through (LVRT) features. Voltage regulation improves system response to disturbances, ensuring a faster voltage recovery and reduced post-fault voltage dips. LVRT ensures that wind farms remain connected to the NYSBPS under low voltage conditions due to faults or other system disturbances. Good performance was demonstrated with LVRT parameters that are less aggressive than the emerging industry consensus. However, it is recommended that NYS adopt the emerging LVRT specification (15% voltage at the point of interconnection for 625 milliseconds), consistent with the recent FERC NOPR on wind generation interconnection requirements.

2.5 Conclusions

Based on the results of this study, it is expected that the NYSBPS can reliably accommodate at least 10% penetration, 3,300 MW, of wind generation with only minor adjustments to its existing planning, operation, and reliability practices. This conclusion is subject to several assumptions incorporated in the development of the study scenario:

- Individual wind farms installed in NY State would require approval per the existing NYISO procedures, including SRIS.
- Ratings of wind farms would need to be within the capacity of local transmission facilities, or subject to local constraints.
- Wind farms would include state-of-the-art technology, with reactive power, voltage regulation, and LVRT capabilities consistent with the recommendations in this report.

3 Forecast Accuracy

3.1 Variability and Predictability

Reliable and economic operation of power systems requires good information about the present and expected future condition of the system. It is in this context that a brief examination of variability and predictability is warranted.

The variability of load on a seasonal and diurnal (daily) basis is mostly known and understood. All aspects of power system planning and operations are geared towards handling these variations. Load forecasts are used in three of the four time frames shown in Figure 1.2: resource planning (years ahead), unit commitment and scheduling (day-ahead), and load following (hour-ahead to 5 minute economic dispatch). Of course, perfect prescience is impossible, and the power system relies on various operating strategies to maintain the resilience necessary to provide reliable service subject to the inevitable inaccuracies in forecasts.

Variation in load is expected and can be predicted to a reasonable level of accuracy. The same is true for wind generation and other forms of non-dispatchable generation. Unlike dispatchable central station generation, most renewable resources, including wind, will produce power when conditions external to the power system (i.e., wind speed, insolation, rain run-off, etc.) dictate. It is the characteristics of these externalities that dictate both the variability and predictability of the resources. Figure 3.1 helps illustrate the important distinction between variability and predictability. In this figure, a range of non-dispatchable resources is placed to illustrate their relative variability and predictability. Non-dispatchable resources that rely on a steady supply of fuel or input energy, or which require a steady process, are both predictable and invariant. Digester type biomass and geothermal plants are good examples of this type of non-dispatchable resource. Tidal power is an example of a perfectly predictable but variable resource. The exact power production of a tidal plant can be predicted arbitrarily far in advance, but the four relative maxima and minima of power production per day mean that the resource is quite variable. The diurnal cycling of solar power means that it is highly predictable in the sense of being unavailable at night, but still subject to the weather related uncertainties of sunlight during the day. Wind will exhibit broadly predictable variation with season and daily cycling, but relative to the other resources in the figure will tend to show more variability that is somewhat less predictable that the other resources in the figure.

In broad terms, system operation relies on committable and dispatchable generation to meet the uncertain variations in the system. Non-dispatchable variable resources, such as wind generation, add to the inherent load variations and expand the duty on the dispatchable generation in the system. The balance of this section is focused on examination of the predictability of load and wind variability, and the implications for system operations. The actual impact of that variability on NYSBPS will be examined further in subsequent sections.

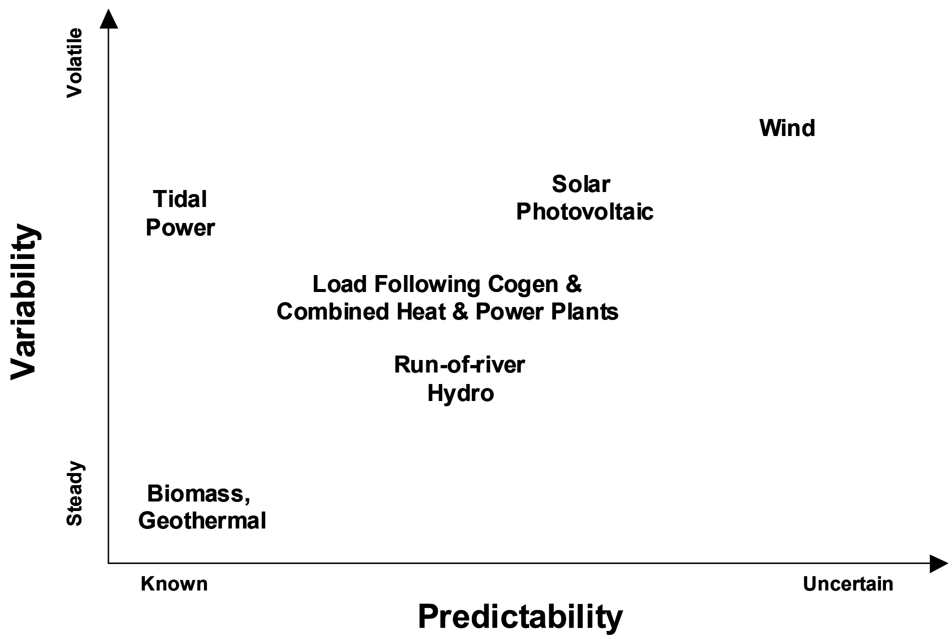

Figure 3.1 Variability and Predictability of Non-dispatchable Generating Resources.

3.2 Day-Ahead Forecasting

Reliable and economic operation of power systems requires good information about the present and expected future condition of the system. Day-ahead forecasting plays a crucial role in system operations, enabling the system to be positioned for secure and economic operation the following day. Forecasting is one of the key mechanisms by which the system operator reduces the degree of uncertainty in events and conditions for which the system must be prepared.

3.2.1 Day-Ahead Load Forecasting

Day-ahead load forecasting is based on a combination of long-term historical trends, recent weather and load history, and weather forecasts. Prior to November 1, 2001, the NYISO forecasting process used the larger of zonal load forecasts submitted by the load serving entities (LSEs) and the NYISO forecast, which resulted in a conservative or "biased" New York Control

Area load forecast. (i.e., the forecast load was consistently greater than actual load). After this date, the NYISO modified its day-ahead load forecasting process to an "unbiased" methodology

3.2.2 Day-Ahead Wind Forecasting

Wind forecasting is also based on history and weather forecasts. The historical aspects relate the specific behavior (i.e., power production) of a specific site to the broader predictions from meteorology. The forecasting data presented in this section is based on state-of-the-art techniques applied to each individual wind farm in the study scenario. The forecast data is based on the actual regional weather conditions, which were also a major factor in the corresponding system loads at the time. The report "Overview of Wind Energy Generation Forecasting"[iv] by AWS TrueWind provides a more complete discussion of the method and source of wind forecast data used in the analysis presented in this section.

The accuracy of wind forecasting is a function of the method used and the completeness of the site-specific power production history. Methods for quantifying the accuracy of wind forecasts vary. One commonly used metric of forecast accuracy is the "mean absolute error," or MAE. The MAE is the average of the absolute value of the difference between predicted power output and actual power output and is expressed as a percent of installed nameplate rating. Figure 3.2 shows MAE trends for a single wind farm for present state-of-the-art forecasting methods. Since the MAE is expressed on the percent of installed nameplate rating, the error expressed as a percent of actual power (or energy) produced is generally substantially higher. Unsurprisingly, the trend is that the farther in the future, the higher the error. These methods can achieve accuracies on the order of 13% to 21% MAE for day-ahead forecasting, by individual wind farm,.[v] The MAE figures include the reality that individual hours can have very substantial errors, especially those associated with errors in anticipating the timing of significant changes in weather patterns. For example, the being off by a few hours in the prediction of the time when a weather front will pass a specific wind farm can result in large errors for the hours involved. Centralized, or at least coordinated, forecasting reduces these effects by providing a clearer regional picture of wind patterns and trends than can be achieved with only localized forecasting.

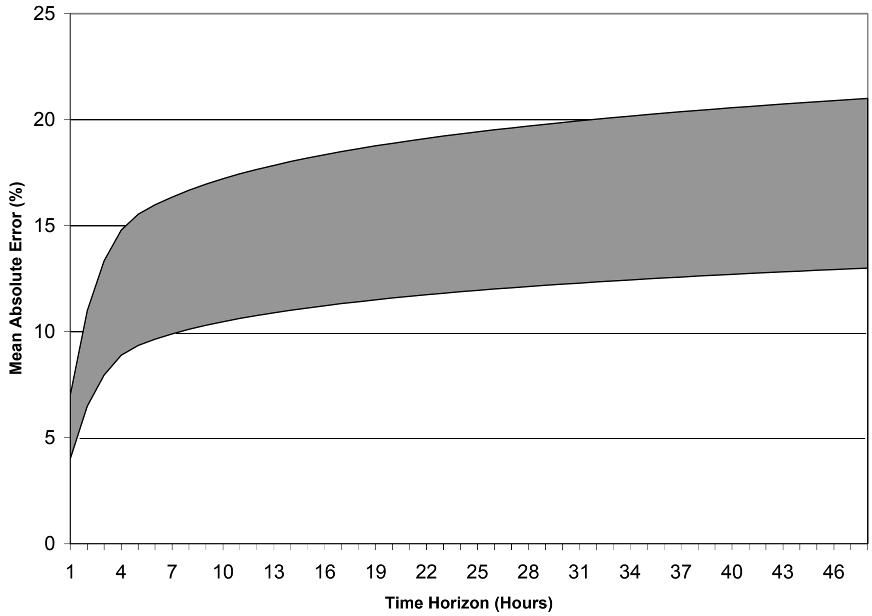

Figure 3.2 Wind Forecasting Accuracy for an individual Wind Farm

3.2.3 Discussion of Timing

As noted above, the daily rhythm of system operation includes day-ahead forecasting. It is useful to examine what "day-ahead" means in the context of forecasting and operations planning.

Figure 3.3 shows the sequence of key events related to day-ahead forecasting and unit commitment. The figure shows the day prior to the actual day of operation (which starts at 0:00 hr). In the upper left portion of the figure, the day-ahead load forecast is input to the day-ahead security constrained unit commitment (SCUC) software at NYISO at 5:00 am.[vi]

For wind forecasting, a primary input is the regional scale physics-based atmospheric model. Typically, these weather forecasts are executed at a national forecast center such as the National Center for Environmental Prediction (NCEP) operated by the U.S. National Weather Service. This forecast is used for a broad range of applications (transportation, defense, etc.) of which power systems operations is a subset. The weather forecast is used in the NYISO load forecast, and is used by the NYISO for security posturing of the system for extreme weather conditions[vii]. The weather forecast is issued at 12-hour intervals. For NYS, the weather forecast available at midnight GMT (29 hours before the day of operation) provides a window of ten hours for processing in wind forecasting software. The resultant day-ahead wind forecast would be delivered to the day-ahead SCUC software also at 5:00 am and covers the entire next day. Thus, at 5:00 am, the day-ahead forecast actually ranges from 19 hours ahead (the midnight to 1:00 am hour) up to 42 hours ahead (the 11:00 pm to midnight hour). Fortunately, with state-of-the-art wind forecasting, the accuracy of the forecast for the last hour is nearly as good as for the first hour.

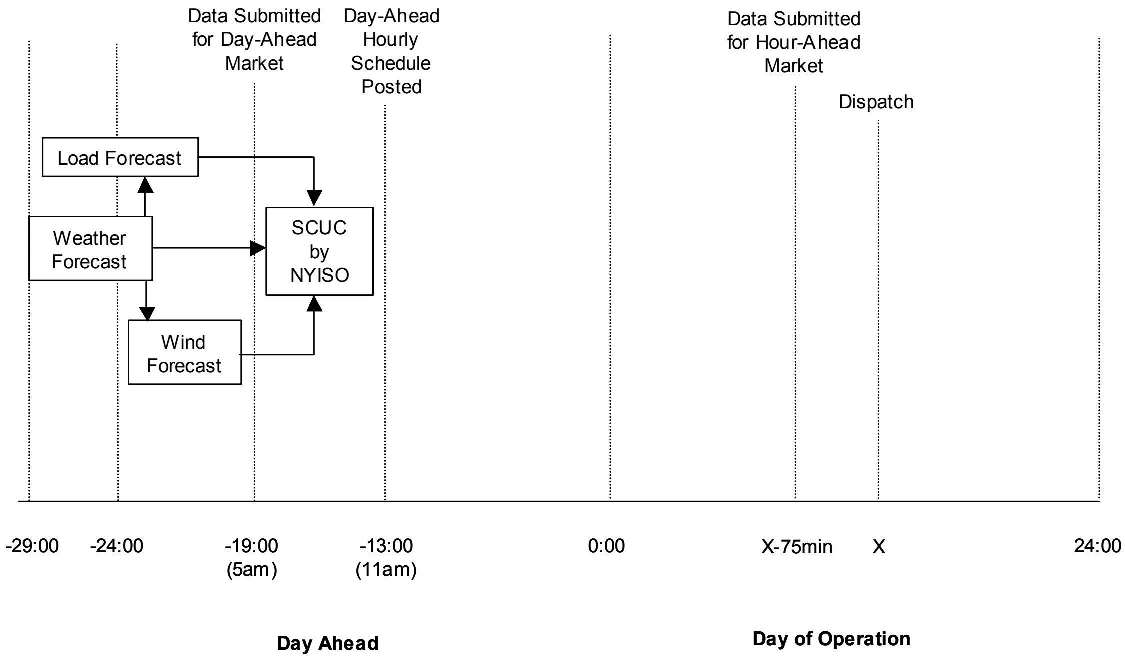

Figure 3.3. Timeline for Day-Ahead Forecasting

3.3 Day-Ahead Forecasting Error Analysis

Errors in load forecasting and wind generation forecasting are inseparable from a system-operation perspective. Errors in wind forecast are not particularly meaningful in isolation, but rather are relevant in so far as they impact decisions and reliability when compounded with errors in load forecasting. Thus, from a practical perspective, since the power system is designed and operated with the recognition that load behavior is not perfectly predictable, this analysis is aimed at examining the impact of the incremental uncertainties introduced by wind generation. In the first subsection below, detailed results of error analysis for a single month of system operation will be examined. Examination of a single month of operation has the benefit of providing good detail and yet a significant statistical sampling. A one-month sample makes it easier to observe daily and weekly trends. Analysis was performed on multiple months across multiple years, the results of which confirm the observations on this sample month. Summary of those results are presented in the next subsection. The impact of the change in NYS load forecasting methodology is addressed there.

3.3.1 Day-Ahead Forecasting Error Analysis for January 2001

The behavior shown in Figure 3.4 is illustrative of the relationship between load and wind generation. The sign convention is such that wind is treated as a load modifier; therefore load minus wind represents the net load that must be served by generation other than wind. The data plotted is for the entire state, including all the wind generation sites in the study scenario. The six traces, in the order listed in the legend, are as follows:

2001 Actual Load – the hourly load served statewide during January 2001.

2001 Load Forecast – the day-ahead load forecast provided to the NYISO SCUC.

Actual Total – The actual load minus the wind power that would have been produced at that time for the study wind generation scenario.

Forecast Total - The forecast load minus the forecast wind power.

Forecast Wind – The wind power that would have been forecast a day-ahead at that time for the study wind generation scenario during January 2001.

Actual Wind – The wind power that would have been produced at that time for the study wind generation scenario.

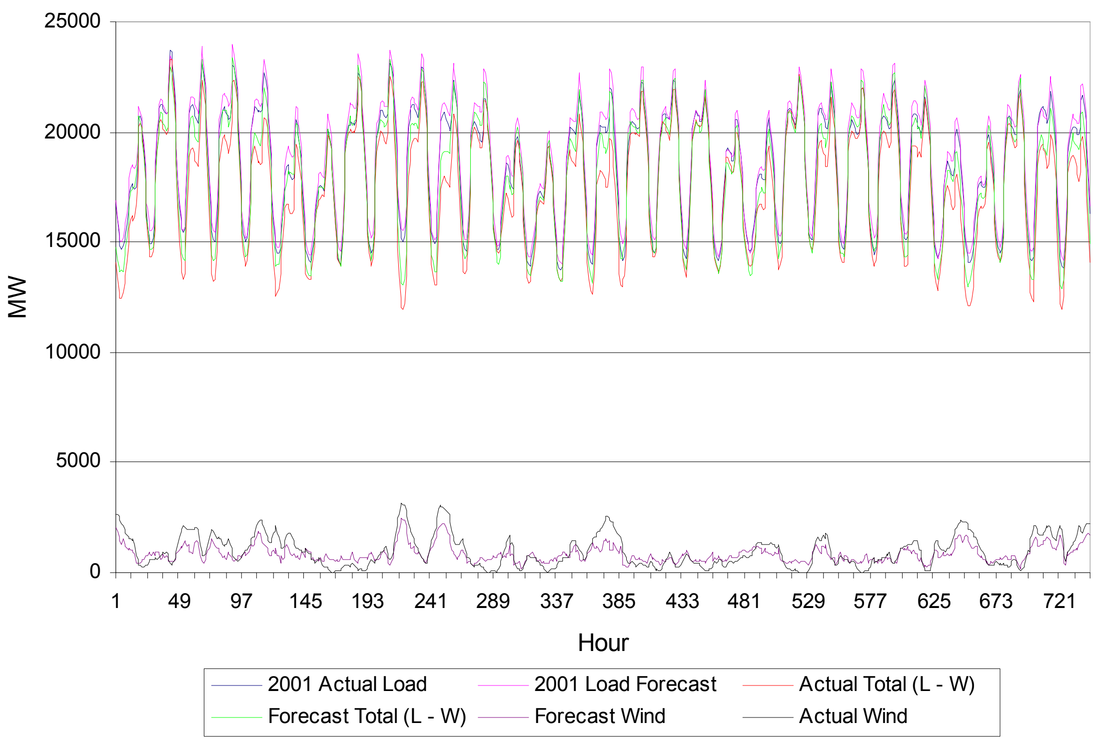

Figure 3.4 Day-Ahead Forecasts vs. Actual Hourly for January 2001

The figure shows the diurnal cycling and differences between weekdays and weekends. Since this is January, the peak daily load occurs in the evening. Overall, the figure shows that in broad-terms, the forecast behavior of the system tracks the actual behavior quite well.

The differences between forecast and actual behavior, the forecast error, can be seen more clearly in Figure 3.5. The three traces in the figure show the following, respectively:

Load Error - The difference between the forecast load and actual load.

Wind Error – The difference between the actual wind and forecast wind.

Total Error – The difference between the forecast total and the actual total.

Understanding the sign convention here is very important. The sign of the error for each trace is selected such that a positive error means the net requirement for generation resources (other than wind) is less than predicted. Thus, a positive error means that units will be over-committed and over-scheduled. Conversely, a negative error means that additional generation will be required beyond that which is predicted. In general, errors in both directions have economic consequences, but the reliability implications of under predicting (negative error) are somewhat more serious than for over-prediction.

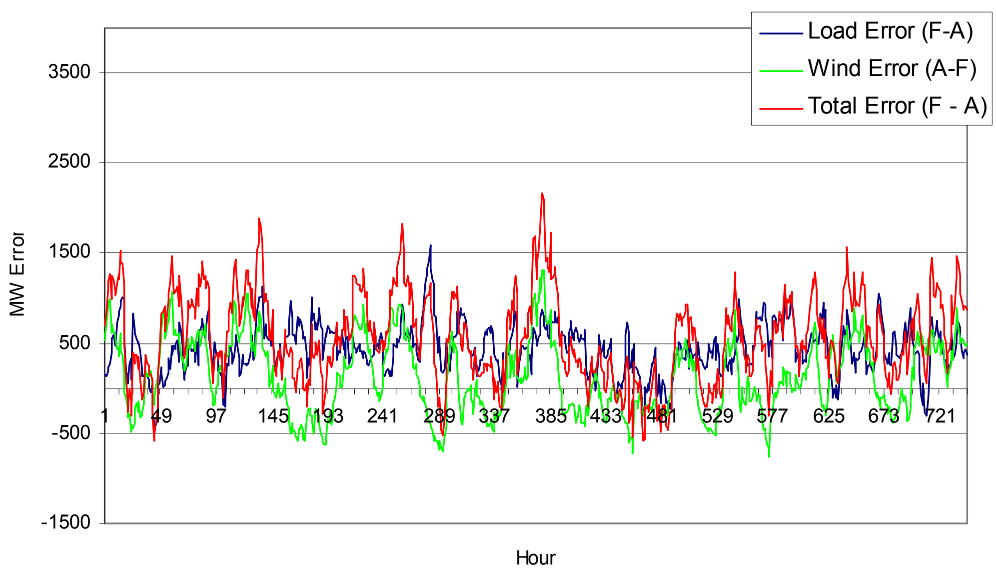

Figure 3.5 Day-Ahead Forecast Errors for January 2001

Overall, the total error (i.e., the error with wind generation present and included in the forecast) is slightly greater than the forecast error without wind. As expected, the total error may be less or greater than the load alone error, depending on the sign of the wind error relative to the load error.

Figure 3.6 shows the hourly duration curve for the three errors. Note that there are 744 hours in January. In this figure, it is easier to see that the load and wind error are not simply additive, (this is, the sum of the blue load error trace and the green wind error trace does not equal the red total trace). Rather they depend on the coincidence or lack thereof, in the errors. The zero crossings of the three traces define the transition from negative error (to the left of the zero crossing) and positive error (to the right).

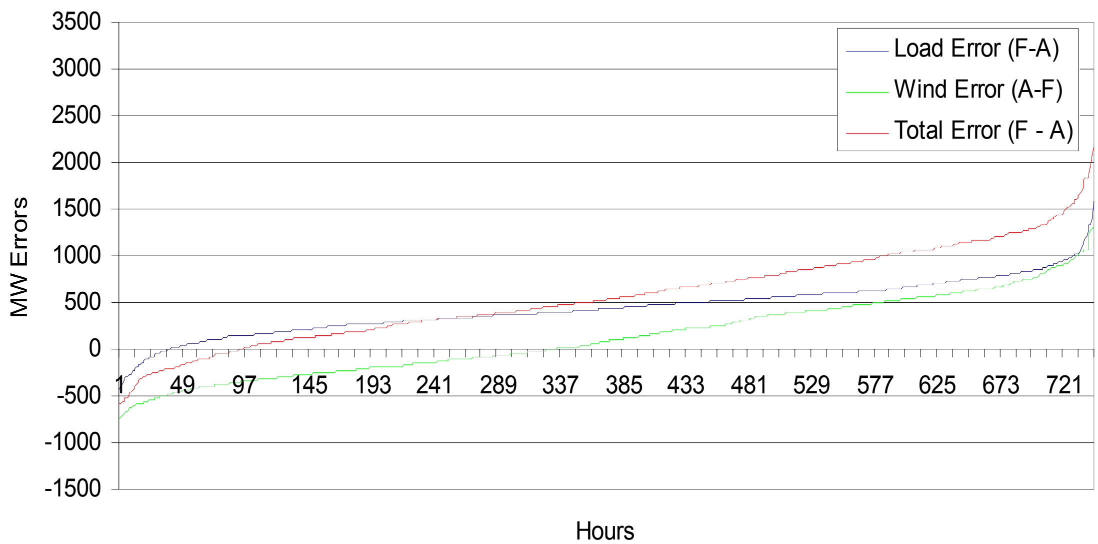

Figure 3.6 Day-Ahead Error Duration Curve for January 2001

The statistics on distribution of errors across the month are summarized in Table 3.1. The entries in the table, for each of the three quantities (columns) are as follows:

Hours Negative – The count of hours for which the forecast is low (i.e., more generation will be needed than predicted).

Hours Positive - The count of hours for which the forecast is high. (i.e., less generation will be needed than predicted).

Negative Energy Error – The total energy requirement (in MWh) under predicted (the area under zero and above the forecast error curve in Figure 3.6).

Positive Energy Error - The total energy requirement (in MWh) over predicted (the area above zero and below the forecast error curve in Figure 3.6).

Net Energy Error – The total error in energy requirement predicted (the integral of the forecast error).

Worst Negative Error – The extreme or worst hour under prediction (the leftmost point in the duration curve).

Worst Positive Error – The extreme or worst hour over prediction (the rightmost point in the duration curve).

Peak – The maximum actual load or wind generation for the month.

Min – The minimum actual load or wind generation for the month.

Energy – The total actual load or wind generation for the month.

Negative Energy Error – The total energy requirement under predicted expressed as a percentage of the total load energy served. (Entries for all three columns are normalized to the load energy in the first column).

Positive Energy Error – The total energy requirement over predicted expressed as a percentage of the total load energy served. (Entries for all three columns are normalized to the load energy in the first column).

MAE – Mean absolute error of the forecasts, expressed in MW.

STD on Error - The standard deviation (sigma, σ) of the forecast errors, in MW.

MAE % – Mean absolute error of the forecasts, expressed in percent of the installed MW of wind generation (3300 MW).

Table 3.1. Forecast Error Statistics for January 2001

2001 Jan Day Ahead	Load	Wind	Load - Wind
Hours Negative	39	329	94
Hours Positive	705	415	650
Negative Energy Error (MWh)	-6,058	-85,645	-18,655
Positive Energy Error(MWh)	332,772	180,573	440,297
Net Energy Error (MWh)	326,714	94,928	421,642
Worst Negative Error (MW)	-433	-753	-581
Worst Positive Error (MW)	1,581	1,310	2,174
Peak (MW)	23,720	3,149	23,273
Min (MW)	13,754	3	11,937
Energy (MWh)	13,719,259	723,591	12,995,668
Negative Energy Error(% of LE)	-0.04	-0.62	-0.14
Positive Energy Error(% of LE)	2.43	1.32	3.21
MAE (MW)	455	358	617
STD on Error (MW)	277	416	491
MAE (% of Rating Wind)	13.80	10.84	18.69

This table shows that errors in day-ahead load forecasting for this month result in over prediction of load energy of about two and half percent of the total load energy served. The biased load forecasting results in almost nil (about 6 GWhr) under prediction of load energy. The addition of wind increases the net over prediction by about 0.8%, or 100 GWhr. The under prediction increases about 0.1% (12 GWhr) due to wind forecast errors. These changes in errors are not expected to have any reliability impacts. The errors have the potential to increase economic inefficiencies due to suboptimal commitment. This is examined in Section 4, *Hourly Production Simulation Analysis*.

The table shows system-wide MAE for the month of 10.84%. This reflects the aggregate benefits of forecasting for multiple plants. The MAEs for the individual wind farms for the month are shown in Figure 3.7. They range from about 14 to 19%, and are consistent with state-of-the-art forecasting for individual plants.

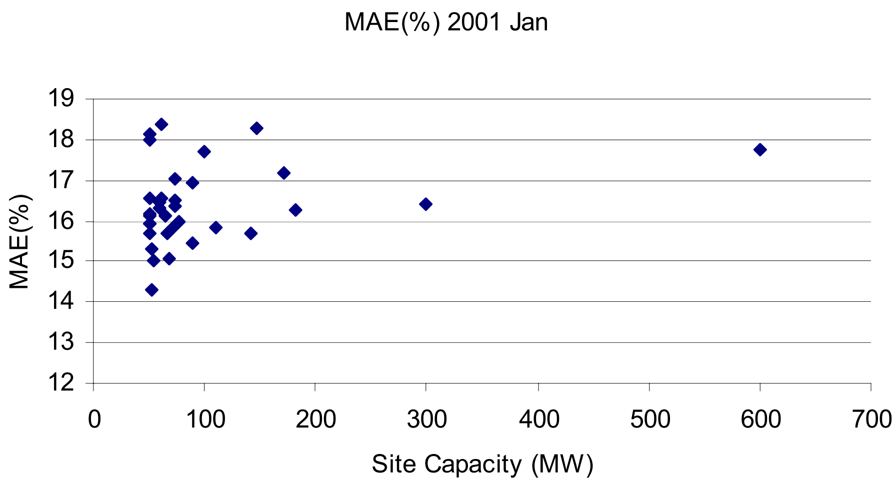

Figure 3.7 Mean Absolute Error (MAE) for Individual Wind Farms Forecasts - January 2001

3.3.2 Day-Ahead Forecasting Error Analysis for Multiple Months

Similar analysis was conducted on the following 10 months, for which data was available:

- April, August, October 2001
- January, April, August, October 2002
- January, April, August 2003

Detailed results for each month are included in Appendix B. The next sequence of figures shows results from the total eleven months of analyzed data. Figure 3.8 shows the standard deviation for the eleven months, plotted against the peak load for that month.

The standard deviation, usually denoted sigma (σ), provides a good index of expected behavior of variable phenomena. In a normal distribution 68% of events are within ±1σ, 95% of events are within ±2σ, and 99.7% of events are within ±3σ.

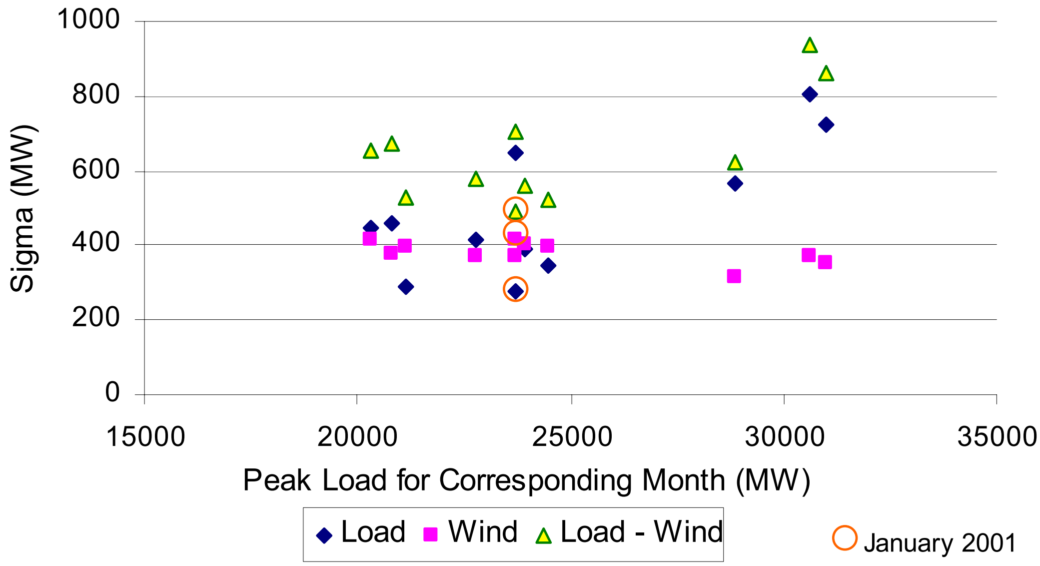

Figure 3.8 Standard Deviation of Day Ahead Forecast Errors

This figure shows that the total forecasting error (load – wind) is somewhat higher than the forecasting error due to load alone. For example in peak load months (points on the right hand of the plot), the forecast error increases from around 750-800 MW to about 850-950 MW. During lightest load months (left hand side) the forecast error increases from about 450 MW to 650 MW.

The sigmas for January 2001 are circled in the figure. The sigma for load forecast error was the lowest of the eleven moths, and the increase in sigma with the addition of wind (from 277 to 491 MW) was one of the largest. This is a confirmation that more detailed examination of January 2001 is conservative.

Since the operational implications of a positive error (excess generation will be scheduled) are different from those of negative error (less generation will be scheduled), it is useful to examine the two faces of error separately. Figure 3.9 shows the count of hours for which each of the forecasts errors is positive (these months have either 720 or 744 hours). Figure 3.10 shows the corresponding count of negative error hours. The load errors show a noticeable shift towards a more balanced split between negative and positive hours starting around April 2002. This appears to correspond to the NYISO moving to unbiased load forecasting in late 2001, though the effect becomes obvious somewhat later (i.e., April 2002 versus Jan 2002).

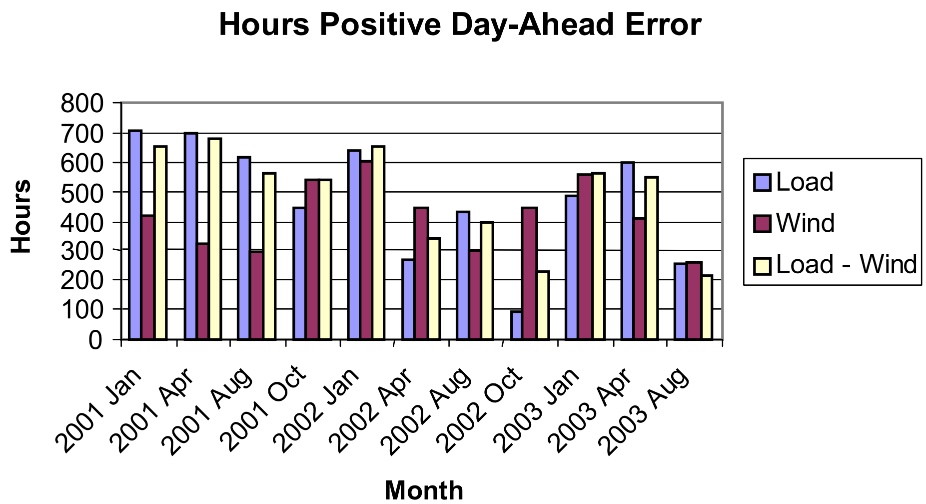

Figure 3.9 Day-Ahead Positive Forecast Error Frequency

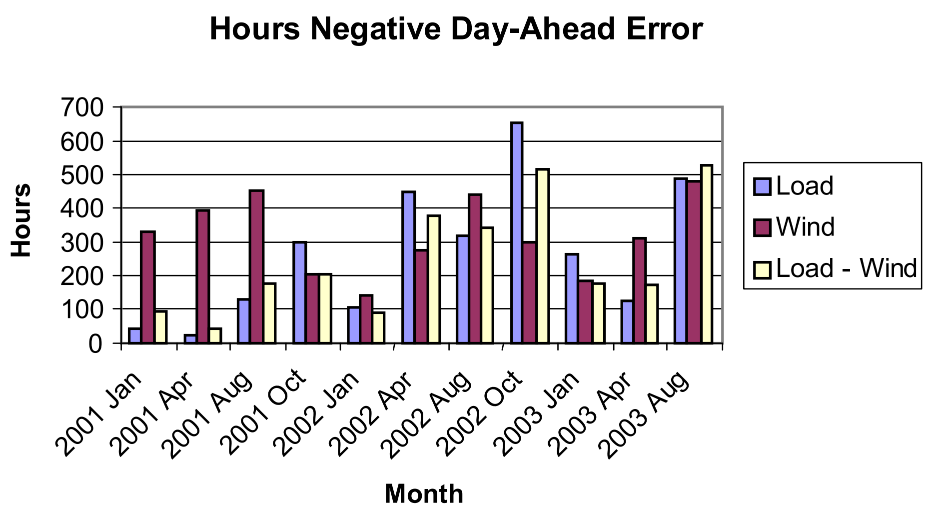

Figure 3.10 Day-Ahead Negative Forecast Error Frequency

The total energy involved in the forecast error is a means of quantifying the operational impact on the system. Figure 3.11 and Figure 3.12 show the total monthly energy associated with day-ahead forecast errors. Again, the shift in bias starting in April 2002 for the load forecast is quite apparent. Finally, the annual statistics corresponding to data in Table 3.1 are shown for each of the three years of available data in Table 3.2, Table 3.3 and Table 3.4. Again, the shift to unbiased load forecasting between 2001 and the later years is apparent in the data.

The system-wide MAE on the wind forecast varies between 10.17% and 10.80% across the three years. Again, these are consistent with state-of-the-art forecasting, which would produce MAE between 13% and 21% on an individual plant basis.

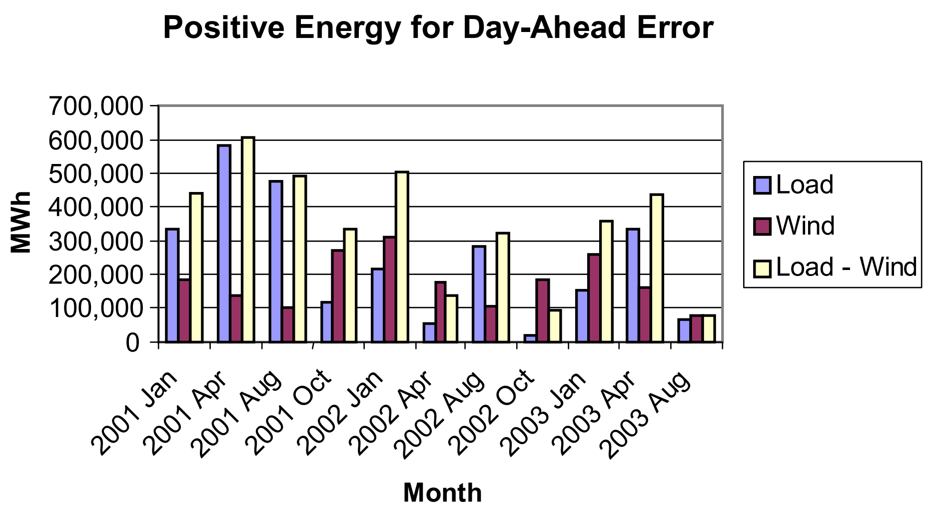

Figure 3.11 Positive Energy Error for Day-Ahead Forecasts

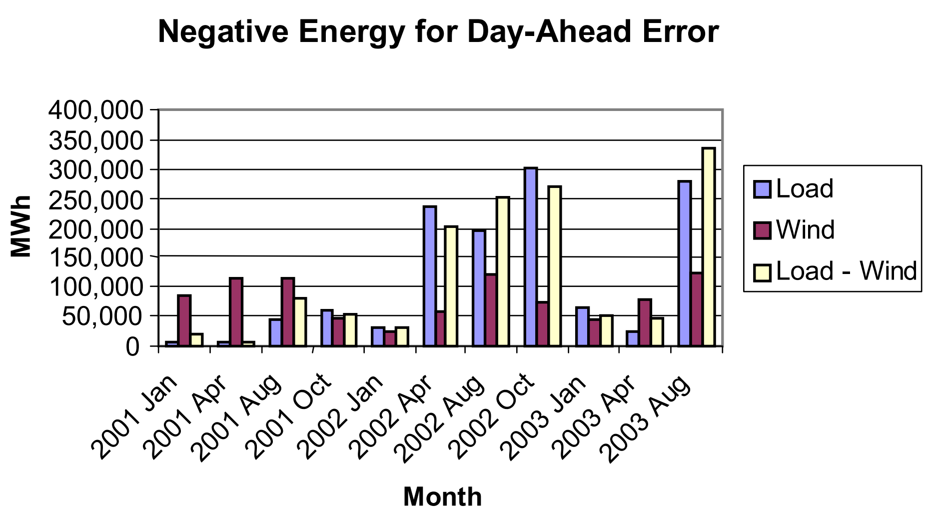

Figure 3.12 Negative Energy Error for Day-Ahead Forecasts

Table 3.2 2001 Day-Ahead Forecast Error Statistics (4 months)

2001 Day Ahead 4 Months	Load	Wind	Load - Wind
Hours Negative	490	1,380	516
Hours Positive	2,462	1,572	2,436
Negative Energy Error (MWh)	-115,714	-360,297	-162,788
Positive Energy Error(MWh)	1,505,209	681,498	1,873,484
Net Energy Error (MWh)	1,389,495	321,201	1,710,696
Worst Negative Error (MW)	-1,052	-770	-1,446
Worst Positive Error (MW)	3,569	1,310	3,485
Peak (MW)	30,982	3,149	30,596
Min (MW)	11,600	0	8,912
Energy (MWh)	53,619,075	2,917,948	50,701,127
Negative Energy Error(% of LE)	-0.22	-0.67	-0.30
Positive Energy Error(% of LE)	2.81	1.27	3.49
MAE (MW)	549	353	690
STD on Error (MW)	539	414	668
MAE (% of Rating Wind)	16.64	10.69	20.90

Table 3.3 2002 Day-Ahead Forecast Error Statistics (4 months)

2002 Day Ahead 4 Months	Load	Wind	Load - Wind
Hours Negative	1,525	1,157	1,324
Hours Positive	1,427	1,795	1,629
Negative Energy Error (MWh)	-765,532	-276,466	-751,578
Positive Energy Error(MWh)	577,488	775,975	1,063,043
Net Energy Error (MWh)	-188,044	499,509	311,465
Worst Negative Error (MW)	-3,398	-728	-3,654
Worst Positive Error (MW)	3,755	1,215	4,436
Peak (MW)	30,596	3,227	30,476
Min (MW)	11,705	0	9,690
Energy (MWh)	53,784,416	3,116,211	50,668,205
Negative Energy Error(% of LE)	-1.42	-0.51	-1.40
Positive Energy Error(% of LE)	1.07	1.44	1.98
MAE (MW)	455	357	615
STD on Error (MW)	644	405	785
MAE (% of Rating Wind)	13.79	10.80	18.63

Table 3.4 2003 Day-Ahead Forecast Error Statistics (3 Months)

2003 Day Ahead 3 Months	Load	Wind	Load - Wind
Hours Negative	878	979	878
Hours Positive	1,330	1,229	1,330
Negative Energy Error (MWh)	-363,028	-246,180	-434,364
Positive Energy Error(MWh)	552,405	495,155	872,717
Net Energy Error (MWh)	189,377	248,975	438,352
Worst Negative Error (MW)	-2,327	-842	-2,331
Worst Positive Error (MW)	2,030	1,332	2,415
Peak (MW)	30,596	3,215	30,476
Min (MW)	11,705	0	9,690
Energy (MWh)	41,019,162	2,354,595	38,664,567
Negative Energy Error(% of LE)	-0.89	-0.60	-1.12
Positive Energy Error(% of LE)	1.35	1.21	2.26
MAE (MW)	415	336	592
STD on Error (MW)	552	392	725
MAE (% of Rating Wind)	12.56	10.17	17.94

There is a significant monthly variance in the cumulative energy associated with forecast error. A comparison of the monthly errors, with and without wind, shows remarkably similar results. Most months are slightly worse, while a few are slightly better. Figure 3.13 shows the distribution of energy errors as a percent of the total energy served for the month. In most months, the negative energy error is about 2% or less of the total energy delivered, with wind forecast errors having little impact. The worse negative error occurs for October 2002, with no wind. During months with lower peak loading, the positive error tends to increase by about 0.5% to 2%; during peak load months, the impact is a fraction of one percent. The highest positive error is for April 2001, before NYISO changed to unbiased load forecasts. After changing to unbiased forecasting, the worst positive error is 2.8% without wind, and 3.7% with wind, an increase of 0.9%.

From an operational reliability perspective, the incremental forecast error associated with wind generation is within the range of uncertainty currently handled successfully in NYISO operations.

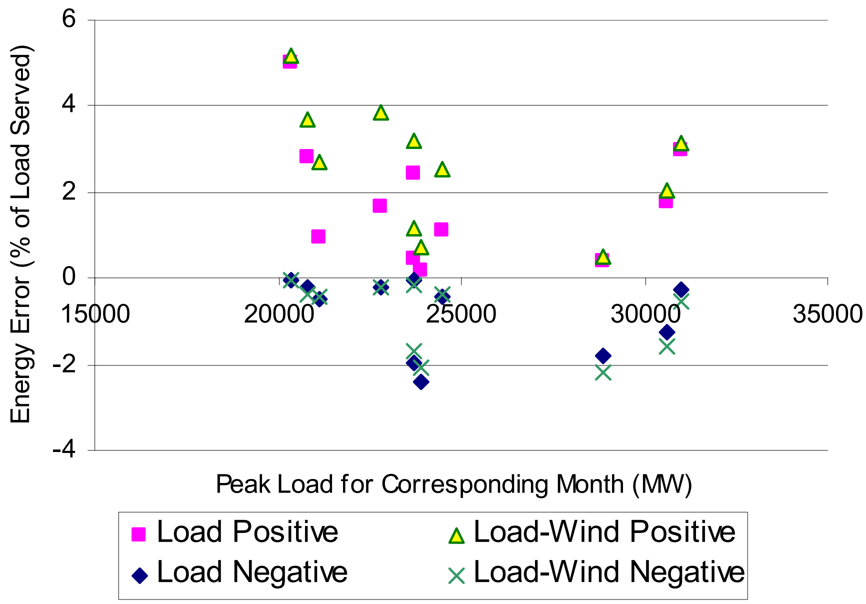

Figure 3.13 Distribution of Forecast Energy Errors

3.4 Hour-Ahead Forecasting

During daily operation, the NYISO updates its load forecast on an hourly basis. This forecast is used as input to the hour-ahead market, 75 minutes before the subject hour starts, as shown in Figure 3.3. The hour-ahead market provides an opportunity to update and refine the wind forecast in parallel with the load forecast. NYISO also performs a five-minute ahead load forecast, which is included in the five-minute economic dispatch. Operationally, the hour ahead market and intrahour economic dispatch provide a more limited range of options for system operators. Specifically, the ability of system operators to commit generation in this time frame is very limited. Consequently, the need for accuracy in the hour ahead forecast is greater.

Hour-ahead wind forecasting, as one would expect, is significantly more accurate than day-ahead and longer-term forecasts. Relatively simple (persistence) forecasting typically produces MAE values of about 5% of plant rating[viii] looking a single hour ahead. For operations, "hour-ahead" actually means 2¼ hour-ahead, since the forecast must be performed and fed to system operations. In this section, the relative accuracy of these "hour-ahead" and day-ahead wind forecasting is examined. As in the previous section, the month of January 2001 is presented in detail.

Figure 3.14 shows the following three traces:

Forecast DA Wind – The wind power that would have been forecast a day-ahead at that time for the study wind generation scenario.

Forecast HA Wind – The wind power that would have been forecast an hour-ahead at that time for the study wind generation scenario.

Actual Wind – The wind power that would have been produced at that time for the study wind generation scenario.

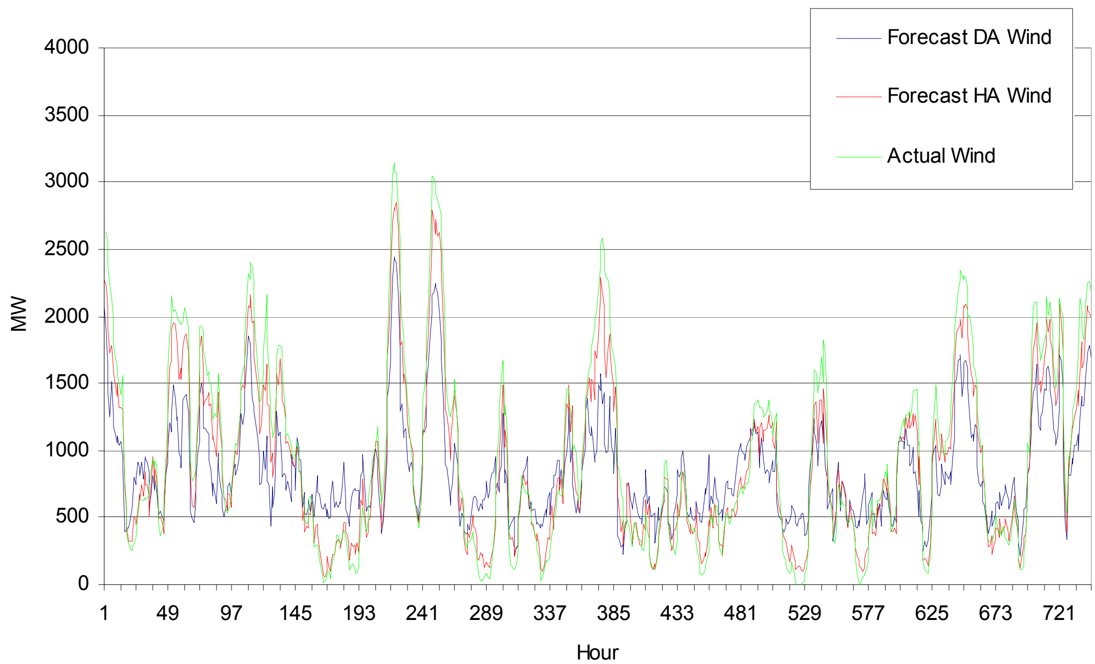

Figure 3.14. Day-Ahead and Hour-Ahead Wind Forecast and Actual Wind for January 2001

Figure 3.15 shows the error for the two forecasts, and Figure 3.16 shows the error duration curves for the same period. These figures show that the forecast accuracy improves considerably as the forecast horizon draws closer. The improvement can be observed quantitatively in the statistics for this month of data, which are shown in Table 3.5. Most of the hour-ahead error metrics summarized in the table drop by about 50% to 60% of their day-ahead values. For example, the mean absolute error (MAE) drops from 358 MW (10.84% of total wind rating) to 135 MW (4.10% of rating) - a 62% improvement. The system-wide hour-ahead MAE for the wind forecast ranges between 4.10% and 4.23%, which is consistent with the expectation of about 8-12% MAE on an individual plant basis (again, recalling that this is actually 2¼ hours ahead).

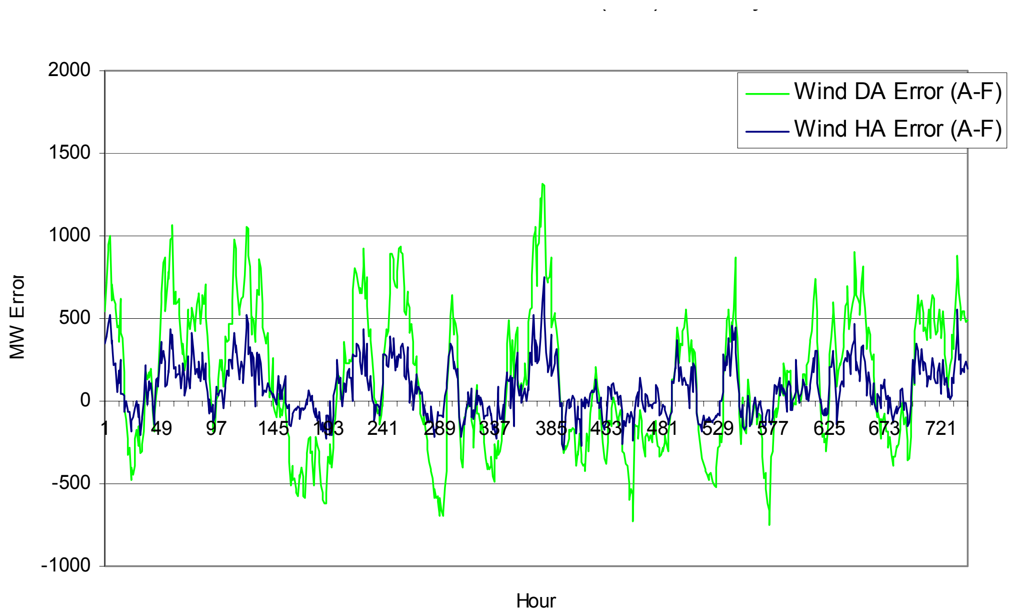

Figure 3.15 Day-Ahead and Hour-Ahead Wind Forecast Error for January 2001

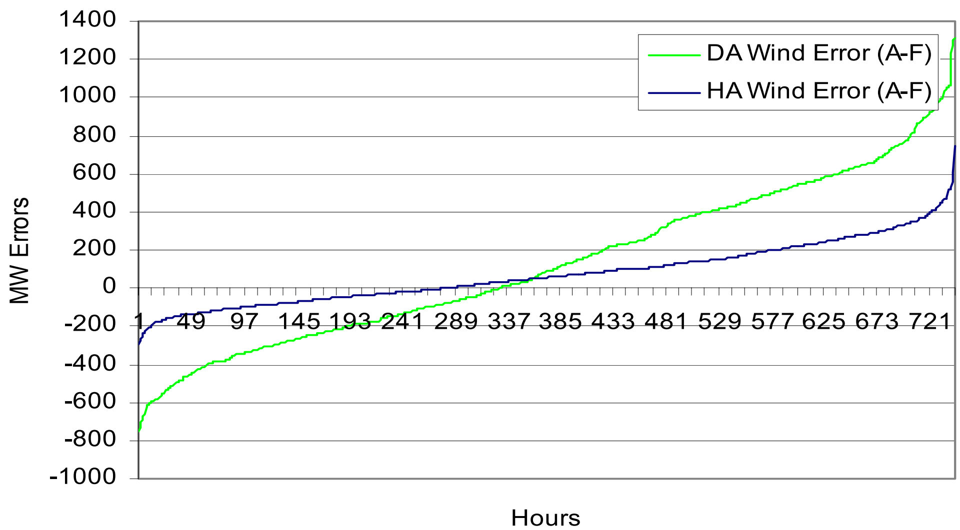

Figure 3.16 Day-Ahead and Hour-Ahead Wind Forecast Error Duration for January 2001

Table 3.5 Day-Ahead vs Hour-Ahead Wind Forecast Error Statistics for January 2001

2001 Jan Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	329	280
Hours Positive	415	464
Negative Energy Error (MWh)	-85,645	-23,098
Positive Energy Error(MWh)	180,573	77,491
Net Energy Error (MWh)	94,928	54,393
Worst Negative Error (MW)	-753	-295
Worst Positive Error (MW)	1,310	747
Peak (MW)	3,149	3,149
Energy (MWh)	723,591	723,591
Negative Energy Error(% of LE)	-0.62	-0.17
Positive Energy Error(% of LE)	1.32	0.56
MAE (MW)	358	135
MAE (% of Rating Wind)	10.84	4.10

The same analysis was performed for the other ten months of available data, with similar results. See appendix B.2 for detailed results by month. Figure 3.17 shows a comparison of the standard deviation of the day-ahead and hour-ahead wind forecasts. This figure shows a relatively consistent improvement of 50% to 60% from day-ahead to hour-ahead wind forecasting, that has a slight negative correlation to peak load. This negative correlation is due to lower average wind powers during months of peak load (as discussed in Section 7, *Effective Capacity*). Comparisons of hour-ahead and day-ahead error statistics for the three years of available data are shown in Table 3.6, Table 3.7, and Table 3.8.

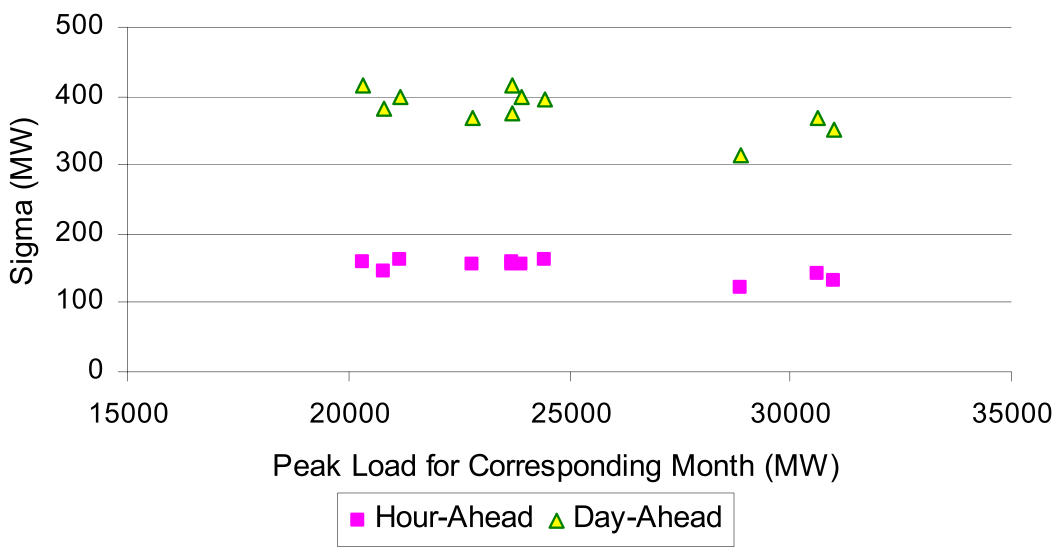

Figure 3.17 Day-Ahead vs Hour-Ahead Wind Forecast Error Sigma

Table 3.6 Statistics on Wind forecast Error for 2001

2001 Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	3,773	3,123
Hours Positive	4,987	5,637
Negative Energy Error (MWh)	-915,144	-244,659
Positive Energy Error(MWh)	2,112,992	948,017
Net Energy Error (MWh)	1,197,848	703,357
Worst Negative Error (MW)	-770	-367
Worst Positive Error (MW)	1,310	747
Peak (MW)	3,234	3,234
Min (MW)	0	0
Energy (MWh)	8,897,766	8,897,766
Negative Energy Error(% of LE)	-0.58	-0.16
Positive Energy Error(% of LE)	1.35	0.61
MAE (MW)	346	136
STD on Error (MW)	403	157
MAE (% of Rating Wind)	10.48	4.13

Table 3.7 Statistics on Wind Forecast Error 2002

2002 Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	3,263	2,684
Hours Positive	5,497	6,076
Negative Energy Error (MWh)	-757,377	-205,048
Positive Energy Error(MWh)	2,473,487	1,086,445
Net Energy Error (MWh)	1,716,110	881,398
Worst Negative Error (MW)	-798	-487
Worst Positive Error (MW)	1,266	676
Peak (MW)	3,234	3,234
Min (MW)	0	0
Energy (MWh)	9,873,862	9,873,862
Negative Energy Error(% of LE)	-0.48	-0.13
Positive Energy Error(% of LE)	1.56	0.68
MAE (MW)	369	147
STD on Error (MW)	407	158
MAE (% of Rating Wind)	11.18	4.47

Table 3.8 Statistics on Wind Forecast Error 2003

2003 Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	3,763	3,084
Hours Positive	4,997	5,676
Negative Energy Error (MWh)	-939,134	-249,494
Positive Energy Error(MWh)	2,101,866	966,351
Net Energy Error (MWh)	1,162,732	716,857
Worst Negative Error (MW)	-889	-425
Worst Positive Error (MW)	1,341	688
Peak (MW)	3,234	3,234
Min (MW)	0	0
Energy (MWh)	9,020,543	9,020,543
Negative Energy Error(% of LE)	-0.59	-0.16
Positive Energy Error(% of LE)	1.33	0.61
MAE (MW)	347	139
STD on Error (MW)	400	157
MAE (% of Rating Wind)	10.52	4.21

These three tables show that the levels of forecast error expected are fairly steady across the three years of data. The total energy involved in these hour ahead forecast errors is a fraction of a percent of the total load supplied in the NYSBPS. Over the three years of data, the hour-ahead negative energy error (i.e., over-prediction of wind power) ranged from 0.13% to 0.16% of total load energy served. The total hour-ahead positive energy error (i.e., under-prediction of wind power) ranged from 0.61% to 0.68% of total load energy served.

3.5 Centralized Versus Decentralized Forecasting

In both centralized and decentralized forecasting systems, forecasts will be made for individual wind projects. Furthermore, in both systems, the individual forecasts will be aggregated to regional and state totals, whether by the central provider or the ISO itself. Thus, both offer the benefit that forecast errors at one project will offset uncorrelated forecast errors at other projects, resulting in a smaller overall error for the entire system (as a fraction of the rated wind capacity).

The key difference between the two systems is that in a centralized system, a single forecasting entity would take responsibility for both generating the individual plant forecasts and aggregating them. This offers several potential benefits:

- A single entity will apply a consistent methodology and presumably achieve more consistent results across projects than a number of individual forecasting services. (On the other hand, if the entity uses an inferior method, forecasts for all plants would suffer.

Setting standards and providing incentives and disincentives to encourage the best possible forecasts can address this potential risk.)

- A single entity can more effectively identify approaching weather systems affecting all plants and warn the ISO of impending large shifts in wind generation; whereas individual forecasters might provide a number of different warnings at different times; which could produce confusion.
- A centralized entity can make use of data from each plant to improve the forecasts at other plants. For example, a change in output of one plant might signal a similar change in other plants downstream of the first. Individual forecasters would not have access to the data from other projects to make this possible.
- A centralized forecasting system allows for greater accountability. If the forecasts are not satisfactory, the ISO will know whom to hold responsible.
- A centralized system offers potentially large economies of scale, since many of the costs of forecasting for a given region are fixed.

3.6 Conclusions and Recommendations

3.6.1 Conclusions

Uncertainties introduced by errors in day-ahead forecasts for wind add slightly to those due to load forecasting, which are presently accommodated by system operations. The worst under-prediction of load, 2.4% of load energy served, occurs without wind generation. The worst over-prediction of load without wind generation is 2.8%, and 3.7% with wind generation.

Hour-ahead wind forecasts significantly reduce the uncertainties associated with the day-ahead forecasts. On a system-wide basis the wind forecast error (MAE and energy) is reduced by 50% to 60%.

Existing NYISO operating practices account for uncertainties in load forecast. The incremental uncertainties due to imperfect wind forecasts are not expected to impact the reliability of the NYSBPS.

These conclusions are based on the assumption of state-of-the-art wind forecasting, applied consistently to all wind resources in the state.

The operational impacts of these forecast uncertainties, and various methods to use forecasts in day-ahead operations, are further quantified in Section 4, *Hourly Production Simulation Analysis*.

3.6.2 Recommendations

The conclusion that uncertainties due to imperfect wind forecasts are not expected to impact the reliability of the NYSBPS is based the use of state-of-the-art forecasting. Development of statewide wind forecasting should be pursued.

Data collection from existing and new wind farms should proceed immediately, in order to provide input to, and increase the fidelity of, wind forecasts for when the system achieves higher levels of penetration.

Meteorological data collection and analysis from proposed and promising wind generation locations should proceed in order to aid and accelerate the development of high fidelity forecasting. Participation by NYS Transmission Owners, the NYISO and project developers and owners in recommended.

This page intentionally left blank.

4 Hourly Production Simulation Analysis

4.1 Introduction

This section examines the impact of the addition of significant amounts of wind generation on the overall operation of the NYISO system. The commitment and dispatch of the system are examined both with and without the addition of wind generation and with varying assumptions on the forecast accuracy. Key issues include the economic impact of the wind turbines on the system operation, the impact on transmission congestion, minimum load issues, emissions and what generation is displaced by technology, fuel type and location. The wind energy is assumed to be a "price taker" and is bid into the system at zero. This section only examines the operational impact and does not attempt to examine the overall economics of wind turbine generation.

4.1.1 Description of Cases

The basic data used for the analysis was from the NYPSC's MAPS database used for their RPS analysis in early 2004. The fuel prices were updated to be consistent with their fall 2004 studies. The power flow representation was updated with data provided by the NYISO in order to be consistent with the steady state and dynamic analysis performed in Section 6, *Operational Impacts*. Historical load shapes were used for both 2001 and 2002 along with wind data for the corresponding years. The year 2008 was selected for the analysis to reflect future system conditions. Peak loads and energies were adjusted to the 2008 forecasts provided by the NYISO. A summary of the wind farms by zone is shown in Section 1, *Introduction*. The existing generation and loads in PJMISO and ISONE were also fully modeled with Canada and other, more remote regions modeled more simply. A number of operating scenarios were examined. The cases, and their abbreviations used later in the summaries, are shown in Table 4.1 below.

Table 4.1 Description of Cases

Case	Abr.
no wind	no
actual wind for commitment, schedule wind after hydro	act
no commitment credit for wind	nc
forecast wind for commitment, schedule wind after hydro	fc
actual wind for commitment, schedule wind before hydro	act-prio
forecast wind for commitment, schedule wind before hydro	fc-prio

The base case, "no," assumed no new wind generation. For both the 2001 and 2002 scenarios wind generation data was provided based on actual meteorological conditions as well as based on the conditions predicted on the day ahead. This was to simulate the impact of predicting the wind generation in order to bid into the day ahead market. The comparisons of the day ahead, hour ahead and actual wind schedules is discussed in Section 3, *Forecast Accuracy*.

In the first wind case, "act," it was assumed that the forecast was 100% accurate. That is, the schedule used for the commitment of the thermal generation assumed perfect foreknowledge of the wind generation. The hydro schedules, however, were based on the load shapes only and were not adjusted based on the wind schedules.

The second wind case, "nc," assumed that there was no day ahead forecast available for the wind. The commitment schedule for the thermal generation was exactly the same as in the base case with no wind. Only the dispatch was modified to reflect the real time wind generation.

The third wind case, "fc," used the day ahead schedule for the wind to modify the commitment of the thermal generation, but used the actual wind schedule for the dispatch. As before, the hydro schedules were not affected by the presence of the wind.

The last two cases, "act-prio" and "fc-prio," were similar to the first and third wind cases in that either the actual or forecasted wind schedule could affect the commitment of the thermal generation. In addition, it was assumed that the forecasted wind schedule was known prior to the development of the pondage hydro schedule. In this way the hydro could be rescheduled to smooth out any "bumps" caused by variations in the wind generation output. The thermal generation was then scheduled for commitment after the wind and hydro.

4.2 Analysis of Results

There are lots of things that happen when new generation of any type is added to the system. This section will examine some of the key areas of energy displacement, emission reductions and impact on transmission congestion in addition to the overall economic impact of the wind additions. Just as important, it will examine how those impacts change based on the wind forecast, its accuracy, how it is used, and the historical wind and load patterns assumed.

4.2.1 Energy Displacement

Figure 4.1 and Figure 4.2 show the energy displaced in the system by the type of technology for the three primary scenarios using the 2001 and 2002 shapes, respectively. In both figures it can be seen that when no commitment credit is taken for the wind generation the bulk of the increases in displacements come from imports and new combined cycle units. This energy is from throughout the three ISO system specifically modeled (NY, PJM and NE) and the "imports" refer to other neighboring systems. When either the actual (no – act) or forecast (no – fc) shapes are reflected in the commitment of the thermal generation there is less impact on the more efficient new combined cycle units.

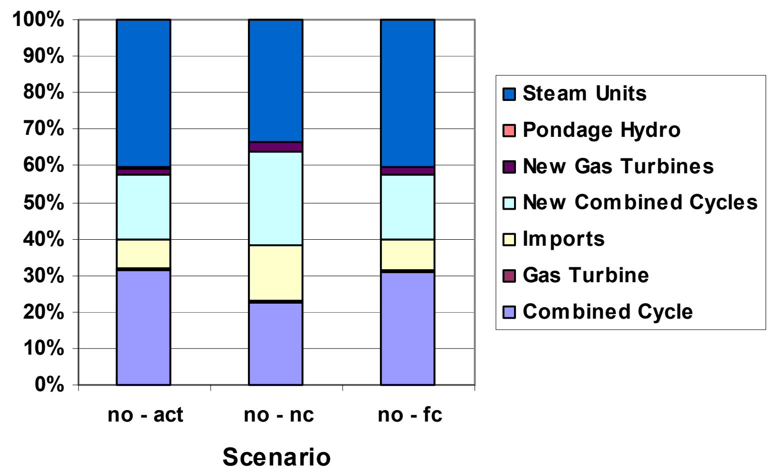

Figure 4.1 2001 Energy Displacement by Technology

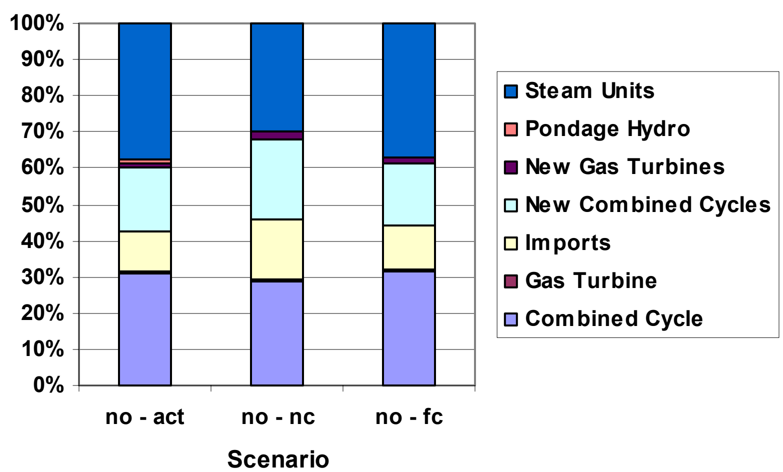

Figure 4.2 2002 Energy Displacement by Technology

Figure 4.3 and Figure 4.4 show a similar comparison by fuel type. When no commitment credit is taken for the wind generation a greater percentage of the displacements come from imports and coal. The coal-fired units are being backed down at night to make room for the wind energy. Recognizing the wind in the day ahead commitment allows the reduction in commitment of oil fired generation and more efficient use of the rest of the system. For the cases analyzed the coal displacement represents roughly .5% to 1% of the overall coal generation. The oil displacement, however, represents anywhere from 5% to 15% of the expected oil fired generation.

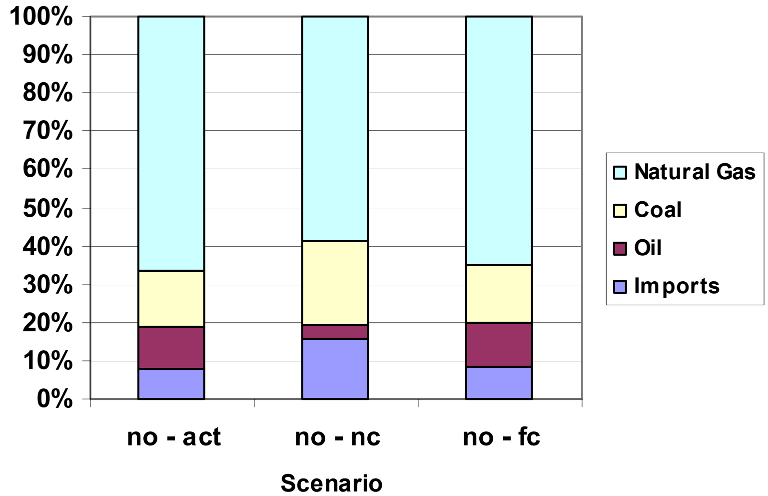

Figure 4.3 2001 Energy Displacement by Fuel

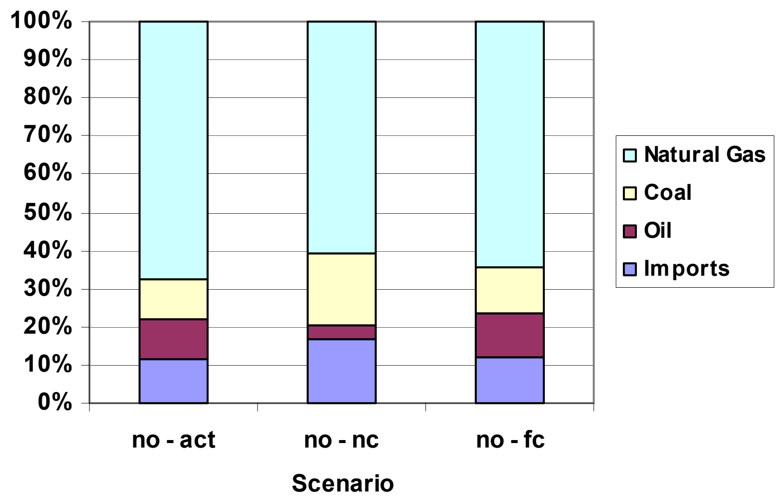

Figure 4.4 2002 Energy Displacement by Fuel

Figure 4.5 and Figure 4.6 show the wind generation and thermal energy displacement for each of the 11 zones in the NYISO. Although much of the wind generation occurs upstate, a significant portion of the energy displaced is downstate.

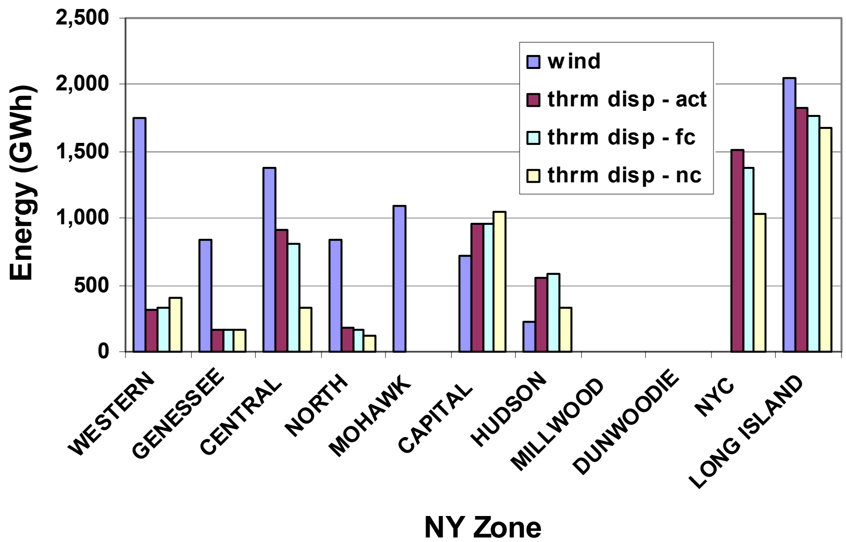

Figure 4.5 2001 Zonal Wind Generation and Displaced Thermal Generation

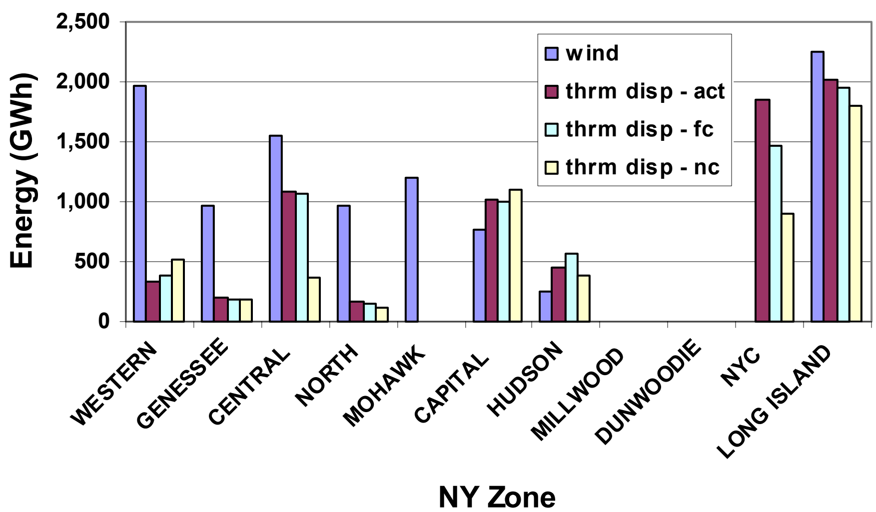

Figure 4.6 2002 Zonal Wind Generation and Displaced Thermal Generation

Figure 4.7 and Figure 4.8 show the regional and total displacement for the NYISO. Even though most of the wind generation occurs in the upstate areas more generation is displaced downstate than upstate. In fact, from the "total" columns it can be seen that the wind generation is significantly greater than the New York displacements for any of the scenarios. This displacement occurs outside of New York with reductions of imports to the state.

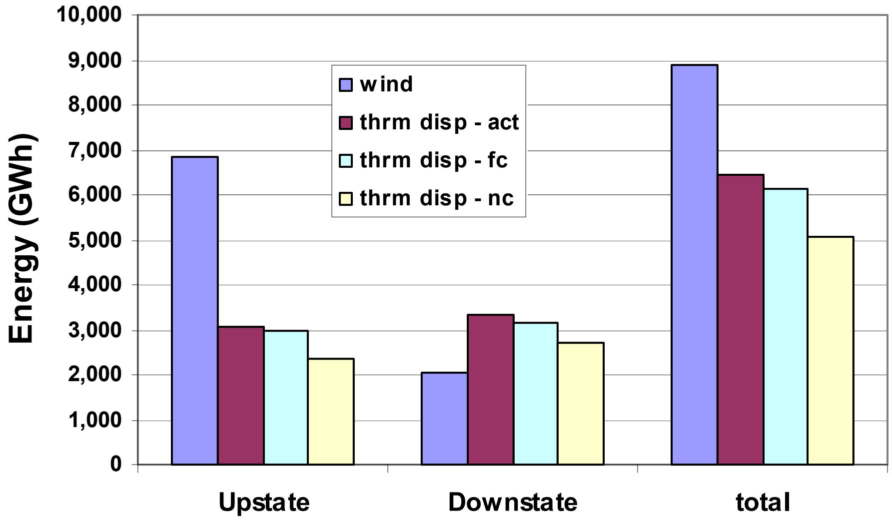

Figure 4.7 2001 Regional Energy Displacement

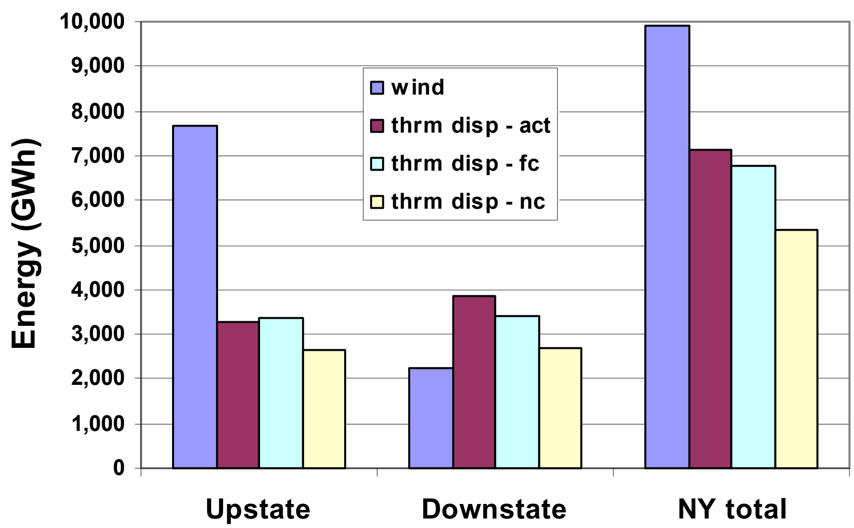

Figure 4.8 2002 Regional Energy Displacement

4.2.2 Emission Reductions

Another key area of interest is the impact on emissions. Figure 4.9 and Figure 4.10 show the impact on NOx and SOx using the 2001 and 2002 hourly data for load and wind. While there are significant reductions in all cases it is interesting to see that the "no commitment credit" actually had higher SOx reductions than the other scenarios. This is consistent with the fact that this scenario displaced more coal-fired generation, which have higher SOx emissions, since the commitment could not be adjusted to remove some of the more expensive oil fired generation. The emissions were included in the economic commitment and dispatch through use of a trading cost. The values used for the 2008 analysis were $237/ton for SOx and $2218/ton for NOx. While other emissions will also be effected only these two are traded and therefore only these two were tracked in the analysis.

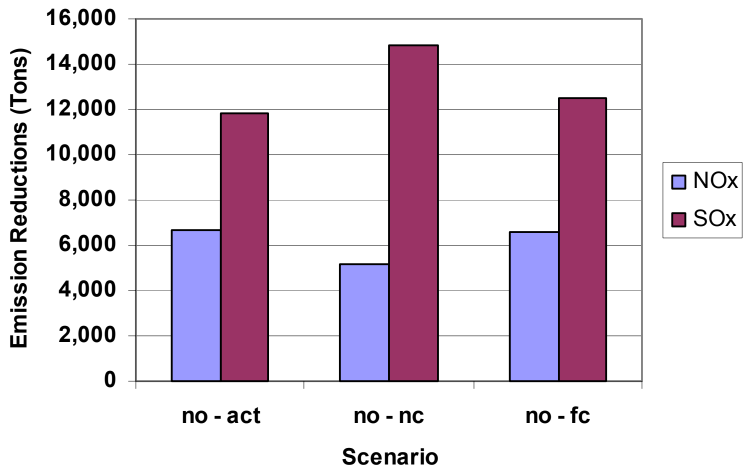

Figure 4.9 2001 Emission Reductions

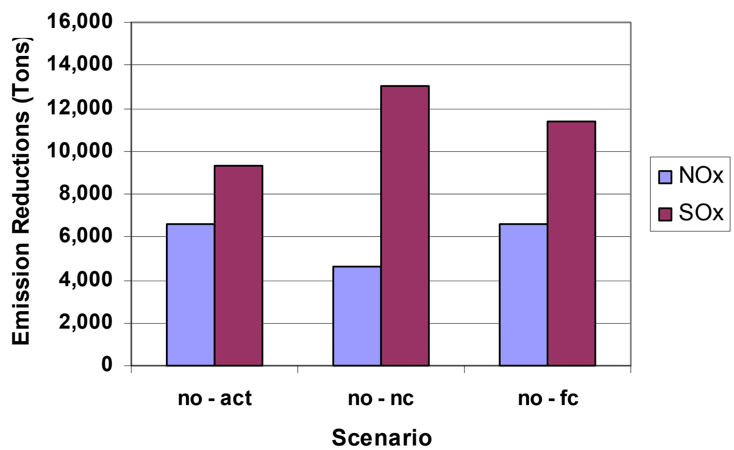

Figure 4.10 2002 Emission Reductions

4.2.3 Transmission Congestion

Because most of the wind generation is located in upstate New York there is an increase in the transmission flows from upstate to downstate. Figure 4.11 shows that the number of hours that the UPNY-SENY (upstate New York to Southeast New York) interface was limiting increased roughly 200 to 300 hours in the cases with the wind generation present.

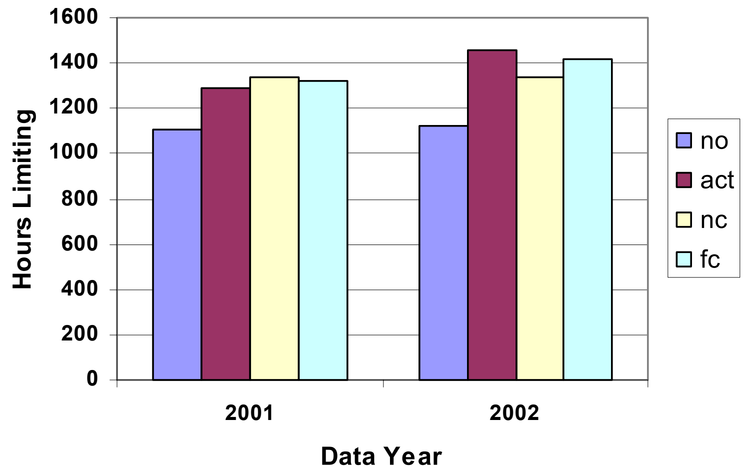

Figure 4.11 Hours Limiting on UPNY-SENY Interface

Although the flat section (limiting hours) is slightly extended, most of the increased flows occurred when the interface was not limiting, as shown for 2001 in Figure 4.12.

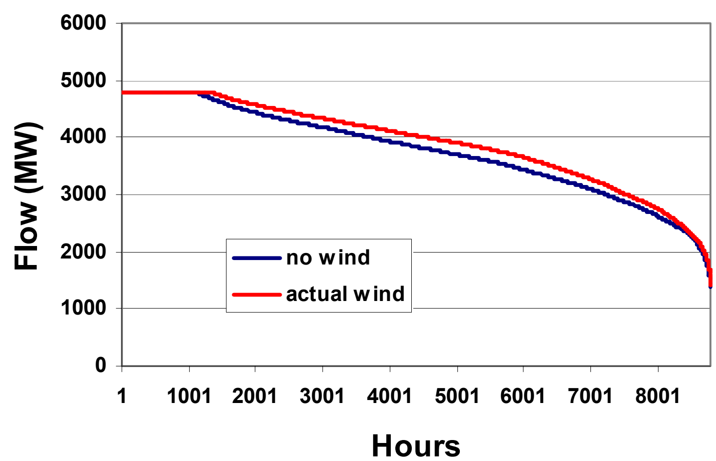

Figure 4.12 Duration Curve of Hourly Flows on UPNY-SENY Interface

The Total East Interface shows a similar increase in flows across the duration curve when wind generation is added to the system. There was roughly a 10% increase in energy flows across the Total East Interface for the scenarios with wind versus without. Figure 4.13 shows that while the interface is not limiting there is a significant increase in energy flows across the year. The addition of over 5000 MW of thermal generation east of the interface (and mostly downstate) in the 2004 through 2008 timeframe for both the "with" and "without" wind cases has produced an overall reduction in the Total East Interface flows from historical levels which were often limiting at 5250 MW.

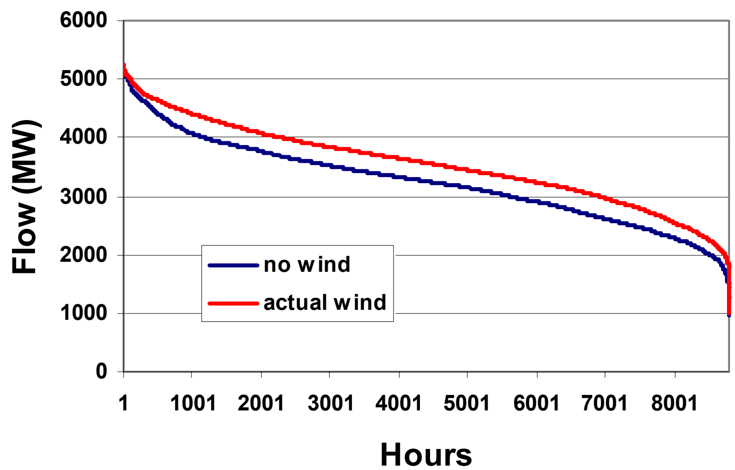

Figure 4.13 Duration Curve of Hourly Flows on Total East Interface

Another measure of congestion is the local spot price in an area. One concern was that excessive wind generation in the low load hours could cause "minimum load problems" whereby the thermal generation would be backed down to its minimum levels, the ties would be saturated and it would be necessary to "dump" excess energy. This is generally evidenced by zero, or even negative, spot prices. Figure 4.14 shows a duration curve of the hourly spot prices in the Genesee area for various scenarios.

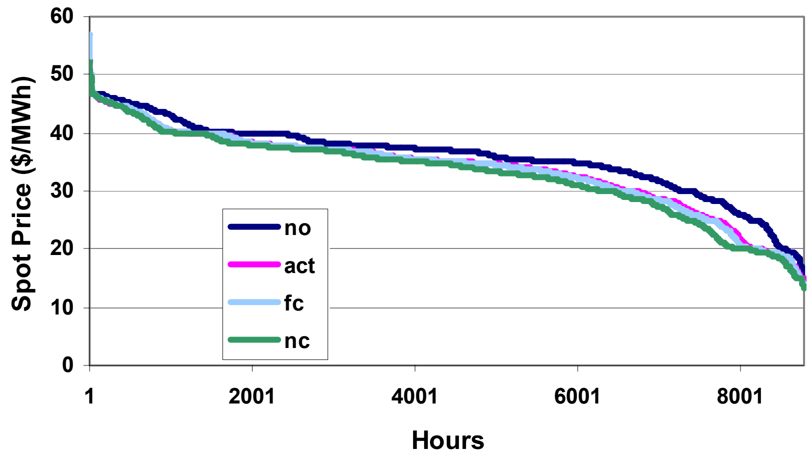

Figure 4.14 2001 Spot Price Duration Curve - Genesee Area

Although the spot prices are lower in all cases with wind added, as might be expected, there is no block of extremely low hours that would suggest minimum load concerns. New York's interchange with its neighbors was also examined. With no new wind energy in the system, New York was always a net importer of energy. This was still generally true even with the addition of the wind. In all cases with some level of forecasting available, the state was exporting less than 25 hours in the year. Only in the "no commitment credit" case did the simulation show the state as a net exporter for almost 100 hours of the year. Although some of the units with lower operating costs were still running above their minimum operating points, the assumption that neighboring systems could absorb the extra energy could be weak in those hours, particularly if the neighboring systems have also added significant amounts of wind generation. This again underscores the need for accurate forecasting in order to make best use of the wind resources and minimize any negative impacts on the system.

4.2.4 Economic Impact

Although the primary focus of this analysis was reliability and operational issues, the economic impact was also of some interest. Figure 4.15 and Figure 4.16 show various measures of the economic impact for the different scenarios under both the 2001 and 2002 data analysis. Because the 2002 wind shape produced more generation (9,900 GWH vs 8,900 GWH in 2001) the economic impacts tended to be slightly greater with that data. The overall results, however, were consistent between the two years. The 2001 results also included the two additional scenarios where the hydro was allowed to reschedule due to wind generation.

The figures examine the impact on total variable cost, generator revenue and load payments. The first set of columns show the reduction in the total variable cost of operating the system, including fuel cost, variable O&M, start-up costs and emission payments. These variable costs can be viewed as the actual cost savings because these represent the actual reductions in cost. This is opposed to the other columns, which are more "cost allocation" values based on the Locational Marginal Price (LMP) market.

The variations between the columns demonstrate the value of an accurate forecast for the commitment of the balance of the system. The "no commitment credit" case had a variable cost reduction of less than $40/MWh of wind generation while the others were around $50/MWh. Using the forecasted shapes versus the actual shapes produced only a slight reduction in the benefits, but this may be a reflection of the relatively high degree of accuracy in the forecasted shapes. Adjusting the hydro after forecasting the wind provided some slight additional benefits.

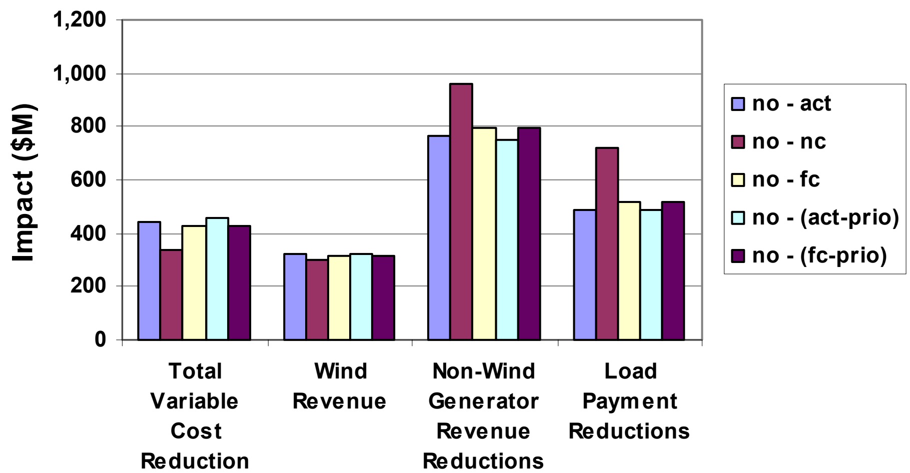

Figure 4.15 2001 Economic Impact

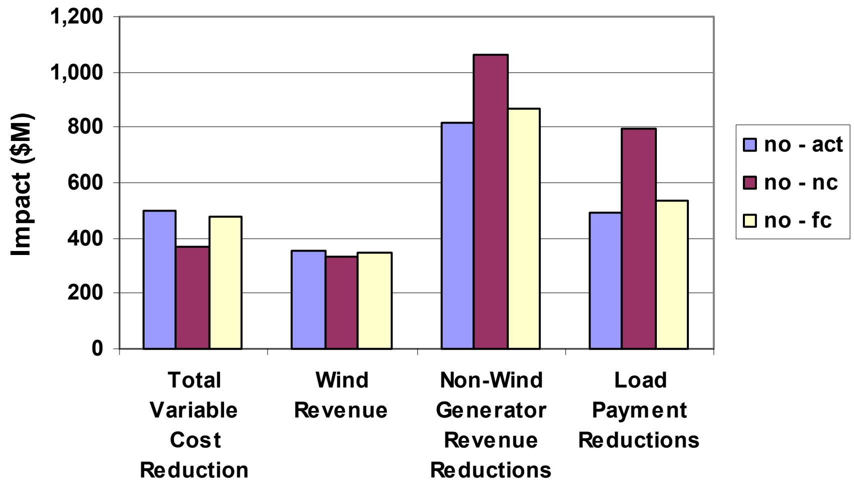

Figure 4.16 2002 Economic Impact

The second set of columns show the revenue generated by the wind plants. This revenue is calculated as the product of the generator output each hour and the corresponding Locational Marginal Price (LMP). Although there was some variation these averaged about $35/MWh for all of the cases.

The third set of columns shows the reduction in revenue for the non-wind generators. The non-wind generators take a double hit in that the wind generation not only displaces some of their energy but also reduces the value of the energy that they do produce. Note that this may be true for any new generation additions and is not limited to wind generation. Because the "nc" case did not allow any generation to be decommitted it tended to drive the spot prices lower and produce a significantly greater reduction in the non-wind generator revenues. These values represent about a 4% reduction in the overall non-wind generator revenue in the New York/New England/PJM territory being examined, and about an 8% reduction in just the New York non-wind generator revenue. This 8% was not distributed evenly, however. The analysis showed that the revenue for the residual oil fired generation would be reduced by 20% when comparing the "actual" versus "no wind" scenarios for the 2002 data. There is some concern that this type of impact on certain units may lead to increased retirements that could cause local operational concerns and/or decreased reliability. While valid concerns, these issues were not pursued further in this analysis.

The last set of columns show the reduction in load payments by the Load Serving Entities (LSEs). The load payments are the product of the hourly load and the corresponding LMP. These reductions in load payments are benefits that the consumers receive in addition to the increase in the amount of "green" energy being produced. This reduction in load payments would generally flow through as reduced energy payments for the consumer, thereby offsetting some of the costs of implementing a RPS program.

Figure 4.17 and Figure 4.18 show the zonal impact within the NYISO. In general, the spot price impact declines as you go west to east and north to south because you are moving farther away from the location of the wind farms. The exception is on Long Island, which has 600 MW of offshore wind generation in the study scenario, and typically high prices due to transmission congestion coming onto the island.

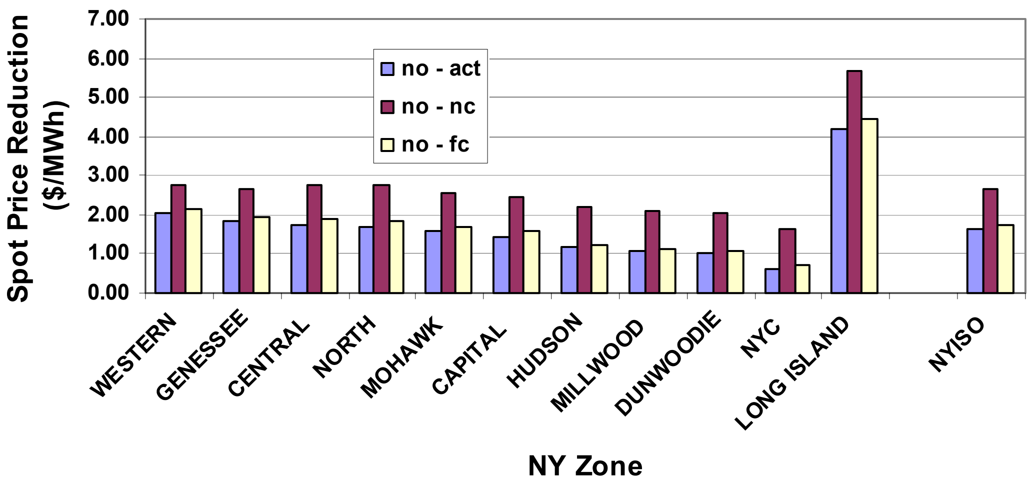

Figure 4.17 2001 Zonal Load Weighted Spot Price Reduction

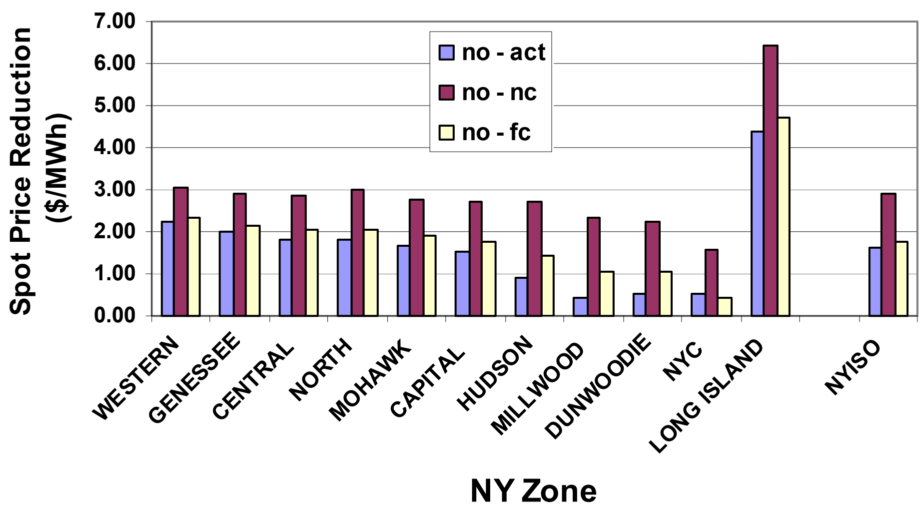

Figure 4.18 2002 Zonal Load Weighted Spot Price Reduction

4.3 Summary

Wind generation has the potential to significantly reduce the cost of system operation in New York while also reducing emissions and dependence on fossil fuels. The zonal spot prices would decrease by a few percent to as much as 10%. The SOx emissions in New York could reduce by 5% and the NOx emissions by 10% with the addition of 3,300 MW of wind generation.

While there was some increase in transmission congestion due to the fact that most of the proposed wind sites are in upstate and western New York, the bulk of the increased flows occurred during times that the interfaces were not fully loaded. In fact, despite the location of the wind farms more downstate thermal generation was displaced than upstate.

The ability to accurately forecast the wind generation for the day ahead market can greatly enhance its value. Roughly 25% of the system cost reductions between the “no wind” and “actual wind” cases results from the ability to predict the wind ahead of time and reflect its generation in the commitment of the rest of the system. The existing forecast accuracy seems to pick up 90% of that difference, but the remaining 10% is worth about $1.50/MWh of wind generation. Based on the data provided, day ahead forecast accuracy is fairly high when viewed across a projected 3,300 MW of wind capacity spread across the state. The accuracy for individual wind farms will not be as high and it may be appropriate for multiple wind farms to merge their forecasts on a zonal or regional basis.

5 Wind and Load Variability

The behavior of power systems is dynamic and driven by continuously changing conditions, to which the power system must continually adapt. The overview of system operation provided in Section 1.3, *Timescales for Power System Planning and Operations*, discussed the various time frames of operation at a high level.

In this section, a detailed statistical analysis of the variability of system loads and wind generation are presented. The results presented here complement the forecast error analysis presented in Section 3, *Forecast Accuracy*. Here, the issue is variation, not uncertainty. The power system must properly respond to these variations, regardless of how well anticipated or predicted they may be.

In the following subsections, progressively shorter periods of time and faster variations in load and wind power will be examined. The time frames correspond to the planning and operation processes outlined in Figure 1.2.

5.1 Annual and Seasonal Variability

There are differences in wind energy production between years. Figure 5.1 shows a duration curve for the three study years. The difference between the minimum and maximum production for the three years is about 1000 GWhr. Similarly, there is seasonal variability as well. To a large extent, these variations are primarily planning issues, rather than operational. Ultimately, issues of long-term variability of wind become significant in the context of economics of operation, capacity planning and to some extend maintenance outage scheduling. The seasonal and annual variability of expected wind production are shown in Figure 7.3. Since these longer-term issues are examined in detail in Section 4, *Hourly Production Simulation Analysis*, and Section 7, *Effective Capacity*, they will not be further discussed here.

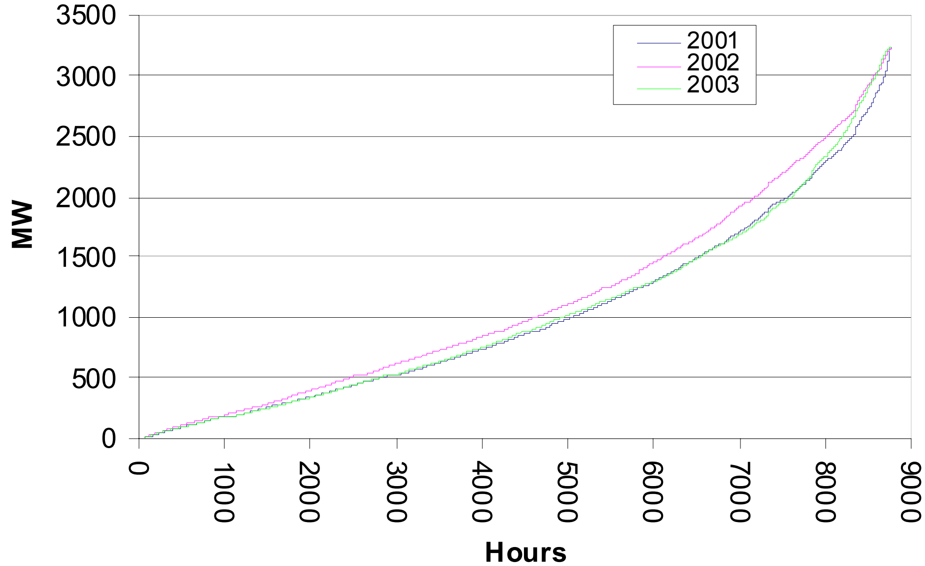

Figure 5.1 Annual Wind Production – Duration Curve

5.2 Hourly Variability

The hour-to-hour changes in system load and, in the future, wind generation, drive operations decisions, especially unit commitment and dispatch, that impact system reliability. In this section, hourly load and wind variability are examined separately and then in combination.

5.2.1 Daily Load Cycle

The daily load cycles within systems exhibit temporal and spatial characteristics that are relatively well understood. Initially in this section a detailed examination of a single day is provided, to give context to the statistics that are presented in the subsequent subsections.

5.2.1.1 Diurnal Characteristics

Figure 5.2 shows a statewide load profile for January 8, 2003 and August 1, 2003. This figure is based on six-second resolution, zonal load data provided by NYISO. These days were chosen as illustrative of winter and summer weekday load profiles. The winter load shape shows the characteristic rapid morning load rise and a second load rise to a daily maximum in the 16:00-19:00 time window of early evening. The summer load profile demonstrates the tendency to peak mid afternoon with later and less pronounced evening load rise. The load profile for each day in New York has qualitatively similar shape, but with different rates of load rise and fall, different magnitude and timing of maxima and minima. The load profiles are examined further in Section 7, *Effective Capacity*.

Figure 5.2 includes over 14,000 data points. Nevertheless, notice that it is relatively smooth, in the sense that fast variations (that make the trace slightly fuzzy) are minimal on this scale.

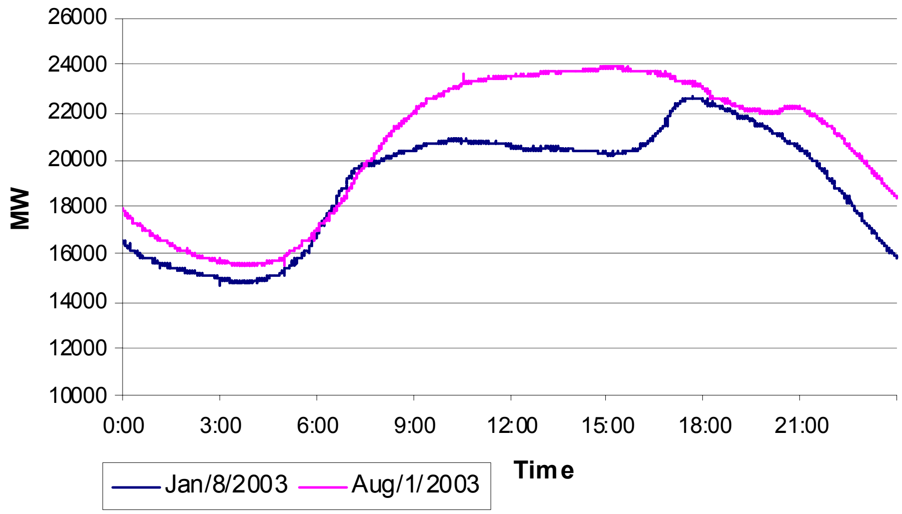

Figure 5.2 State-wide Daily Load Profile for January 8, 2003 and August 1, 2003

5.2.1.2 Geographic Characteristics

The NYSBPS system is segregated into three superzones, and 11 zones, as shown in Figure 1.1. Since Superzone A-E, which covers most of upstate (Zones A through E), is host to the majority of the study scenario wind generation, it is valuable to examine the load characteristics of that superzone separately from the entire state.

Figure 5.3 shows the daily load profiles for the Superzone A-E for January 8, 2003 and August 1, 2003. Notice that the load shapes are qualitatively similar to, but slightly less smooth than, the statewide curves in the previous figure. The daily maxima for the two days are approximately one third that for the entire state. In these figures, it is possible to see some of the finer, high frequency variation in the superzonal load. This faster variation will be examined further in subsequent subsections.

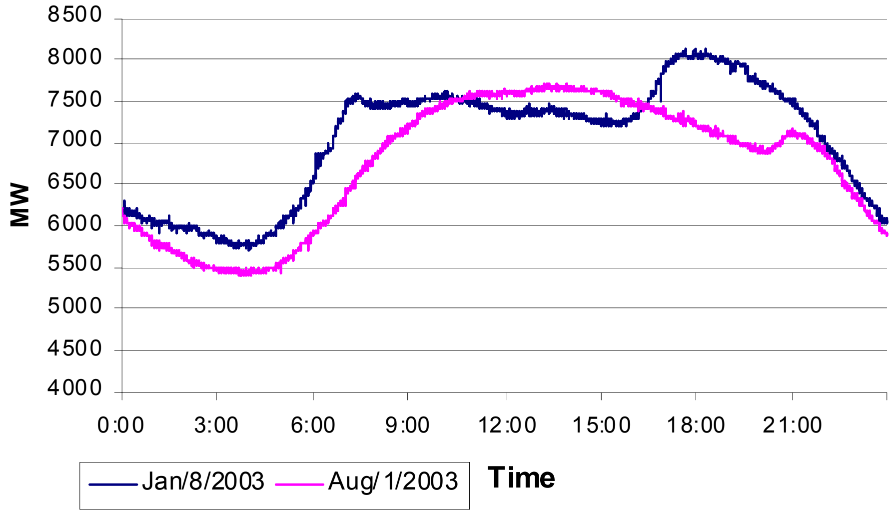

Figure 5.3 Daily Load Cycle for Superzone A-E for January 8, 2003 and August 1, 2003

Zone K on Long Island is host to the other large concentration of wind generation in the study scenario. The wind generation in Zone K is offshore. Figure 5.4 shows the load profile for Zone K. These curves exhibit the general shape of the statewide and superzonal load profiles. The relative maxima are on the order of 10-15% of the statewide load.

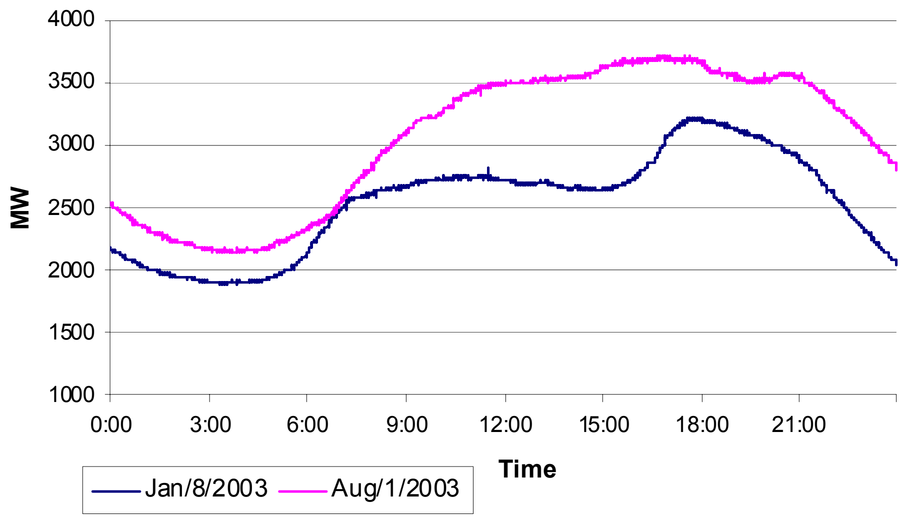

Figure 5.4 Daily Load Profiles for Zone K for January 8, 2003 and August 1, 2003

Each individual zone exhibits its own load profile, with each being similar but not identical to other zones.

5.2.2 Statistical Analysis of Hourly Load Variability

From an operations perspective, a primary concern is securely serving the load as it changes over the day. To the extent that the system has sufficient generating capacity, the major issue is change, rather than the absolute amount of wind power generated. The statistical nature of the hour-to-hour variation of load can be seen in Figure 5.5. In this histogram, the hour-to-hour changes in load power for the entire month (743 hours) are sorted into 200 MW bins. The distribution is roughly normal, with slightly more extremes on the positive (load rise) side.

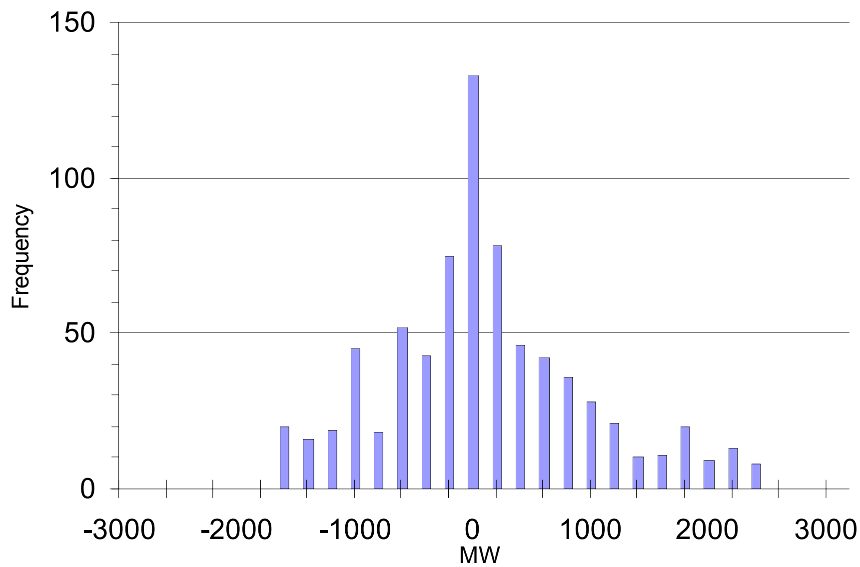

Figure 5.5 January 2001 Hourly Load Change

At the superzone level, the hourly variability histogram shown in Figure 5.6 is narrower; indicating that load rise within Superzone A-E is roughly in proportion to the magnitude of the load served.

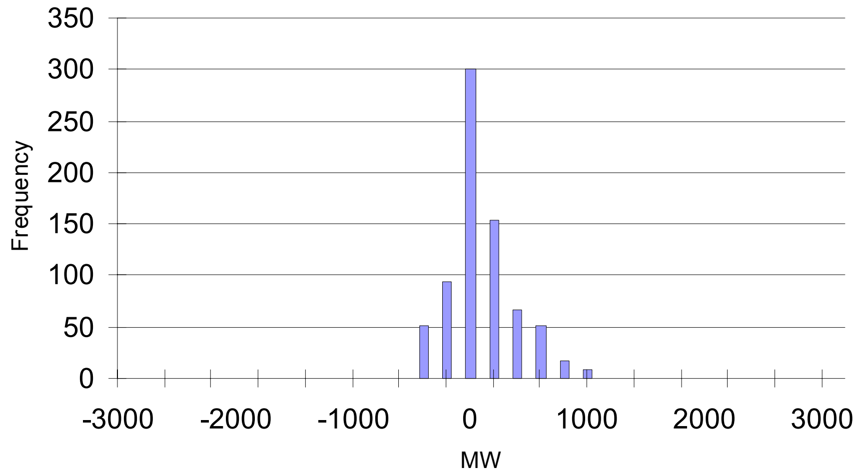

Figure 5.6 Hourly Load Variability in Superzone A-E for January 2001

5.2.3 Temporal Nature of Wind Penetration

The variation in wind production from day-to-day and hour-to-hour also exhibits characteristic diurnal patterns, although the daily patterns are not as orderly as those for load. The monthly pattern shown in Figure 3.4 is illustrative, and typical daily load shapes for the four seasons are shown in Figure 7.3. From an operations perspective, the presence of wind power, taken in isolation, is of little interest. The coincidence of wind generation with load, and the coincident change of load and wind are important, as their combination determines the rate of change that load-following generation must serve.

Penetration of wind generation is often measured on system-level as the ratio of the total installed wind generation to the system peak load. This measure was used in the Phase 1 Report of this project.[ix] However, in many regards, it is the instantaneous penetration that is of interest from an operations perspective. Specifically, conditions of high wind power production combined with relatively low system load can mean substantially larger penetrations than those suggested by the static system-level measure.

Figure 5.7 shows duration curves, for the month of January 2001, individually sorted, by state, Superzone A-E and Zone K. In each of the three traces, the hourly wind and load pairs for the corresponding area are used. So, for example, each point in the superzone penetration curve is that hour's wind generation in the superzone divided by that hour's load in the superzone. The figure shows that on a statewide basis, the study scenario, which has a nominal 10% penetration, only reaches or exceeds 10% for 100 hours in the month. However, the Superzone A-E and Zone K which host most of the wind generation exceed 10% about one-third of the time, and reach penetrations up to 35% on their local basis.

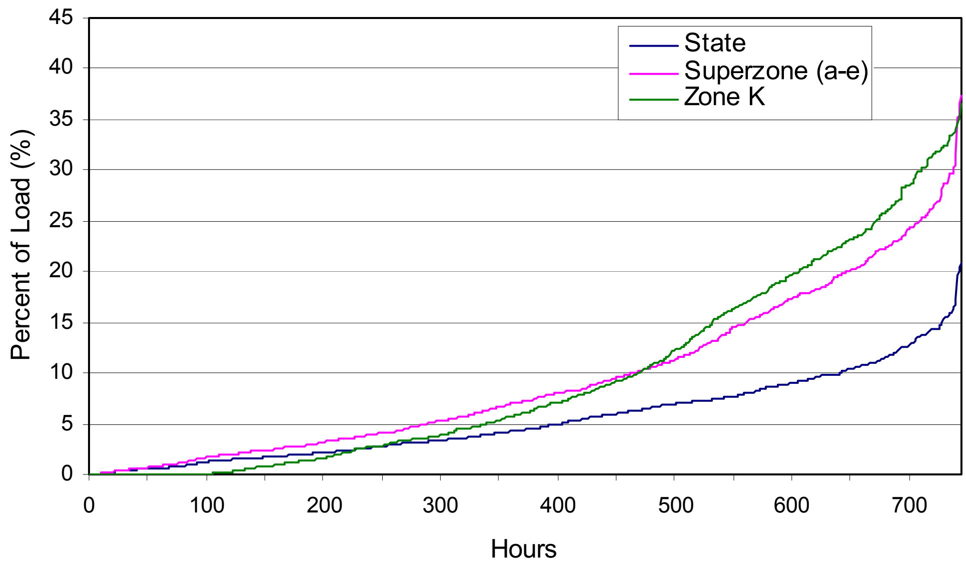

Figure 5.7 Range of Penetration based on actual wind for January 2001

Each month produces a distinct level of penetration, with some number of hours exceeding the nominal 10% penetration level. The hours of penetration in excess of 10% for the eleven months examined in Section 3, *Forecast Accuracy*, are shown in Figure 5.8. The seasonal variation in load and wind generation patterns are apparent in this plot, with fewer hours of penetration in excess of 10% showing up in the summer (August), and more hours during the higher wind months of October and January.

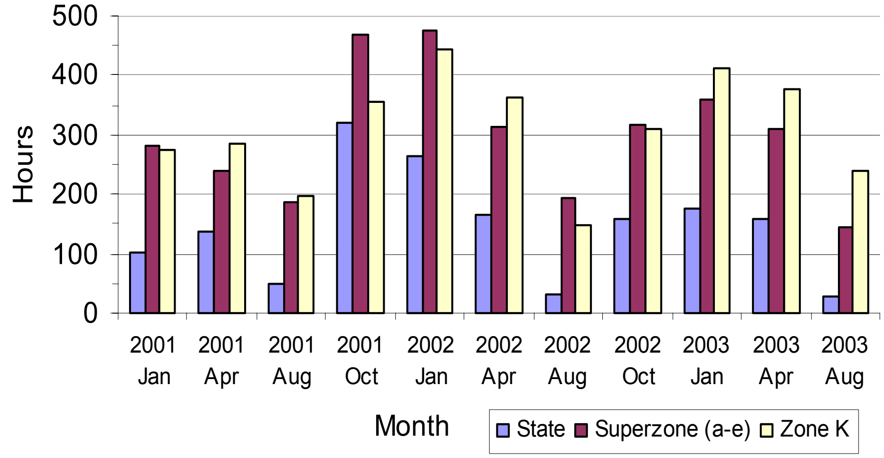

Figure 5.8 Hours Greater than 10% Penetration for Representative (Forecast) Months

5.2.4 Hourly Variability of Wind

The hour-to-hour variability of wind power is shown in Figure 5.9. The bin for this histogram is 100 MW (rather than 200 MW for the load variability histogram) since the magnitude of wind variability is less. This is the variability that corresponds to the actual wind power curve shown in Figure 3.4. There are less than 20 hours in this month when changes in statewide wind generation exceed 500 MW/hour.

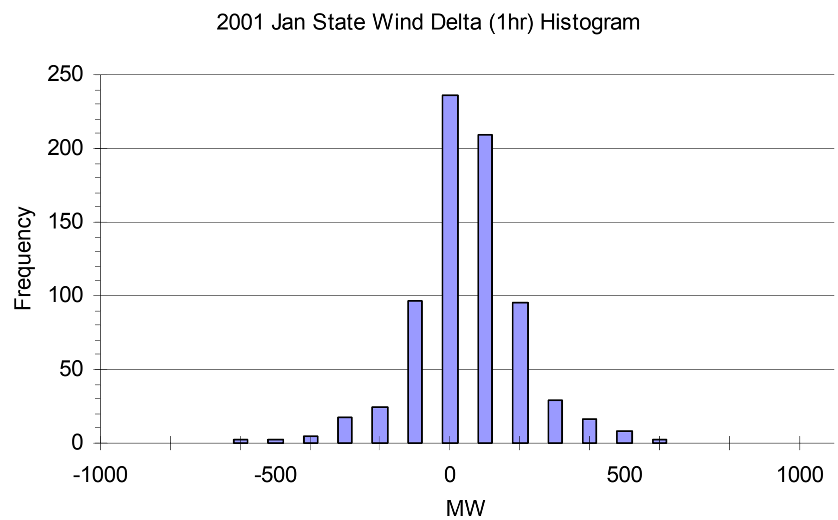

Figure 5.9 Hourly Variability of Statewide Wind Alone for January 2001

5.2.5 Combined Load and Wind Variability

Examination of the hour-to-hour variability of the system with and without wind provides the most insight. Figure 5.10 shows a comparison histogram of the two for January 2001. This figure shows the hour-to-hour changes that must be accommodated by the balance of dispatchable generation in New York State and power exchange with neighboring systems. This figure helps illustrate the fact that variability of wind generation has much the same characteristic as the stochastic variation of loads, for which the system is designed and operated.

Figure 5.10 shows the overall impact of wind generation at the statewide level. The standard deviation of the load only variability for January is 858 MW, increasing by 48 MW to 906 MW with wind. This means that within that month, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±2574 MW without wind, and ±2718 MW with wind. In this particular sample, the single largest positive load rise is 2288 MW without wind and 2459 MW with wind. This is consistent with the expectation based on 3σ. The largest single hourly load declines are 1787 MW and 2101 MW, respectively. Stated differently, these results show that the contribution to state-wide hour-to-hour variability of the 3300 MW of installed wind generation are expected to be within about ±150 MW.

Figure 5.11 shows the same information for Superzone A-E. As shown in Figure 5.7 and Figure 5.8, the penetration level within the superzone is significantly higher than that measured statewide. The impact on the hour-to-hour variability within the superzone is more noticeable, with a stronger trend towards larger load rise. The standard deviation of the superzone load only variability for January is 282 MW, increasing by 45 MW to 327 MW with wind. This means that within that month, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±846 MW without wind and ±981 MW with wind. In this particular sample, the single largest positive load rise is 871 MW without wind and 1042 MW with wind. This is consistent with the expectation based on 3σ. The largest single hourly load declines are 581 MW and 917 MW, without and with wind, respectively.

Figure 5.12 shows the same information from Zone K. The standard deviation of the Zone K load only variability for January is 144 MW, increasing by 15 MW to 159 MW with wind. This means that within that month, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±432 MW without wind, and ±477 MW with wind. This is supported by this sample, in which the single largest positive load rises were 399 MW and 507 MW, respectively, and the largest single hourly load declines were 318 MW and 401 MW, respectively.

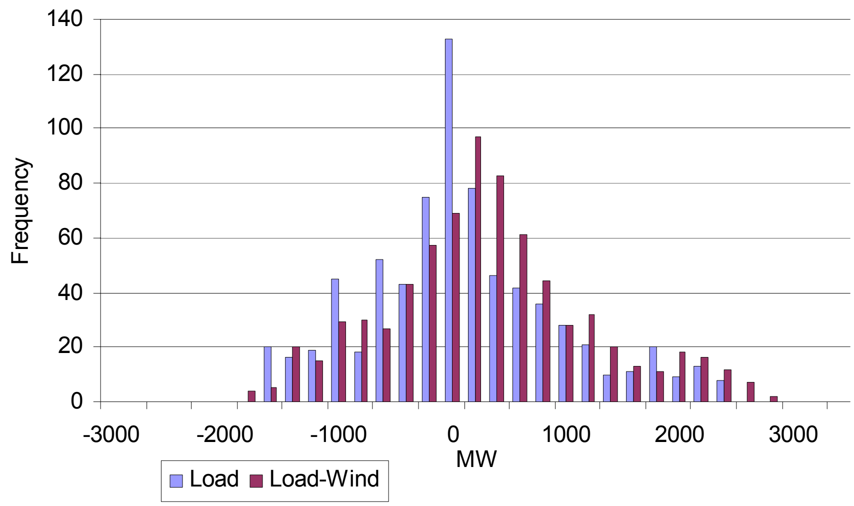

Figure 5.10 Statewide Hourly Variability for January 2001

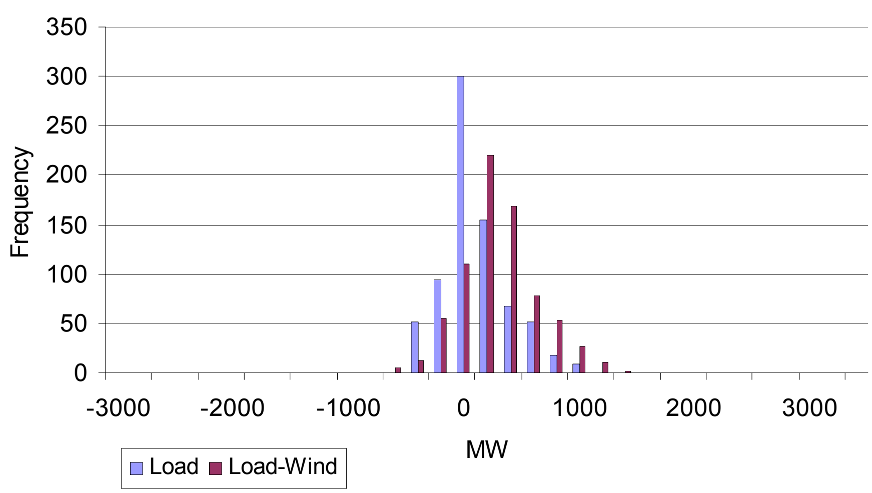

Figure 5.11 Superzone A-E Hourly Variability for January 2001

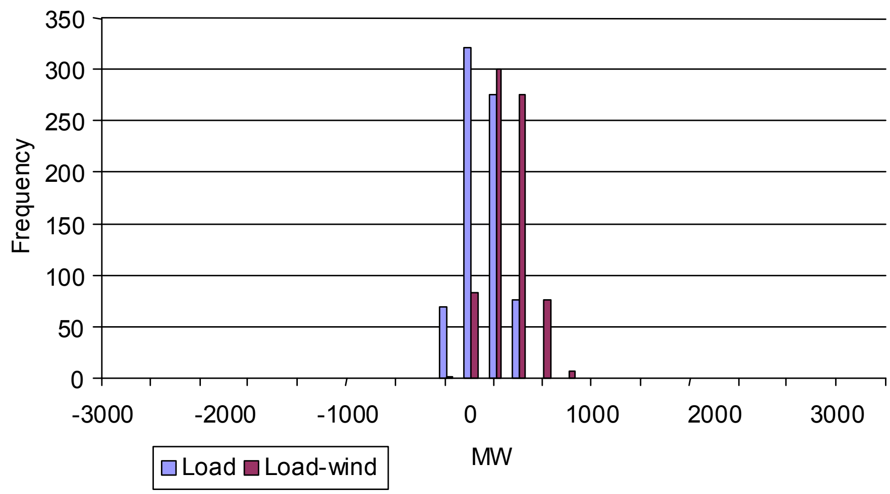

Figure 5.12 Zone K Hourly Variability for January 2001

5.2.5.1 Trends in Hourly Variability

The hour-to-hour variability shown in the figures for January 2001 is representative of that for each month. Figure 5.13 shows the standard deviation for each of the eleven months used for the forecasting analysis. For each month the plots show the standard deviation of hour-to-hour load variability with and without wind for the state, Superzone A-E and Zone K. Thus, for each month, there are six data points. They are plotted against the peak load for that month, for the respective geographical area. Notice that the standard deviation for all months and areas increases due to the addition of wind generation. All the standard deviations also increase with load. The difference between the with and without wind standard deviation in each area grouping is about the same, and not an obvious function of load level. In all months, the hourly increase in variability is small in MW terms. Specifically, the mean standard deviation of the statewide samples increases by 52 MW (6%), from 858 MW to 910 MW; the Superzone A-E samples increase by 45 MW (17%), from 268 MW to 313 MW; the Zone K samples increases by 22 MW (15%), from 149 MW to 171 MW. The production cost impact of these hourly changes was reflected in the analysis presented in Section 4, *Hourly Production Simulation Analysis*, and they are expected to be well within the dynamic capability of the system. This is examined further in Section 6, *Operation Impacts*.

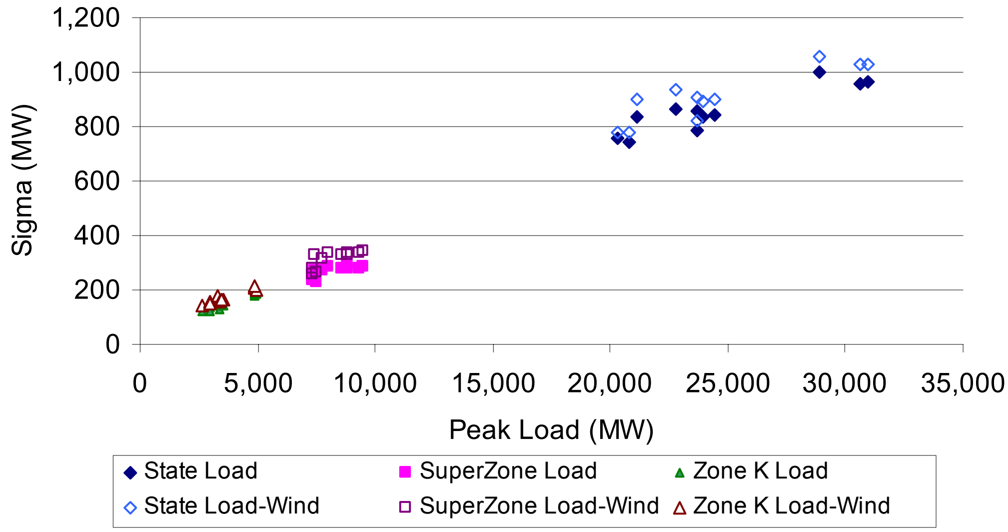

Figure 5.13 Standard Deviation of Hourly Load Variance (by month for 11 sample months)

Detailed statistics for each of the 11 months are included in Appendix C.

5.2.6 Time of Day Trends

Examination of daily and monthly variations tends to mask the impact of variations during periods that present the largest challenge to system operations: periods of rapid load rise. System operators give special attention to periods of peak demand and rapid rise in load. The summer morning load rise, especially during periods of sustained hot weather, presents one of the more severe tests to the system. The tendency of wind in New York State to decline during periods of rapid load rise prompts concern about the ability of the system to respond. Figure 5.14 shows the hour-to-hour variability for the summer morning load rise period. The data plotted is for all mornings during June through September for the three years of system data (2001-2003). There are three data points per day, the delta from 7:00 to 8:00 am, 8:00 to 9:00 am and 9:00 to 10:00 am. Unlike Figure 5.10, this distribution is not centered around zero. Essentially all values are positive, as would be expected for a load rise period. During this load rise period, it is not unusual for the state to experience load rise rates in excess of 2000 MW/hour. The figure shows that the tendency of wind generation to fall off during this period does indeed cause the distribution to trend towards higher rates of rise. In this sample of 1099 hours, 31% of the hours have rise rates ≥ 2000 MW/hr without wind, with the worst single hour rising 2575MW. With wind, this increases to 34% of hours with rise rates ≥ 2000 MW/hr, and a worst single hourly rise of 2756 MW.

Figure 5.15 shows a similar set of data corresponding to the winter evening load rise. Again, the presence of wind generation pushes the trend towards higher rates of load rise. The number of hours with rise rates ≥ 2000 MW/hr, increases from 2% to 4%, with the single worst hour changing from 2087 MW/hr to 2497 MW/hr. In each of these windows of time, system generation needs to be ramped up to follow this load rise. The presence of wind generation will increase this requirement. Overall, the impact on the load following requirement is relatively small compared to the existing requirement, which the New York State system presently meets. The performance of the system during such periods of high rate of load rise is examined further in Section 6, *Operational Impacts*. Statistics for the distributions shown in Figure 5.14 and Figure 5.15 are provided in Appendix C.

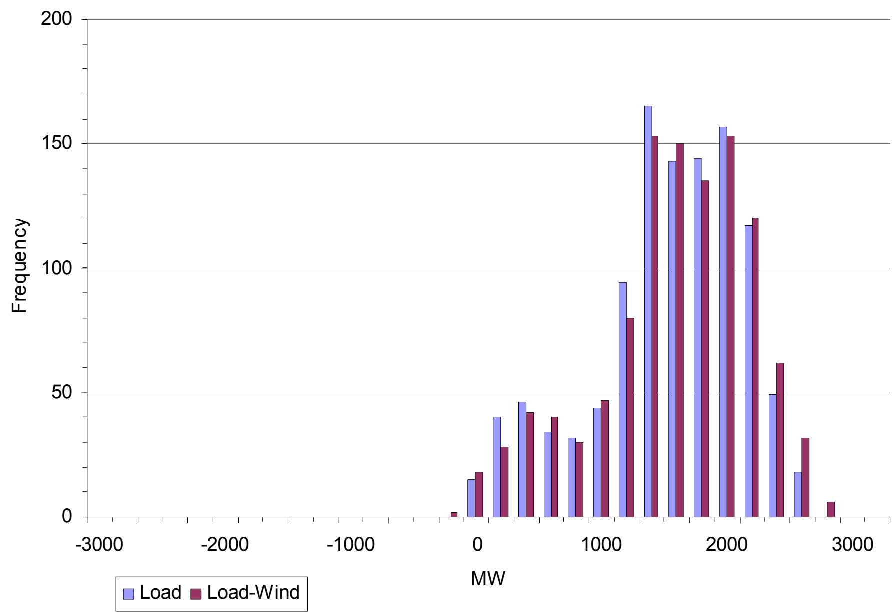

Figure 5.14 Summer Morning Load Rise - Hourly Variability

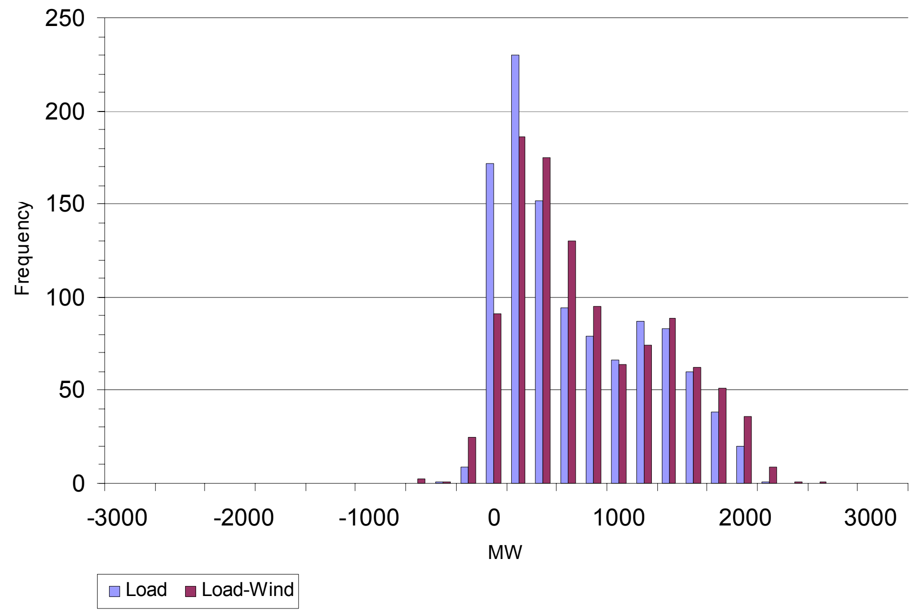

Figure 5.15 Winter Evening Load Rise - Hourly Variability

5.3 Five-Minute Variability

The analysis presented in the previous subsection shows that the hour-to-hour variability of the NYSBPS with wind generation is only slightly impacted. However, that data does not address system behavior within each individual hour. Within each hour, NYISO performs an economic dispatch at five-minute intervals, and adjusts the schedule on a subset of the generating plants within the state accordingly. Thus, system variation on these five-minute load-following intervals is critical to system operations.

In this section, a sample of three-hour windows of operation is analyzed. These three-hour sample windows are extracted from the six-second resolution load data provided by NYISO and the one-minute resolution wind data provided by AWS. Figure 5.16 shows a statewide histogram of five-minute load changes without and with wind for eighteen three-hour windows for which coincident wind and load data was available. The data includes samples from days in January, April and August. The statistical bins are 25 MW. Figure 5.17 shows the same samples for Superzone A-E and Figure 5.18 shows the distribution for Zone K.

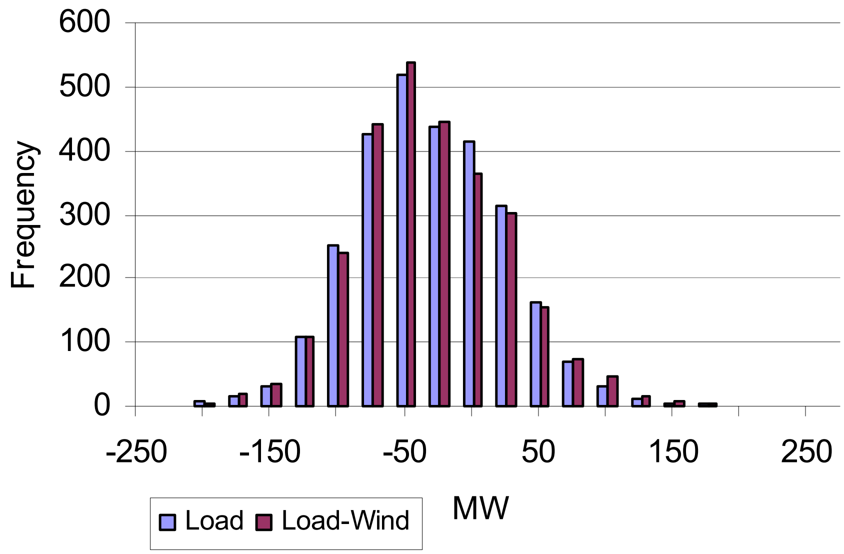

Figure 5.16 Five-minute Variability Statewide

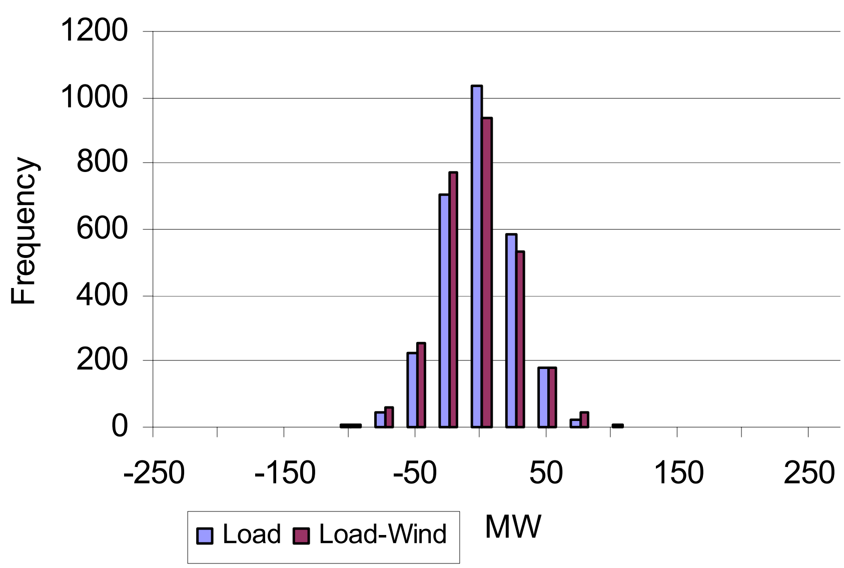

Figure 5.17 Five-minute Variability for Superzone A-E

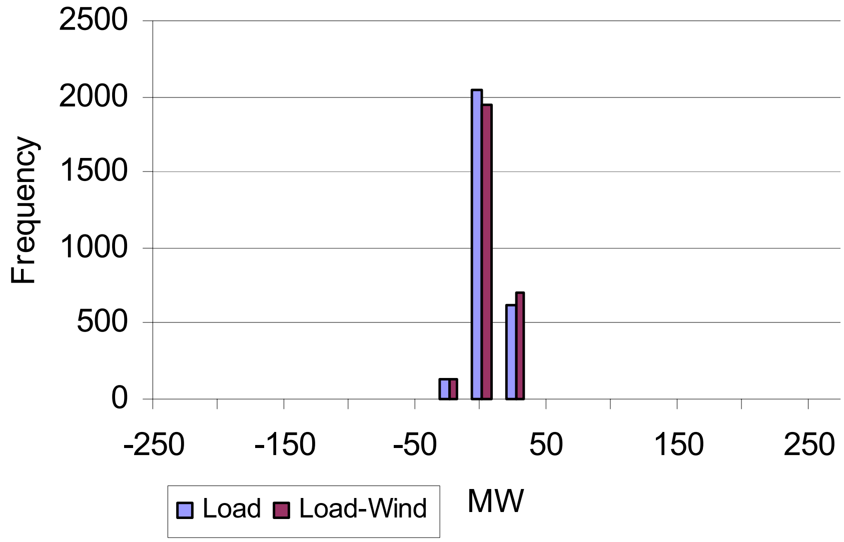

Figure 5.18 Five-minute Variability for Zone K

As expected, the geographic diversity of the wind sites causes the impact of wind generation on the five-minute variability to be quite small. Overall, there is a slight increase in the variability in each of the geographic areas. Specifically, the standard deviation of the statewide samples increases by 1.8 MW (3%), from 54.4 MW to 56.2 MW; the Superzone A-E samples increase by 2.2 MW (8%), from 27.5 MW to 29.7 MW; the Zone K samples increases by 0.5 MW (5%), from 11 MW to 11.5 MW. State-wide, the single largest positive load rises were 165 MW and 167 MW, respectively, without and with wind. For Superzone A-E, the largest single hourly load rises were 142 MW and 135 MW, respectively (i.e., lower with wind than without). And for Zone K, the largest single hourly load rises were 33 MW and 31 MW, respectively (also lower with wind than without). Appendix C includes similar plots for periods of high wind volatility and for selected high wind change events. Overall, the impact on five-minute variability is relatively small, and not expected to have substantial impact on load following. This is examined further in Section 6, *Operational Impacts*.

5.4 Six-Second Variability

Variation in system load during the intervals between five-minute economic dispatch adjustments are primarily handled by system regulation as directed through the automatic generation control (AGC).

The load characteristics shown in Figure 5.2 through Figure 5.4 for one day include information about these rapid variations in system load. However, the second-to-second variations in those figures are not of significant amplitude to be understandable compared to the larger and slower variations characteristic of the daily load cycle. Since the system is redispatched at five-minute intervals, variations within those intervals are indicative of the regulation requirement on the system.

Figure 5.19 shows the statewide load variation with respect to a five-minute running average for January 8, 2003. This plot effectively filters out the slower variations that are addressed by the load-following and day-ahead dispatch, leaving the fast fluctuations (across adjacent six-second periods) for which system regulation is needed. In this figure, variations on the order of +/- 50 MW can be seen at a more-or-less continuous level across the entire day. This variation is slowly biased up and down during the load cycle. For example, during periods of high rate of load rise (e.g., around 6:00 am and 5:00 pm), the curves tend to be above zero, and during load drop periods they tend to be negative.

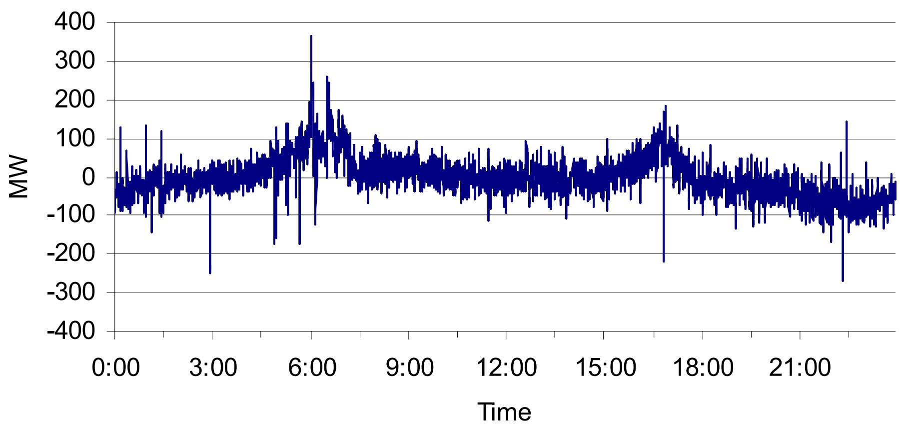

Figure 5.19 State-wide Load Variation Around Five-minute Running Average for January 8, 2003

Figure 5.20 shows the same information for Superzone A-E. It is interesting to note that the 'envelope' bounding most of the fluctuations is only slightly lower in magnitude (roughly +/- 30MW) than for the entire state, even though the total load in the superzone is about 1/3 that of the state as a whole. The trend continues to smaller and more granular areas of the system, as can be seen Figure 5.21, which shows the variation for Zone K only. This is an indication of the fact that these fast variations are relatively uncorrelated across the system. Thus, the larger the number and geographic diversity of the loads in the sample, the smaller the relative magnitude of the variation. All three of the figures show occasional spikes up or down. These can be due to major load start/stop events, minor system disturbances, or data anomalies. This small sample shows that occasional steps in load of hundreds of MW are part of normal system operations in New York State.

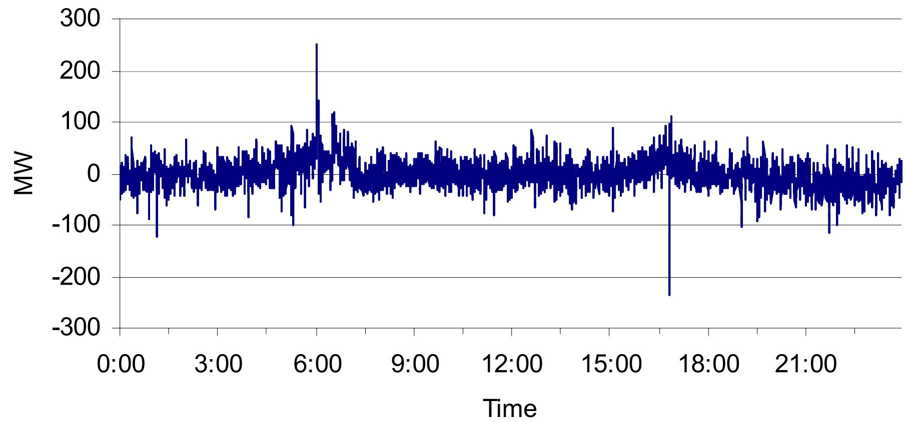

Figure 5.20 Superzone A-E Load Variation Around Five-minute Running Average for January 8, 2003

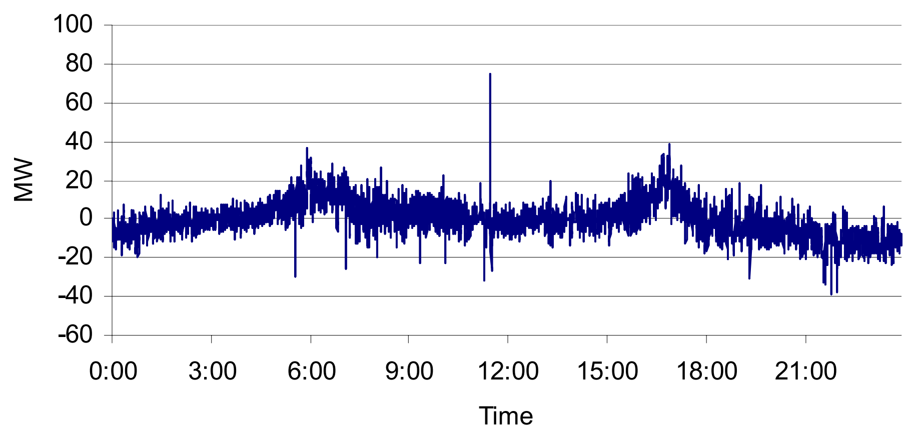

Figure 5.21 Zone K Load Variation Around Five-minute Running Average for January 8, 2003

The statistical characteristics of each zonal variation are shown in Figure 5.22. The data includes analysis of the two days shown in Figure 5.2 through Figure 5.4, and six other representative days (comprised of a weekend and week day from each season). Appendix C includes tables of all the statistical details of the fast load variability for these eight sample days. Notice that there is a moderate spread of standard deviations between zones and across individual days, but that overall the behavior is fairly consistent and shows no obvious correlation with season or day of the week. The total variability for Superzone A-E is much less than the arithmetic sum of the standard deviations from the constituent zones (A through E). This is even more obvious with the state total, and is confirmed with the other statistics included in Appendix C. The statewide standard deviations range in the neighborhood of 35 MW to 55 MW, statistically indicating that 99.7% of 6-second variation will be within three times this level.

The overall conclusion to be reached from this figure is that there is relatively little daily or seasonal variance in the required regulation for the state. There are occasional outliers observable at the zonal level. These occur during non-peak load periods, which tends to support the observation that regulation requirements are not strongly correlated to load level.

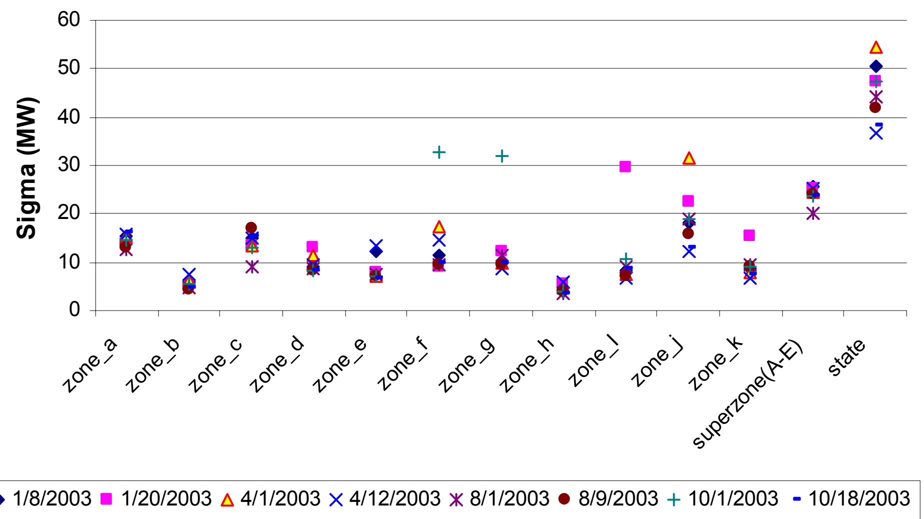

Figure 5.22 Six-second Variation by Zone, for Various Sample Days

5.4.1 AGC Performance

The automatic generation control, AGC, responds to departures from scheduled power interchange between New York State and the neighboring systems and deviations from nominal 60 Hz frequency. The AGC sends updated power setpoint commands to generating units on AGC at six-second intervals. The measure of deviation from schedule is area control error, (ACE), which has units of MW. There is a correlation between the amplitude of the ACE and the amount of regulation required to meet regulation performance objectives such as NERC Control Performance Standards, CPS1 and CPS2[x].

Figure 5.23 shows the New York State ACE for January 8, 2003. It is interesting to note that the amplitude of the high frequency variations in this trace is quite similar to that of the fast load variations shown in Figure 5.19. Given that the ACE has other, mostly slower variations also present, it is clear that there are other factors beyond load variation driving the ACE as well. These are probably related to generation ramping and changes in interchange with the neighboring systems.

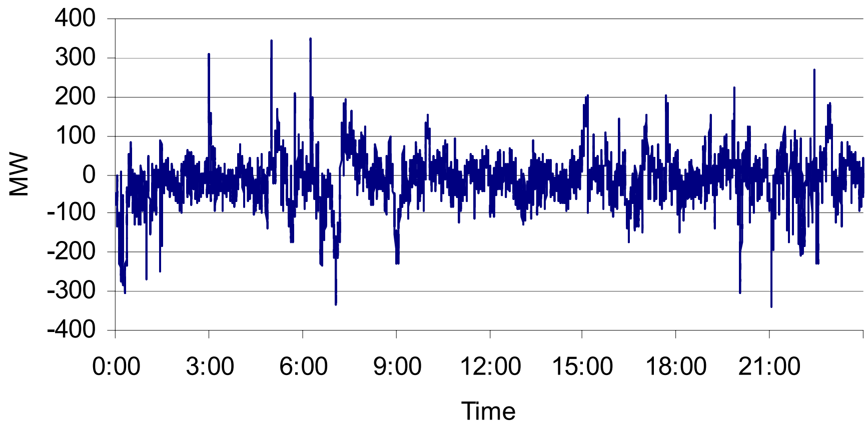

Figure 5.23 NYISO ACE for January 8, 2003

A histogram of the same day's ACE is shown in Figure 5.24. The distribution uses 25 MW statistical bins, with most values of ACE falling in the range of +/- 75MW. The standard deviation for this distribution is 67 MW.

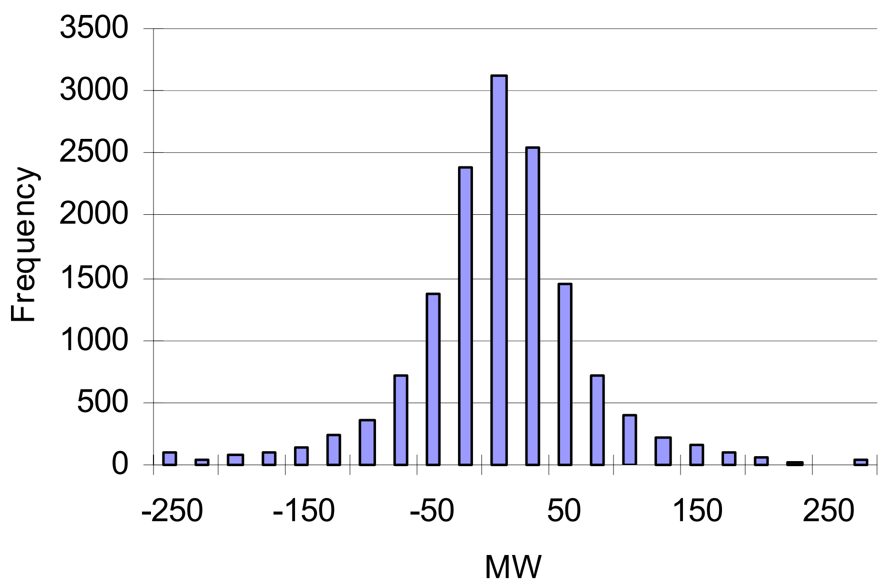

Figure 5.24 Histogram of ACE values for January 8, 2003

The variation in ACE is fairly uniform over the day, with slightly higher values observed during periods of maximum load rise and fall, as expected. The behavior of ACE does not change substantially across seasons or day of the week, as is shown in Figure 5.25.

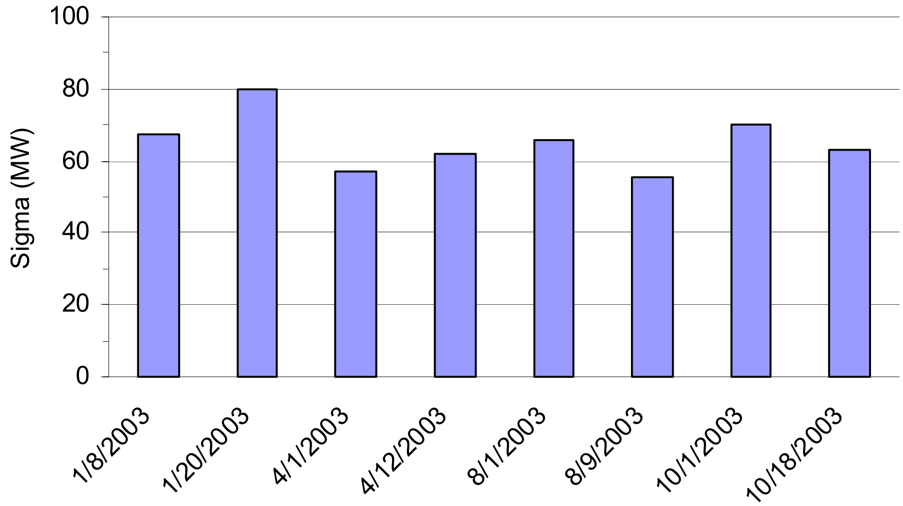

Figure 5.25 Distribution of ACE Standard Deviation

Table 5.1 shows a complete summary of the statistics on ACE for the eight representative days. The figure and table shows that the standard deviation on ACE is generally in the neighborhood of 75MW. Since the system needs to be operated so that ACE can be periodically driven through zero, there must be sufficient regulation power available from generation under AGC to cancel out ACE. Statistically (as noted above), three standard deviations will cover roughly 99.7% of events. New York State operating practice is to retain 225 to 275 MW of regulation power.[xi] This seems consistent with an ACE standard deviation on the order of 50 to 80 MW. This is also consistent with a load deviation (from Figure 5.22), which is in the neighborhood of 35 to 55 MW.

Table 5.1. ACE Statistics from Eight Representative Days

	8-Jan	20-Jan	1-Apr	12-Apr	1-Aug	9-Aug	1-Oct	18-Oct
00:05 - 23:59	ACE	ACE	ACE	ACE	ACE	ACE	ACE	ACE
Mean	-13.38	-38.60	-6.98	-2.82	-11.69	-6.43	-1.42	-5.23
Standard Error	0.56	0.67	0.48	0.52	0.55	0.46	0.59	0.53
Median	-11.67	-32.00	-12.17	-4.00	-9.33	-4.00	2.17	-4.50
Mode	-7.00	-70.00	5.00	0.00	9.00	23.00	2.00	-23.00
Standard Deviation	67.46	79.98	57.31	62.20	65.93	55.49	70.08	63.05
Sample Variance	4550.83	6396.63	3283.97	3868.25	4347.42	3079.58	4910.85	3975.68
Kurtosis	3.57	2.84	4.49	0.95	3.36	1.76	1.78	1.35
Skew ness	-0.26	-0.69	1.20	0.06	-0.31	-0.60	-0.37	0.12
Range	691.40	859.00	612.83	620.20	650.17	415.33	762.58	592.00
Minimum	-342.40	-504.00	-258.33	-321.00	-306.67	-252.33	-373.33	-292.50
Maximum	349.00	355.00	354.50	299.20	343.50	163.00	389.25	299.50
Sum	-191939.81	-553863.78	-100102.08	-40481.81	-167723.98	-92304.18	-20391.02	-75078.70
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

5.4.2 One-Second Wind Variability

The variability of wind power in the one-second time frame is statistically uncorrelated between sites[xii]. Six one-second resolution wind data sets were analyzed for their second-to-second variability. Figure 5.26 shows the standard deviation of second-to-second changes for each of the scenario wind sites, for each of the six 10-minute wind samples. In the figure, each color/shape corresponds to one of the samples for all of the sites. The individual sites are plotted against the project rating on the x-axis. Notice, that for any given sample, there is a wide range of variability, even between projects of similar size. This would be expected for a short sample like this. Notice also that variability, while increasing with project size, does not increase in proportion to project size. This is again because the spatial diversity within a large farm is quite important in this time frame, and results in significant smoothing for large projects. The largest site (600 MW) is offshore, and so also benefits from somewhat steadier wind than on-shore sites. The heavy brown dots are for the wind sample used in stability simulations presented in Section 6.2, *Stability Analysis*. In additional to these spatial diversity benefits, the second-to-second variability from individual wind turbines is limited by their physical characteristics. Wind turbines have significant inertia, which limits the rate at which power output can change. Further, the electrical and control characteristics of wind turbine generators have a significant impact on the relationship between wind speed fluctuation and electric power output.

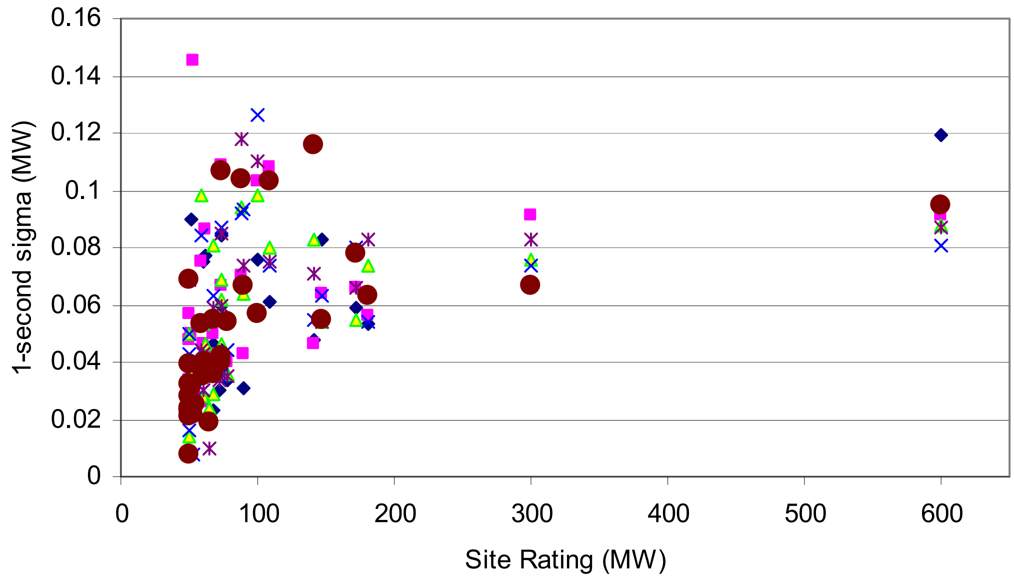

Figure 5.26 Variability Statistics (One-second) for Samples

5.4.2.1 One-Second Wind Variability Of One Wind Farm

The second-to-second variation in output of a specific wind farm is a highly localized phenomena. Historical measurements at other locations and meso-scale meteorology can provide some level of insight into the expected behavior of a farm. In this section, detailed statistical analyses of an operating farm are presented. The data is one-second resolution data for an approximately 100 MW farm in Iowa[xiii]. The total farm output for the month is shown in Figure 5.27. There are about 2.7 million data samples plotted in this figure, which clearly shows substantial variation in output over the month. This output looks highly variable, but recall that this is 744 hours (31 days). In this context, we are concerned with second-to-second variations within 10-minute windows.

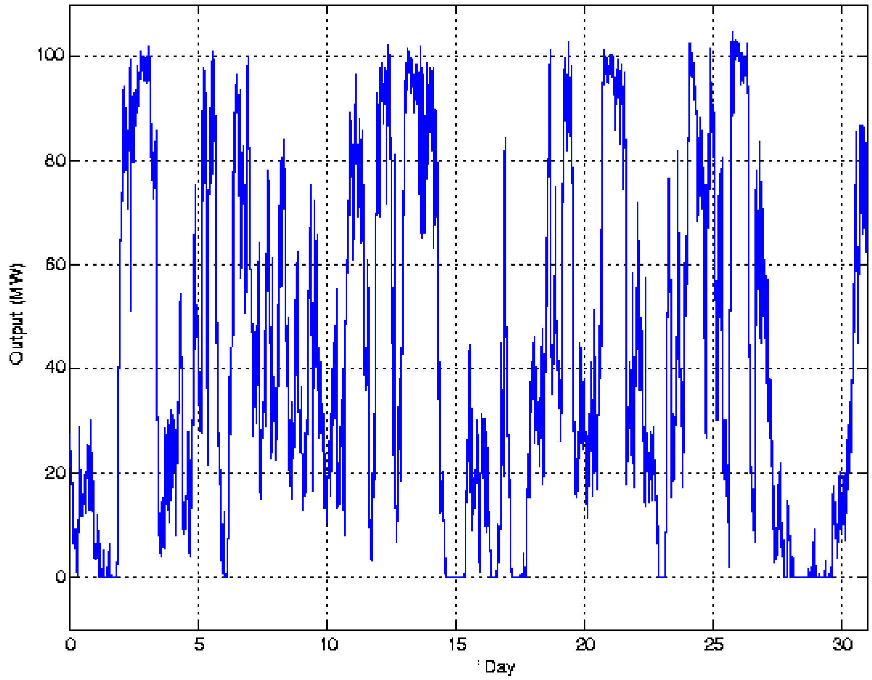

Figure 5.27 One Month of One-second Resolution Data from Operating Wind Farm

Figure 5.28 shows the second-to-second change for the output plotted in Figure 5.27. Notice that at no time in the month did a change in excess of 1 MW, roughly 1%, occur in a second. Most changes are much smaller. In terms of system stability, a 1% step change is normally trivial.

It is possible for individual wind turbines to trip within a farm, due to local equipment problems or due to high winds. In such cases, a step decrease of up to the rating of a single wind turbine is possible, though no such event is identifiable in this sample. In general, tripping due to high wind will occur one wind turbine at a time over a farm. High wind speed cutout was considered in the development of the statewide wind scenarios, but is not a major contributor to the largest system changes in any of the operational time frames.

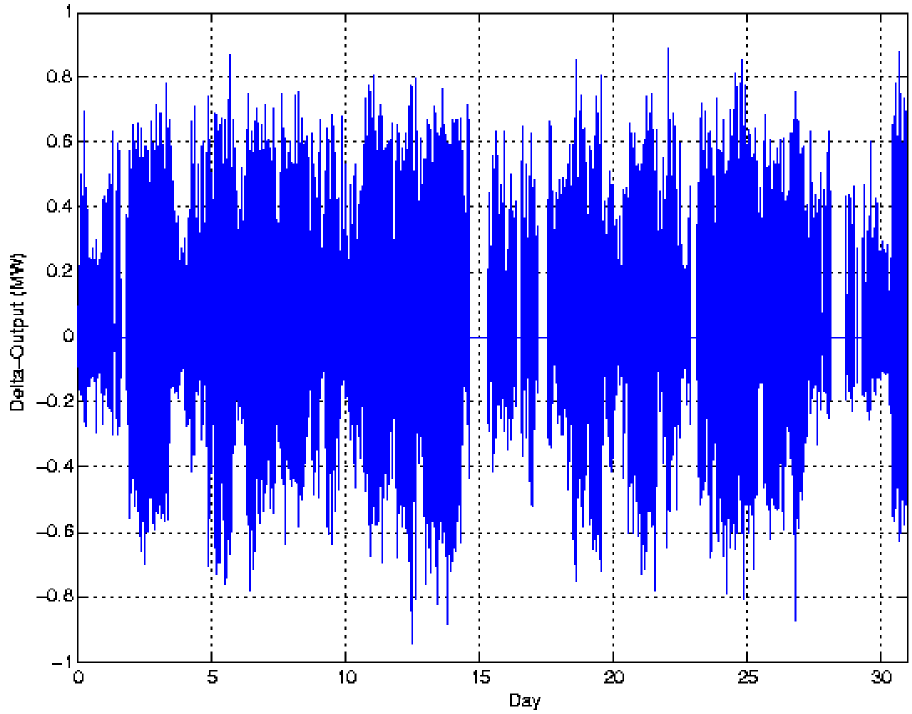

Figure 5.28 Second-to-second Change for One Month

The standard deviation of this entire sample is 0.0919 MW or about 0.1% of the farm rating. However, for any selected 10-minute sample, the standard deviation may be greater or less than this. Figure 5.29 shows a rolling 10-minute window of the standard deviation of the variation from Figure 5.28. There are very brief windows when the standard deviation reaches as high as 0.2 MW and periods when the variation is zero (corresponding to periods of no wind). The trend is around 0.1%, as expected. A histogram of these standard deviations is shown in Figure 5.30. The annotation on the figure points out the range of deviations for the 10-minute samples used for this study from Figure 5.26. The range of variance for the sample used to test New York State regulation in Section 6, *Operational Impacts*, is consistent with these field measurements.

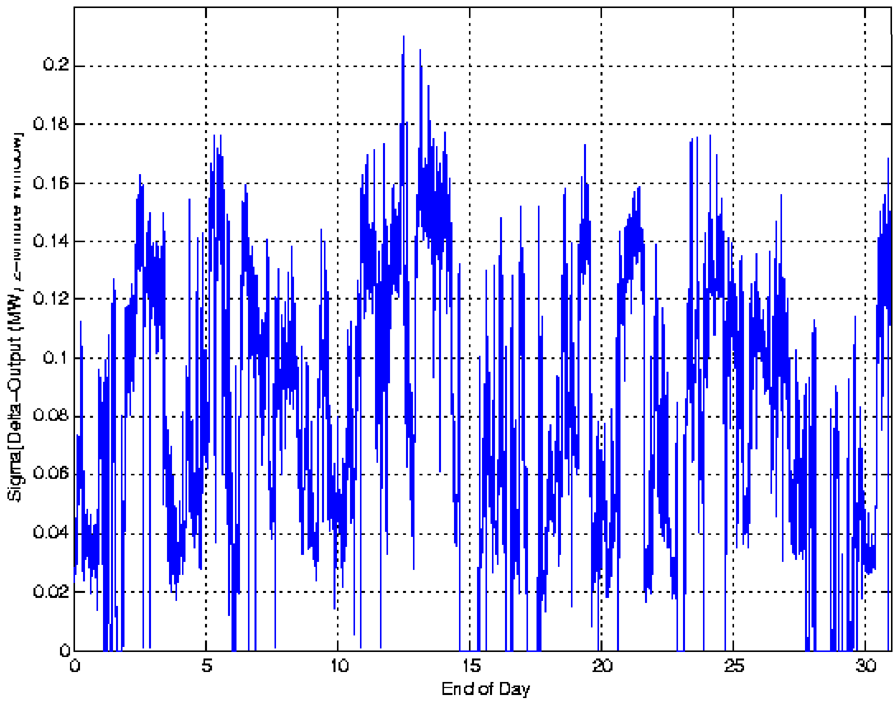

Figure 5.29 Rolling 10-minute Standard Deviation on One-second Change

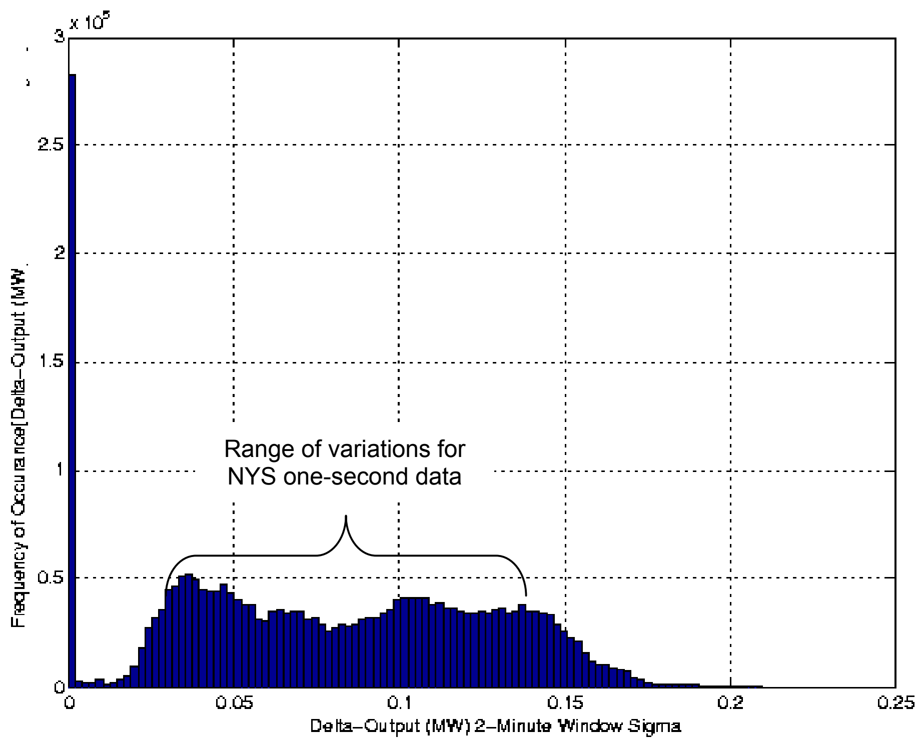

Figure 5.30 Histogram of Standard Deviation of One-second Change for Sliding 10-minute Window

5.4.3 Coincidence of Load and Wind Variability

For the six 10-minute, one-second resolution wind samples, there are three for which there are exactly corresponding New York State six-second load data sets (8/12/2003, 1/112003, and 4/17/2003). A histogram of the variance from the mean value of these 10-minute samples is shown in Figure 5.31. Similar histograms for the Superzone A-E and Zone K are shown in Figure 5.32 and Figure 5.33. The overall variation increases somewhat due to wind in each case. The statistics for these samples are summarized in Table 5.2. The most significant statistic is that the standard deviation at the state level increases by 12 MW from 71MW to 83 MW, which suggests that roughly 36 MW (3σ) increase in regulation capability would be required to maintain the same level of regulation compliance that New York State presently maintains. The present regulation of the NYSBPS exceeds minimum NERC criteria, so an increase in regulation capability is not expected to be required in order to meet minimum criteria with wind generation added to the system.

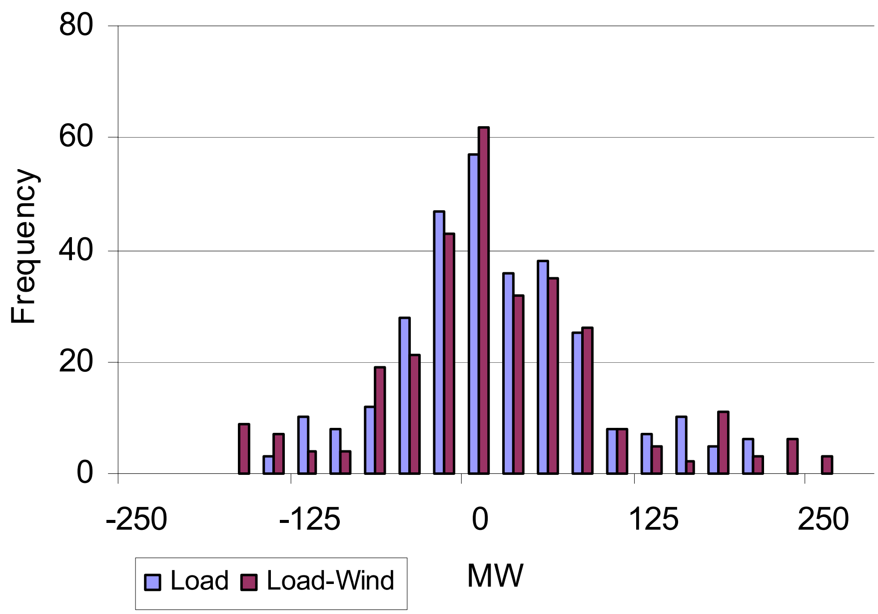

Figure 5.31 Histogram of Statewide 6-second Variance

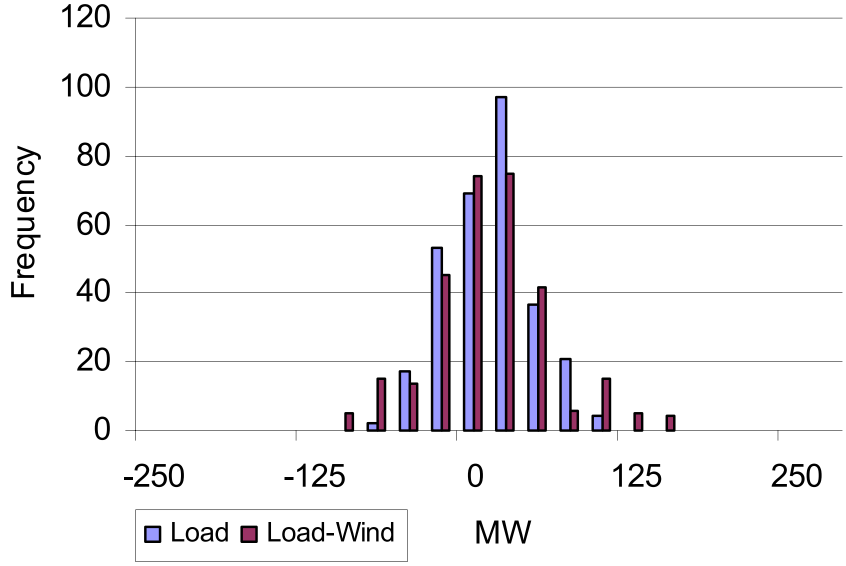

Figure 5.32 Histogram of Superzone A-E 6-second Variance

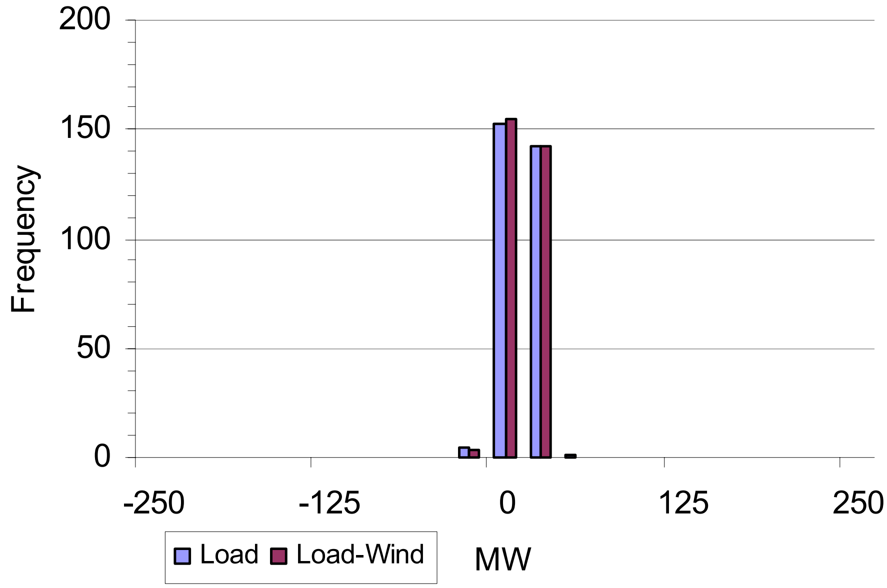

Figure 5.33 Histogram of Zone K 6-second Variance

Table 5.2 Statistics on six-second variability

	Zone K			Superzone			State		
Actual-Mean Delta	Load	Wind	Load-Wind	Load	Wind	Load-Wind	Load	Wind	Load-Wind
Mean	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Error	0.63	0.24	0.63	1.91	0.97	2.72	4.08	0.96	4.78
Median	-0.68	-0.17	-1.05	1.20	0.06	-0.65	-10.11	-1.23	-8.22
Mode	0.90	-0.36	2.12	11.20	0.88	xx	26.12	-4.93	-48.39
Standard Deviation	10.88	4.14	10.90	33.09	16.84	47.18	70.71	16.59	82.75
Sample Variance	118.31	17.18	118.84	1,094.90	283.52	2,225.96	5,000.34	275.14	6,847.94
Kurtosis	0.05	1.02	-0.30	-0.20	1.99	0.70	0.38	0.89	0.94
Skewness	-0.04	0.11	0.01	0.18	-0.33	0.27	0.40	0.06	0.42
Range	58.00	22.80	53.62	169.00	99.37	258.70	350.00	88.26	435.52
Minimum	-32.68	-9.73	-29.74	-81.16	-55.35	-118.81	-156.27	-49.70	-192.09
Maximum	25.32	13.07	23.88	87.84	44.02	139.89	193.73	38.56	243.43
Sum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Count	300	300	300	300	300	300	300	300	300

5.5 Conclusions and Recommendations

5.5.1 Conclusions

There is a slight increase in variability for each time frame of operation, related to scheduling, load following and regulation.

The NYSBPS is expected to have the capability to respond to the increase in variability with existing practice and generating resources, with no significant impact on reliability.

A slight increase in regulation, on the order of 36 MW is required to meet the present level of CPS performance. No increase is necessary to meet minimum NERC requirements.

These conclusions are based on presumption of system and individual generators performing in adherence to operating rules.

The operational impacts of these variations are further quantified in Section 6, *Operational Impacts*.

5.5.2 Recommendations

No immediate changes in operations due to the variability impacts of wind are required.

NYISO should monitor potential impacts on load following and regulation as wind penetration increases; noting any performance issues, including failure of participants to adhere to operating rules.

This page intentionally left blank.

6 Operational Impacts

The operational impacts of significant levels of wind generation cover a range of time scales. The annual, seasonal, daily and hourly impacts are described in Section 4, *Hourly Production Simulation Analysis*. The minute-to-minute or quasi-steady-state (QSS) and second-to-second or fundamental frequency stability impacts are described in this section. The QSS analysis evaluated 3-hour intervals under specific, time-variable load and wind conditions to determine the impact of wind on minute-to-minute changes to individual unit dispatch, in terms of load following and ramp rate requirements, as well as on the regulation requirements for units participating in automatic generation control (AGC). The stability analysis evaluated 1-second to 10-minute intervals to determine the impact of wind on system-wide transient stability performance, AGC performance, as well as the need, if any, for a variety of farm-level functions (e.g., voltage regulation, low-voltage ride through, etc). The selected QSS and stability time simulations are representative illustrations of system performance, and are intended to provide context to the statistical analysis presented in Section 5, *Wind and Load Variability*.

All analyses described in this section were performed using GE's PSLF (Positive Sequence Load Flow) and PSDS (Positive Sequence Dynamic Simulation) software package. Details of the QSS analysis are described in Section 6.1, *QSS Analysis*. The stability analysis is described in Section 6.2, *Stability Analysis*. Conclusions and recommendations are presented in Section 6.3, *Conclusions*.

6.1 QSS Analysis

The data, methods, tools, models, assumptions, study scenarios and results for the QSS analysis are described in the following subsections.

6.1.1 Approach

The objectives of the QSS analysis were to determine the impact of wind on 1) minute-to-minute changes to individual unit dispatch, in terms of load following and ramp rate requirements, as well as on 2) the regulation requirements for units participating in AGC and responding to changes in tie flows.

This was accomplished by performing a series of power flow solutions to simulate system performance on a minute-by-minute basis over selected 3-hour intervals. Each power flow in the series represented system conditions at a particular minute of the simulation. All loads varied from minute to minute. For simulations including wind generation, all wind farm power outputs varied from minute to minute. Finally, selected non-wind generating units were redispatched to accommodate the changes to load level or changes to both load level and wind generation.

Specifically, the following occurred in each QSS simulation at 1-minute intervals:

- all loads were modified according to a selected zonal load profile,
- all wind farm power outputs were modified according to a selected wind profile,
- all power required to balance total generation and load changes was assigned to a dummy generator acting as a proxy for all units on AGC.

The power output of the proxy unit approximated the amount of regulation required of all units on AGC between 5-minute redispatches of the system.

At 5-minute intervals, an additional operation was performed to emulate the economic dispatch of the system to follow load variations. The units that participate in the economic dispatch in a given study interval were redispatched with the objective of returning the AGC proxy unit output to near zero. Therefore, the following occurred every 5 minutes in each QSS simulation:

- all loads were modified according to a selected zonal load profile,
- all wind farm power outputs were modified according to a selected wind profile,
- all dispatchable units picked up a portion of the total change in load level and wind generation over the last 5 minutes, subject to individual ramp rate limits of 1% per minute,
- the impact of the application of the rate limits was identified as any dispatch requirements left over from the previous step,
- a second redispatch was performed to distribute that power among the units such that the load following is still achieved, but in a less economic manner,
- any remaining power required to balance total generation and load (i.e., maintain swing machine power output) was assigned to the AGC proxy generator.

The results of each 3-hour QSS simulation included zonal loads (MW), total New York State load (MW), zonal wind generation (MW), total New York State wind generation (MW), individual dispatchable unit power output (MW), selected internal interface flows (MW), tie flows between New York State and its neighbors (MW), impact of application of rate limits (MW), and dummy generator output (MW) as a proxy for all AGC units.

Additional details of the QSS analysis approach are discussed in the following subsections. The results are discussed in Section 6.1.2, *Results*.

6.1.1.1 Data

Four types of data were used in the QSS analysis: power flow databases, individual wind farm output profiles, zonal load profiles and MAPS hourly simulation results. Each is described below.

6.1.1.1.1 Power Flow Databases

NYISO provided three power flow databases for Phase I of this project, representing peak, light, and intermediate New York State load levels without significant wind generation. The same power flows were available for the QSS analysis. They represented the system conditions, i.e., total New York State generation and load, shown in Table 6.1. The QSS analysis was performed using the light load databases, since they best matched the study scenarios, as described in Section 6.1.1.2, *Study Scenarios*.

Table 6.1. Summary of QSS Power Flow System Conditions with No Wind Generation.

	Light Load	**Intermediate Load**	**Peak Load**
Total NY State Generation	14,514 MW	25,826 MW	32,525 MW
Total NY State Load	14,174 MW 5,797 MVAr	26,325 MW 10,873 MVAr	32,889 MW 13,597 MVAr

Power flows were also developed to represent the New York State system with the primary wind generation scenario, as described in the Section 1, *Introduction*. Thirty-seven individual wind farms were added to each of the above databases. Each wind farm was connected directly to a designated substation and represented by a single equivalent machine. The majority of the interconnections were at the 115kV voltage level and above. Four of the Long Island interconnections were at the 69kV voltage level. No interconnections were below 69kV. The output of each wind farm was set by the selected wind profile. The total initial output from all 37 wind farms varied from about 500 MW to 2300 MW in this part of the study. The system redispatch required to accommodate wind generation followed the dispatch patterns observed in the MAPS simulations, as discussed in Section 6.1.1.1.4, *MAPS Simulation Results.*

6.1.1.1.2 Wind Profiles

AWS TrueWind provided individual wind farm output (MW) data for each of the sites included in the primary study scenario. Data with 1-minute resolution was used for the QSS analysis.

The 1-minute data included selected 3-hour intervals from different times of year and different periods of the day for a total of 108 potential wind events. Forty-five intervals represented typical wind farm output levels. Another forty-five intervals were similar but with higher levels of minute-to-minute variability. Eighteen intervals represented the largest observed changes in wind generation output, primarily due to the wind's diurnal cycle. A selection of the 1-minute data from each of the three categories is shown in Figure 6.1. Each trace represents the total New York State wind generation level (MW) for a specific 3-hour interval.

The 1-minute data was used as provided to set the wind farm output (MW) for each site during the QSS analysis. Additional information on the AWS TrueWind data is provided in Appendix A.

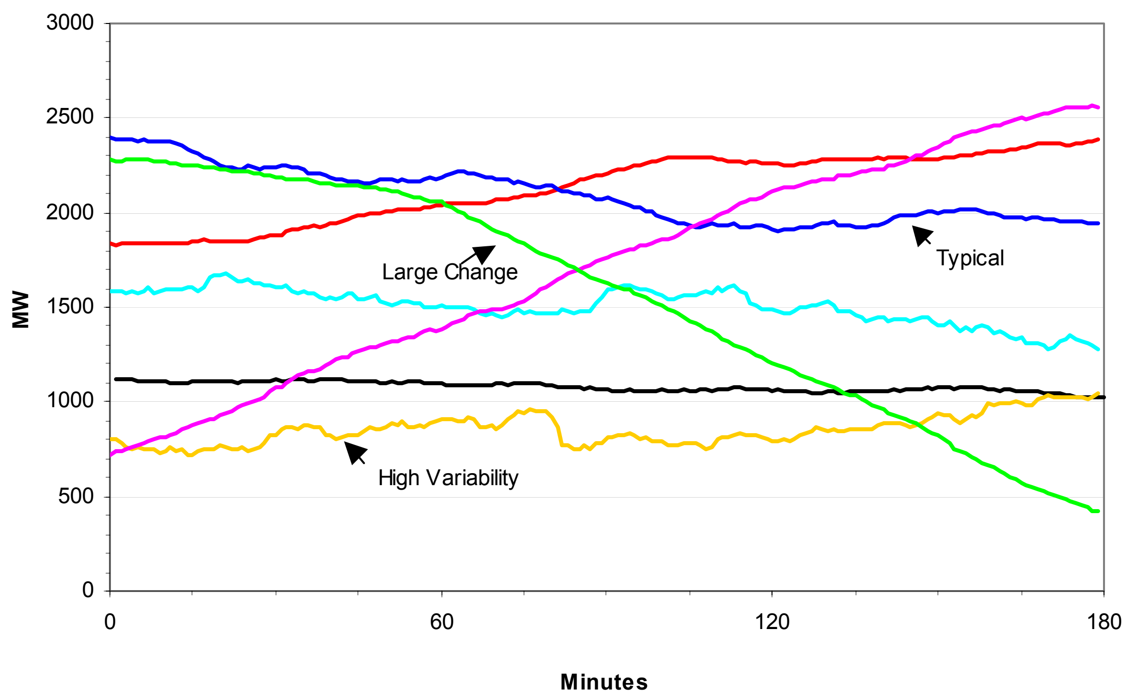

Figure 6.1 Total New York State Wind Generation (MW) over Selected 3-Hour Intervals.

6.1.1.1.3 Load Profiles

NYISO provided 6-second zonal load data (MW) for each day in January, April, August, and October 2003. An example for August 21, 2003 is shown in Figure 6.2. The black trace represents the total New York State load (MW, left scale). Each of the other lines represents a specific zonal load (MW, right scale) as identified in the legend. Some step changes in the data are observed, indicating either disturbances on the system or data anomalies. Study results were not affected by these anomalies.

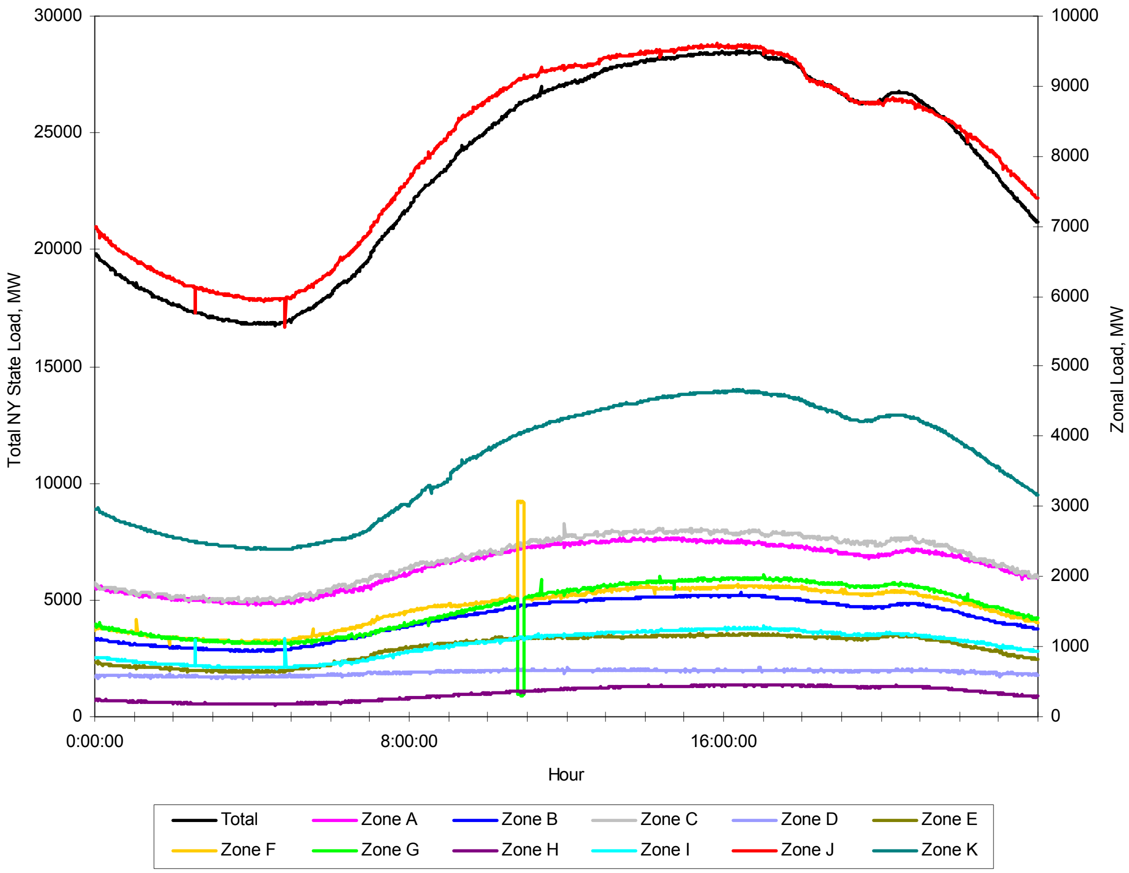

Figure 6.2 Example Load Profile from August 2003.

For the QSS analysis, the zonal load profiles were sampled every minute and then used to set the power level for all individual loads in New York State. Specifically, a change in zonal load from one minute to the next was spread across all loads in that zone, proportional to the size of an individual load.

6.1.1.1.4 MAPS Simulation Results

The results of MAPS simulations were used in the QSS analysis to 1) guide the system redispatch required to accommodate wind generation in the power flows, and 2) determine which units would be redispatched during a given 3-hour study interval to meet changes in load level or changes in both load level and wind generation. The MAPS simulations with wind assumed that the forecast was 100% accurate. That is, the schedule used for the commitment of the thermal generation assumed perfect foreknowledge of the wind generation. As a result, the minimum number of thermal units will be committed and therefore, available for load following. For the purposes of the QSS analysis, this represents a conservative assumption.

The MAPS simulations showed which non-wind generating units participated in load following over the study interval. Thus, dispatchable units are identified on an economic basis. Once these dispatchable units were identified, each was assigned a participation factor for the QSS analysis. The participation factor allotted some fraction of the redispatch requirements (MW) from one-minute to the next to a unit identified as dispatchable. The allotted fraction was proportional to the amount of redispatch observed on the unit in the MAPS results, compared to the total amount of redispatch required over a 3-hour interval. As an equation, the participation factor can be defined as follows:

$PF = MW_i/MW_{total}$

where: MW_i = MW change on i^{th} unit over 3-hour interval

MW_{total} = total MW change on all dispatchable units over 3-hour interval

Only the larger (over 50 MW) units in New York State were assigned a participation factor. Any scheduled changes in the output of small units which occurred over a given 3-hour interval were effectively added to the amount of redispatch required of the units with participation factors. Similarly, changes in tie flows between New York State and its neighbors were ignored. Therefore, any tie changes over a 3-hour study period were also effectively added to the amount of redispatch required of the New York units with participation factors. These are conservative assumptions, which require all of New York State's load following requirements to be met by New York generating units. In addition, the analysis focused on the *difference* between system performance (e.g., load following requirements) with and without wind generation. As a result, the absolute requirements were of secondary importance.

Details of the MAPS analysis are described in Section 4, *Hourly Production Simulation Analysis*.

6.1.1.2 Study Scenarios

The QSS study scenarios were selected to be severe, but likely, tests of the operational impacts of significant amounts of wind generation on New York State system performance. As noted in Section 7, *Effective Capacity*, the diurnal cycle of wind generation is generally opposite that of system load. For example, as load increases in the morning, wind generation decreases. Therefore, the analysis focused on large state-wide changes in wind generation paired with large state-wide changes in load level of the opposite sign.

The wind profile data, as provided by AWS TrueWind, was screened to identify the most stressful wind generation scenarios over a given 3-hour interval. The goals were as follows:

- Identify the largest state-wide increase in wind generation
- Identify the largest state-wide decrease in wind generation
- Identify the highest rate of increase in wind generation
- Identify the highest rate of decrease in wind generation
- Identify the highest level of minute-to-minute variability

Five wind profiles were selected, and are shown in Figure 6.3. The red line represents a September morning decrease in wind generation with the highest rate of change over a 15-minute period. The green line represents an August morning with the absolute largest decrease in wind generation over a 3-hour interval. The black line represents a May evening increase in wind generation with the highest rate of change over a 15-minute period. The blue line represents an October evening with the absolute largest increase in wind generation over a 3-hour interval. The pink line represents an April afternoon with little absolute change in wind generation but a high level of variability. Note that the largest statewide changes in wind generation coincided with the largest changes in wind generation across zones A through E. Therefore, one profile represents both the largest statewide changes as well as the largest Superzone A-E changes.

The majority of the wind generation was located in Superzone A-E, from 65% in the May wind scenario to 90% in the September wind scenario. This represented a penetration (Superzone A-E wind generation as a percent of Superzone A-E load) ranging from 10% in the October wind scenario to 40% in the August wind scenario. The above values represent system conditions at the beginning of a 3-hour interval.

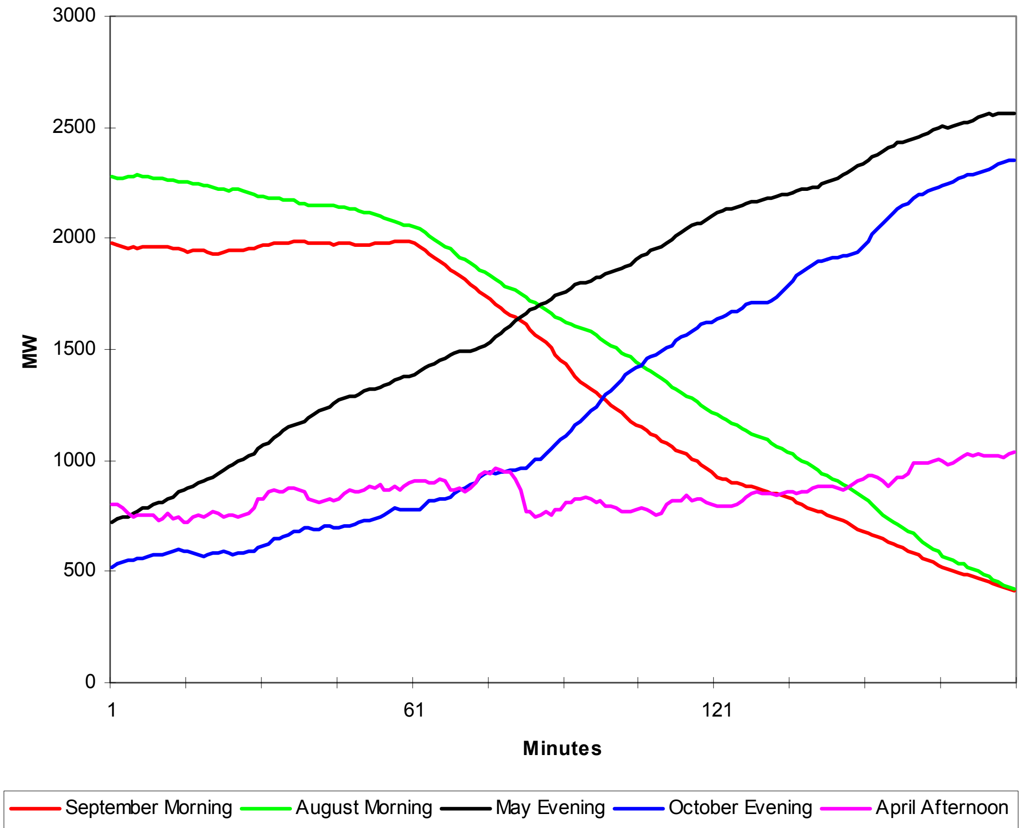

Figure 6.3 Wind Generation Study Scenarios.

Next, the load profiles, as provided by NYISO, were screened to identify 3-hour load intervals to pair with the selected wind generation scenarios. The goals were to identify 1) a large state-wide increase in load to pair with the decreasing wind generation scenarios, 2) a large state-wide decrease in load to pair with the increasing wind generation scenarios, and 3) a near-zero change in state-wide load to pair with the highly variable wind generation scenario. No exact time synchronization between the wind and load scenarios was possible. However, the time of year and time of day coincided. The wind and load scenarios selected for evaluation in the QSS analysis are shown in Figure 6.4. The solid lines represent the wind generation scenarios as shown in Figure 6.3, with the scale on the left. The dotted lines represent the selected load scenarios, with the scale on the right. The August morning load scenario (red dotted line) was paired with both the August and September morning wind generation scenarios. The October evening load (blue dotted line) was paired with the May and October evening wind generation scenarios. The April afternoon load scenario (pink dotted line) was paired with the April afternoon wind generation scenario.

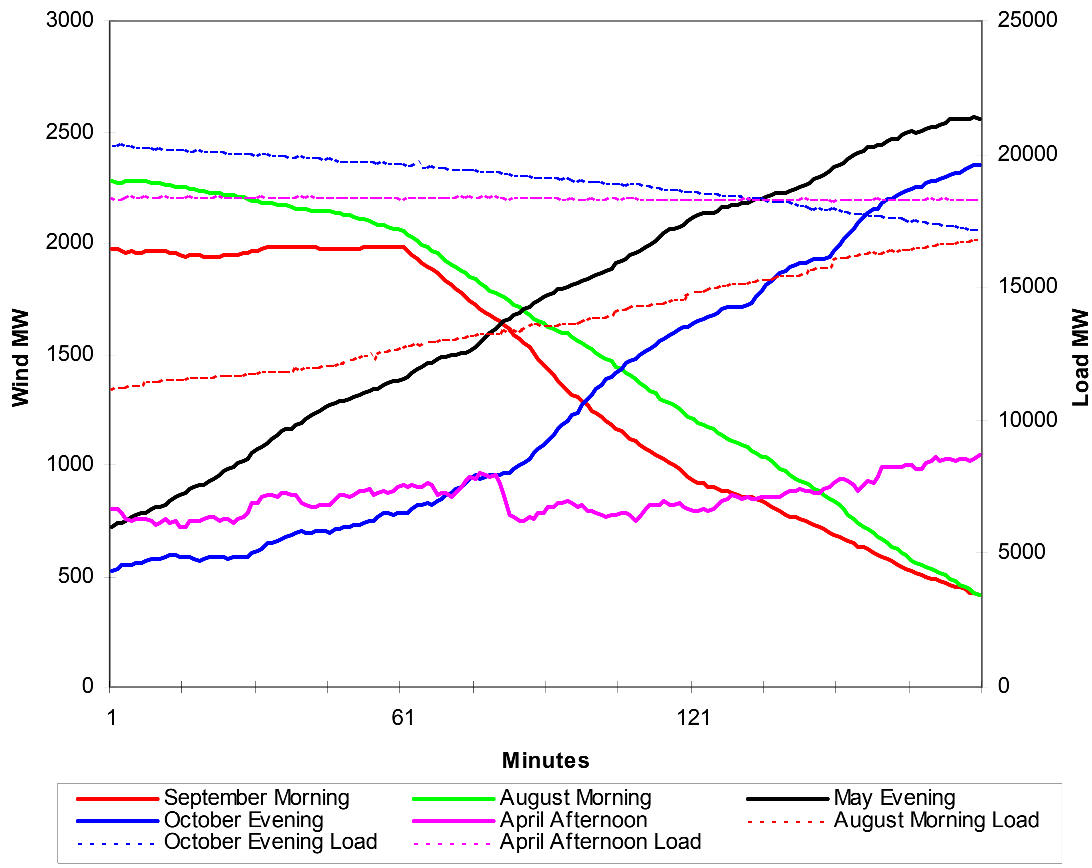

Figure 6.4 Wind and Load Study Scenarios.

A statistical analysis of wind and load variability was presented in Section 5, *Wind and Load Variability*. Figure 6.5 illustrates the relationship between a selected 3-hour QSS study scenario and that analysis. The distribution of hourly changes in summer morning load level is represented by the blue bar. The distribution of hourly changes, over the same time period, in both wind generation and load level is represented by the burgundy bar. The QSS August morning load scenario exhibits hourly changes from 1700 MW to 2100 MW. The combination of the August morning load and wind scenarios exhibits hourly changes from 2300 MW to 2700 MW. These ranges are also indicated in the figure.

A comparison of 5-minute changes from the running average is shown in Figure 6.6. The distribution of 5-minute changes due to load is represented by the blue bar, and the distribution due to the combination of wind generation and load level is represented by the burgundy bar. The QSS August morning load scenario exhibits 5-minute changes from 140 MW to 170 MW. The combination of the August morning load and wind scenarios exhibits 5-minute changes from 190

MW to 230 MW. These ranges are also indicated in the figure. Thus, the study scenarios represent severe tests of the impact of significant wind generation on system performance, in terms of both hourly and 5-minute variability.

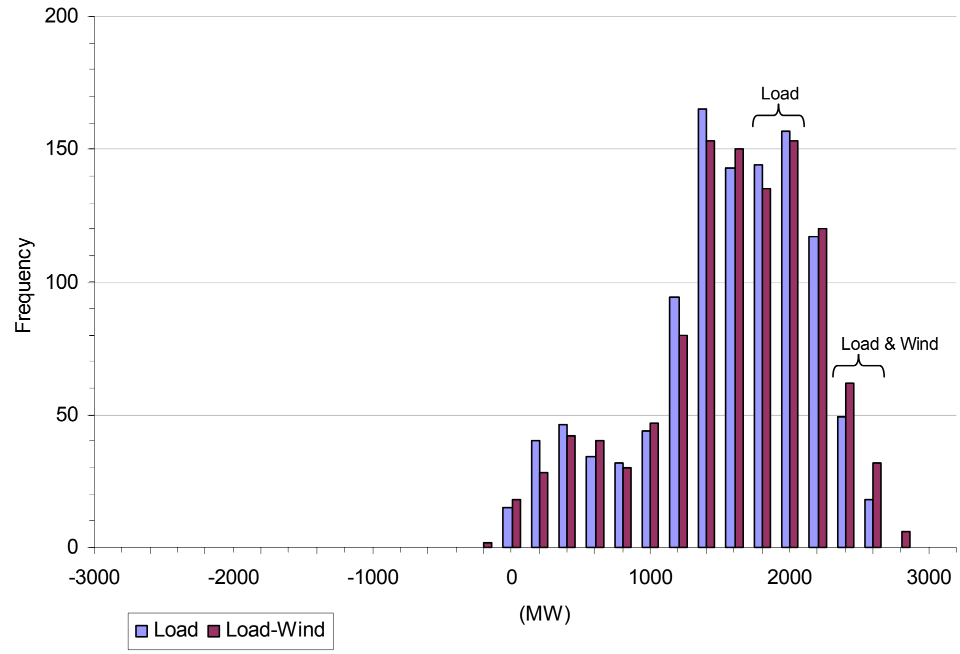

Figure 6.5 Distribution of Hourly Wind and Load Variations.

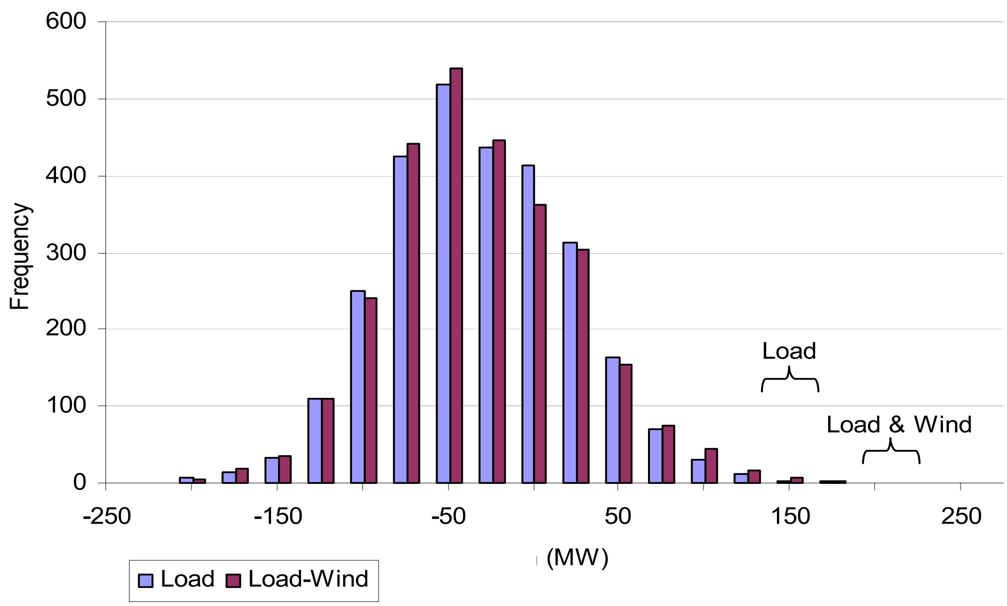

Figure 6.6 Distribution of 5-Minute Wind and Load Variations.

Finally, the non-wind generation units available for redispatch in a given 3-hour interval were identified from the MAPS simulation results, as described in Section 6.1.1.1.4, *MAPS Simulation Results*. Again, exact time synchronization was not possible. However, the time of year and time of day coincided. In addition, the MAPS results were selected such that the state-wide changes in wind and load in MAPS approximated the state-wide changes in wind and load as defined by the selected wind and load profiles.

A summary of the study scenarios is shown in Table 6.2. The change over a given 3-hour interval in total NYS load and total NYS wind generation, as well as the number of units participating in the load following, are shown in this table.

The QSS load following simulations were designed to be conservative compared to the expected capability of the NYSBPS. Therefore, fewer units were assigned to load following in the QSS simulations than in the MAPS analysis. Specifically, all of the QSS load following was performed by large New York generating units (>50MW) shown by MAPS simulations to participate in the economic dispatch. Small units that changed dispatch over a 3-hour interval were ignored. More important, increases in imports over a 3-hour interval were ignored.

For example, in the August morning load rise QSS simulation, the 60 units participating in load following represented 60% of the generation dispatch changes observed in MAPS over that 3-hour interval. The MAPS simulation also showed that the increase in imports represented 23% of the required load following and the remaining generation dispatch changes were on small units. In other words, 100% of the QSS load following was performed by the participants who supplied 60% of the load following in the MAPS simulations.

This conservative approach allowed the QSS analysis to focus on the *difference* between system performance (e.g., load following requirements) with and without wind generation.

Table 6.2 Summary of QSS Study Scenarios.

Case	Δ NYS Load (MW)	Δ NYS Wind (MW)	# Δ Units
August Morning Load	5696	NA	60
August Morning Wind+Load	5696	-1861	65
September Morning Wind+Load	5696	-1561	65
October Evening Load	-3210	NA	19
May Evening Wind+Load	-3210	1837	29
October Evening Wind+Load	-3210	1834	29
April Afternoon Load	-45	NA	3
April Afternoon Wind+Load	-45	240	4

6.1.2 Results

The discussion of the QSS results is split into three subsections. Section 6.1.2.1, *Large-Scale Wind and Load Changes* discusses the impact of large changes in load level and wind generation on system performance. Section 6.1.2.2, *Wind Generation Variability* discusses the impact of minute-to-minute wind generation variability, and Section 6.1.2.3, *Active Power Control* reports on the impact of wind generation with an Active Power Control function.

6.1.2.1 Large-Scale Wind and Load Changes

The results of the first six study scenarios, as shown in Table 6.2 are discussed in this section. The impact of large decreases in wind generation, paired with large increases in system load level, are discussed in Section 6.1.2.1.1, *Wind Generation Drop/Load Level Rise Combination*. The impact of large increases in wind generation, paired with large decreases in system load level, are discussed in Section 6.1.2.1.2, *Wind Generation Rise/Load Level Drop Combination*.

6.1.2.1.1 Wind Generation Drop/Load Level Rise Combination

Selected results of the 3-hour QSS simulation with the August morning load profile, and no wind generation, are shown in Figure 6.7. The pink line represents the total New York State load (MW, left axis), the blue line represents AGC proxy unit output (MW, right axis), and the green line represents the impact of the application of rate limits (MW, right axis). Similar QSS results for the combination of the August morning load profile with the August and September wind profiles are shown in Figure 6.8 and Figure 6.9, respectively. In both figures, an additional light blue line represents total New York State wind generation (MW, left axis).

The results show two instances in which the application of ramp rate limits impacted the economic dispatch for the August load only scenario. The largest ramp rate impact was 7 MW. The largest impact of ramp rate limits was 4 MW and 5 MW for the August and September wind profiles, respectively. Note that more units were assigned to economic dispatch duty with wind, compared to the load only case, on the basis of the MAPS simulation results. Therefore, ramp rate limitations were reduced. Load following capability is not affected by the application of rate limits, but the units performing that duty may or may not be the most economic. In other words, there is no change in unit commitment, but some of the load following is performed by sub-economic units.

A cross plot of the AGC proxy unit output (MW), which approximates the regulation required between system redispatches, is shown in Figure 6.10 for the three cases. The blue line represents the August morning load only scenario, the solid red line represents the August wind scenario, and the dotted red line represents the September wind scenario. This plot illustrates the increase in regulation requirements due to the addition of wind generation.

The majority of peak values are in the range of 100 MW to 200 MW. The absolute peak was 273 MW for the August load only scenario. The absolute peak proxy AGC unit output with the August wind profile was 297 MW; the peak for the September wind profile was 353 MW. The increase for the September scenario coincided with the high rate of change observed near the midpoint of this wind profile. The average value of the peak AGC unit output was 125 MW, 163 MW, and 154 MW for the August load only, August wind, and September wind scenarios, respectively. These values are consistent with the 5-minute 3σ variation, 165 MW, calculated in Section 5.3, *Five-Minute Variability*.

A cross plot of the output of an example unit (MW) assigned to the economic dispatch is shown in Figure 6.11. The blue line represents the August morning load only scenario, the solid red line represents the August wind scenario, and the dotted red line represents the September wind scenario. Note that the QSS analysis only approximates real generating unit behavior. For example, real unit power outputs ramp smoothly between operating points. The stair step results of the QSS analysis approximate that behavior and illustrate key points. Specifically, the difference in initial operating point reflects the redispatch required to add wind generation to the system, and the difference in rate of increase in output indicates the increased load following requirements due to the addition of wind.

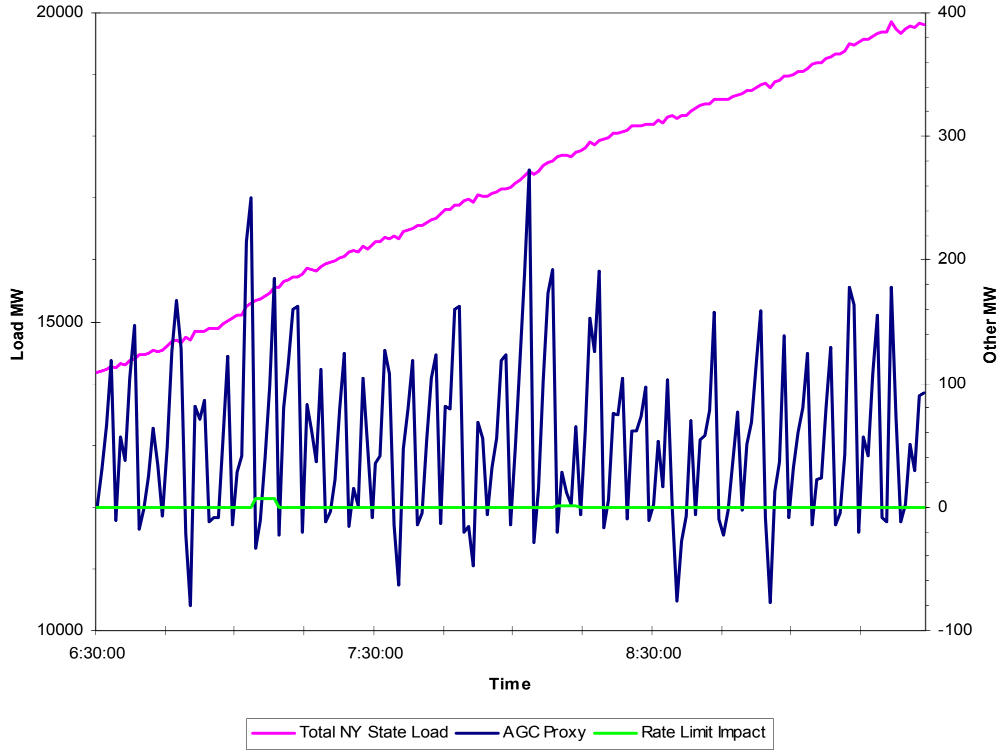

Figure 6.7 QSS Results for August Morning Load Rise, No Wind Generation.

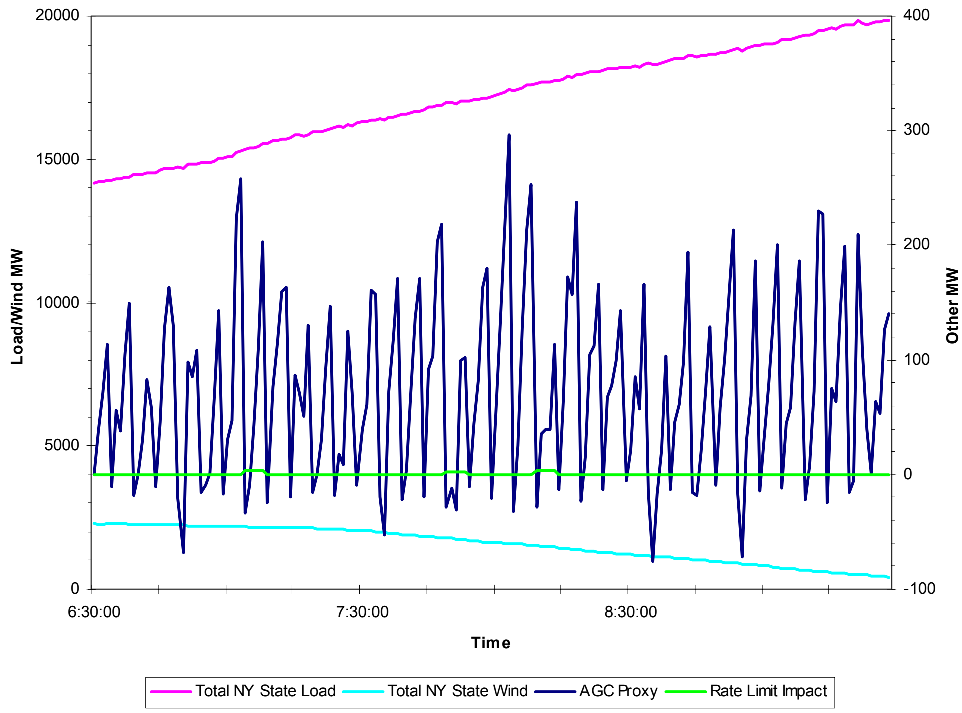

Figure 6.8 QSS Results for August Morning Load Rise, August Wind Generation Decrease.

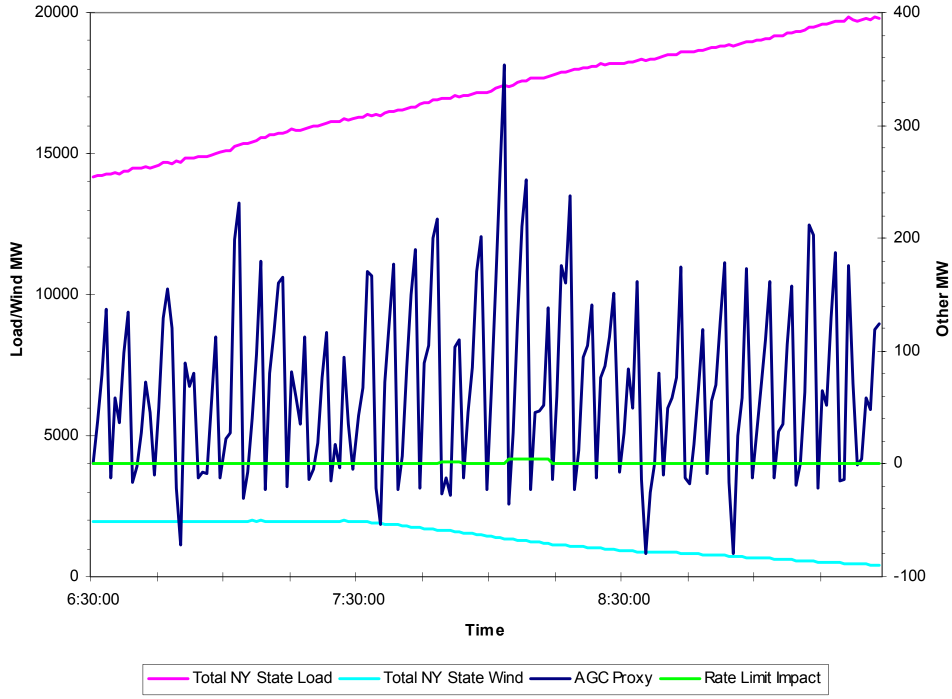

Figure 6.9 QSS Results for August Morning Load Rise, September Wind Generation Decrease.

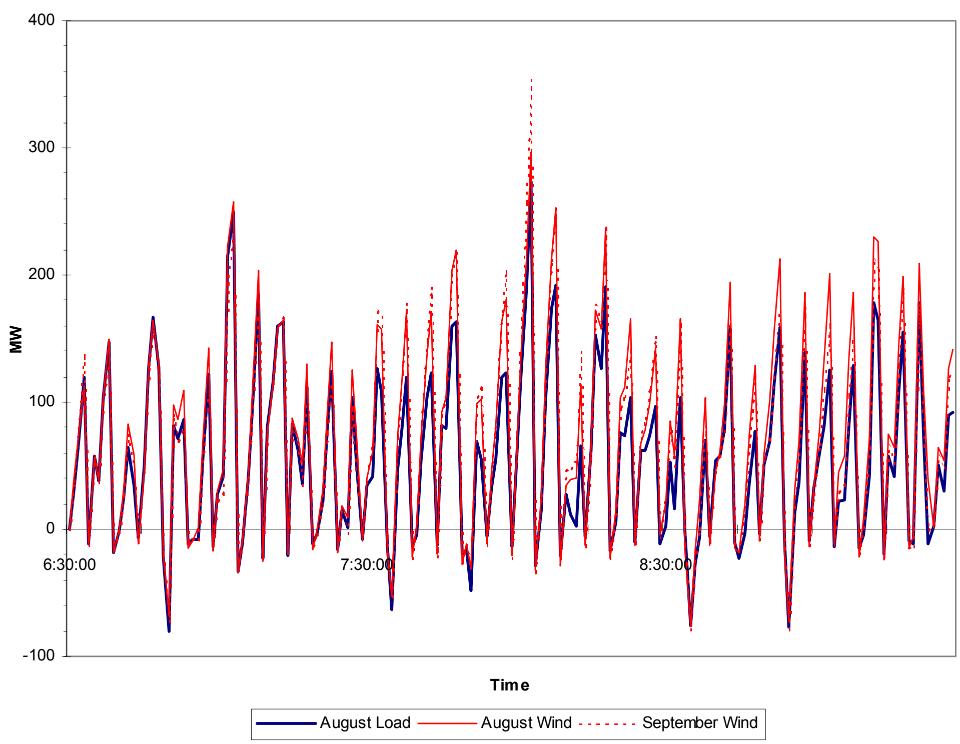

Figure 6.10 AGC Proxy Unit Output for August/September Study Scenarios.

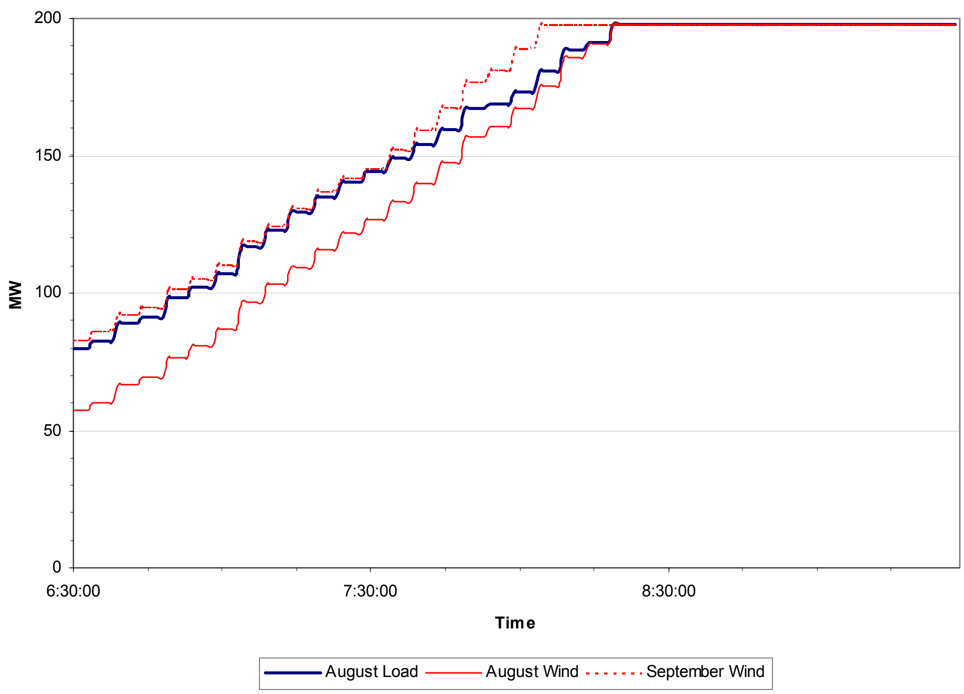

Figure 6.11 Example Unit Output for August/September Study Scenarios.

6.1.2.1.2 Wind Generation Rise/Load Level Drop Combination

A reduced set of plots are provided in the following discussion of the 3-hour QSS simulation of the October evening load profile, either alone or in combination with the October and May wind profiles.

A cross plot of the AGC proxy unit output (MW) for the three cases is shown in Figure 6.12. The blue line represents the October evening load only scenario, the solid red line represents the May wind scenario, and the dotted red line represents the October wind scenario. This plot illustrates the increase in regulation requirements due to the addition of wind generation. Note that the sign has changed from that observed in the August scenarios because the wind and load profiles have changed direction.

The majority of the minimum values are in the range of -50 MW to -150 MW. The absolute minimum was -210 MW for the October load only scenario. The absolute minimum proxy AGC unit output with the May wind profile was -260 MW; the minimum for the October wind profile was -315 MW. The increase for the October scenario coincided with a high rate of change observed in this wind profile. The average value of the peak AGC unit output was -78MW, -114

MW, and –114 MW for the October load only, October wind, and May wind scenarios, respectively. These values are consistent with the 5-minute 3σ variation, 165 MW, calculated in Section 5.3, *Five-Minute Variability*.

A cross plot of the impact of rate limits (MW) for the three cases is shown in Figure 6.13. The blue line represents the October evening load only scenario, the solid red line represents the May wind scenario, and the dotted red line represents the October wind scenario. Applying rate limits (1%/minute) had a more significant impact on these scenarios than on the August scenarios, since fewer units were assigned to the economic dispatch. Given the conservative assumptions in the assignment of units to dispatch duty, as outlined in Section 6.1.1.1.4, *MAPS Simulation Results*, the focus was on the difference between various cases not on the absolute results. Therefore, the sub-economic load following increased by approximately 9 MW for the May wind scenario and by about 24 MW for the October wind scenario. As noted before, this is not a change in unit commitment. Rather, some of the load following is performed by sub-economic units.

The amount of energy per hour redistributed from the most economic units to other less economic units is a quantitative measure of the amount of sub-economic load following. The energy per hour of sub-economic load following was 4.7 MWh/hr, 5.3 MWh/hr, and 4.2 MWh/hr for the October load only, October wind, and May wind scenarios, respectively. The largest difference was observed for the October wind scenario, which resulted in a 0.6 MWh/hr increase in sub-economic load following.

The combination of decreasing load and increasing generation will not adversely impact system reliability. However, it will need to be accommodated by operations.

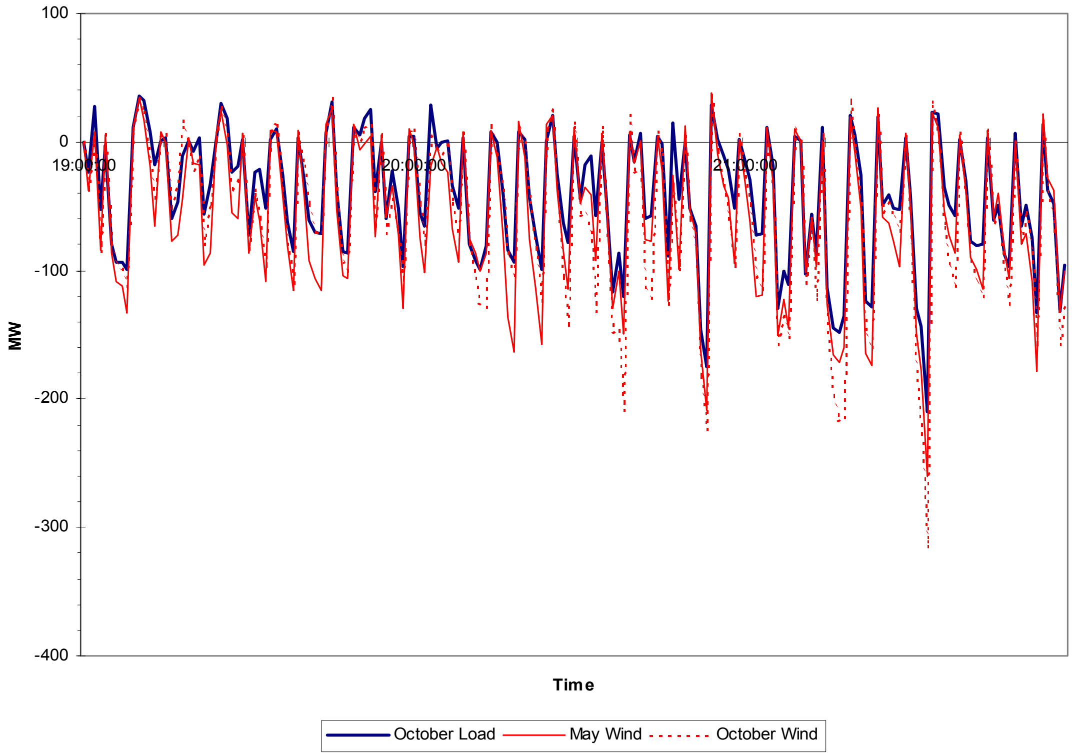

Figure 6.12 AGC Proxy Unit Output for May/October Study Scenarios.

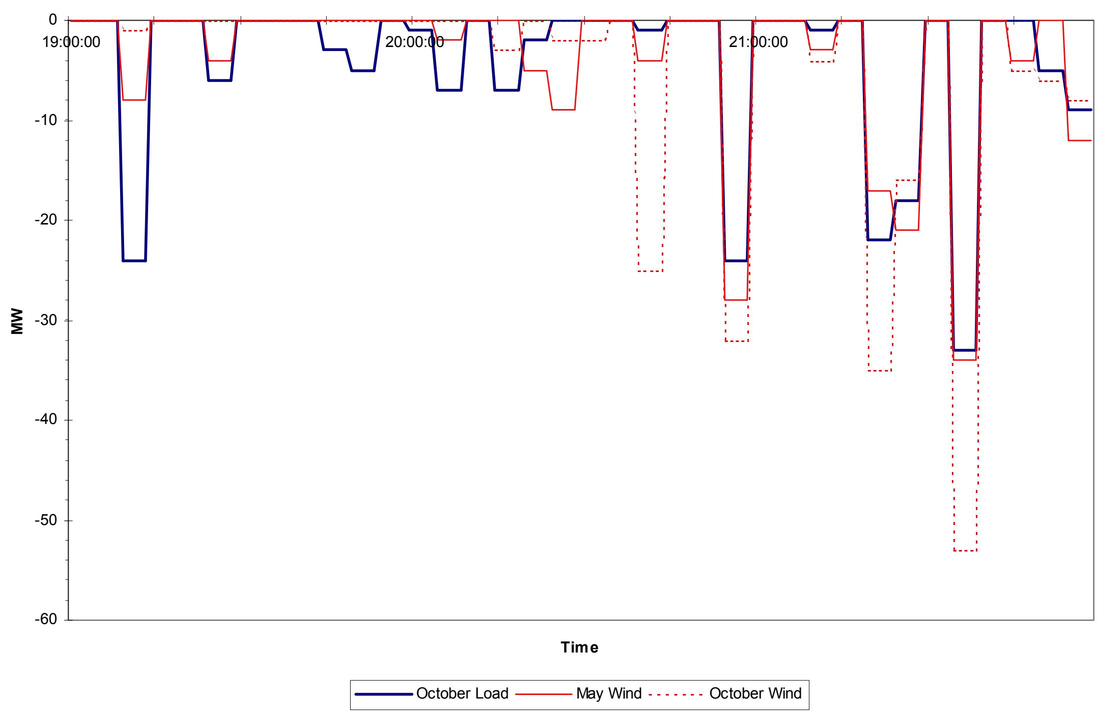

Figure 6.13 Rate Limit Impact for May/October Study Scenarios.

6.1.2.2 Wind Generation Variability

The results of the final two study scenarios, as shown in Table 6.2 are discussed in this section. The April load scenario was chosen for its relatively small changes over the 3-hour study interval. The April wind scenario was chosen for its relatively high minute-to-minute changes over the same interval.

Both the AGC proxy unit output and the impact of rate limits are shown in Figure 6.14. The solid blue line represents the proxy unit output (MW) for the April load only scenario, the dotted blue line represents the proxy unit output for the April wind scenario, the solid red line represents the impact of rate limits (MW) on the April load only scenario, and the dotted red line represents the impact of rate limits on the April wind scenario.

The average of the AGC proxy unit output hovers near zero, but this is not a meaningful measure of regulation needs with a nearly constant load. It is the dynamic range, from largest negative value to largest positive value, that is important. This range was 170 MW for the load only scenario, and 269 MW for the wind and load scenario. This additional regulation was required to achieve the same level of performance for the wind scenario. It also indicates that the regulation needs of the system may be higher than previously observed during some parts of the year. However, the total regulating range requirement of 269 MW is consistent with current practice as described in Section 5.4.1, *AGC Performance*, and less than that observed for the August morning load only scenario. Hence, it can be met with modifications to the current processes.

A 60 MW increase in the sub-economic load following of the units on economic dispatch was also observed. Note that both scenarios used relatively few units (3 or 4) to perform the economic dispatch. Realistically, more units would be available to follow load. Nevertheless, this indicates that more load following may be needed during time periods when system load has historically been nearly constant.

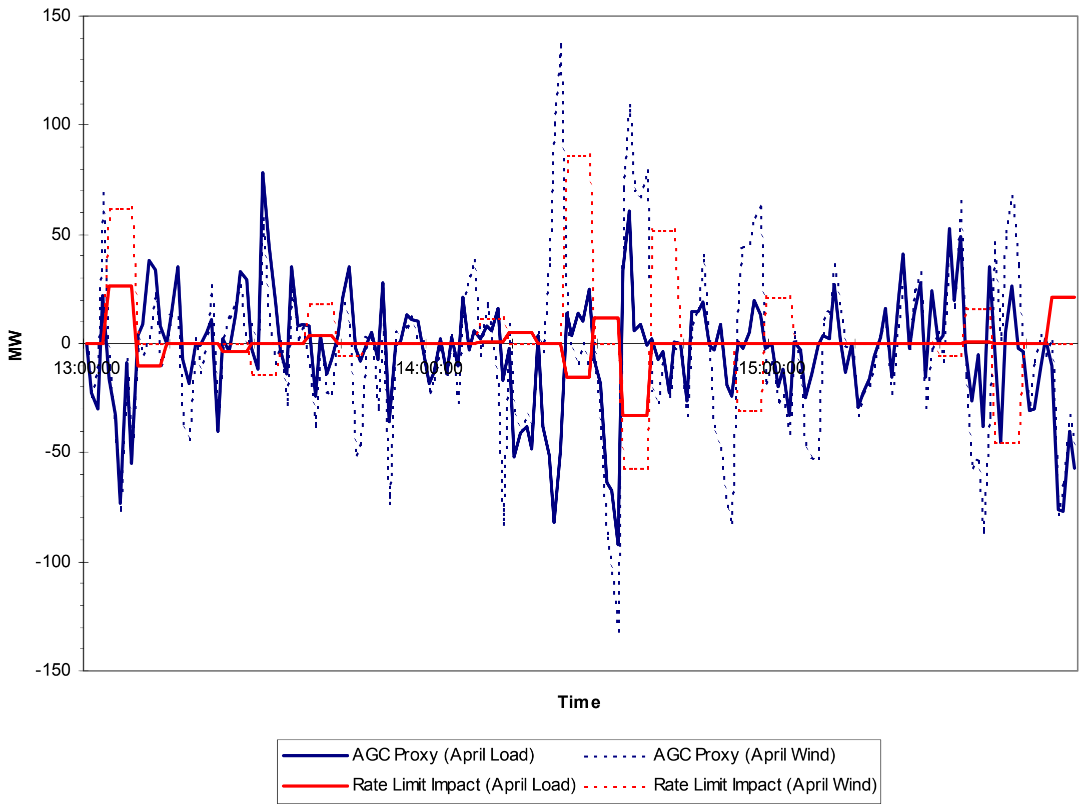

Figure 6.14 AGC Proxy Unit Output and Rate Limit Impact for April Study Scenarios.

6.1.2.3 Active Power Control

While active power control (APC) is not an industry-standard capability for wind turbine-generators, Phase I of this project recommended its future consideration. Therefore, the impact of one particular type of APC on system performance was evaluated. In general, an APC function could be used to reduce wind farm output to meet specific performance objectives. Note that it is uni-directional and cannot increase wind farm output above that associated with a given wind speed.

One type of APC was evaluated as part of the QSS analysis. This particular APC was a ramp rate limit, and constrained wind farm power output increases to no more than 1% of maximum output. The goal of such an APC would be to reduce wind generation variability, as well as to reduce the amount of regulation and load following required of other units.

Previous results, as described Section 6.1.2.1.2, *Wind Generation Rise/Load Level Drop Combination*, showed acceptable system performance with an unconstrained wind scenario. The aggressive (1%) ramp rate limit was selected to illustrate potential performance. It does not constitute a recommendation.

To test the APC, the October evening wind profiles were modified such that all wind farm outputs were subject to the 1% ramp rate limit on increases in generation, but not decreases. A comparison of an individual wind farm's output (MW) with and without APC is shown in Figure 6.15. The red line represents the original October evening wind profile for site 15. The blue line represents the modified wind profile for site 15, subject to the rate limits applied by the APC. A comparison of total New York state wind generation (MW) with and without APC is shown in Figure 6.16. Again, the red line represents the original wind profile and the blue line represents the wind profile as modified by the APC. The difference between the constrained and unconstrained wind generation profiles represents an adverse impact on energy production associated with a ramp rate limit function. For this example, the lost energy was approximately 6% of the total original energy. Therefore, such a function should only be used in specific applications to ensure system reliability.

A QSS simulation was performed using the above APC limited wind profile. A cross plot of the AGC proxy unit output (MW) is shown in Figure 6.17. The blue line represents the October evening load only scenario, the solid red line represents the original October wind scenario, and the dotted red line represents the APC limited October wind scenario. This plot illustrates the decrease in regulation requirements due to the APC. The majority of the minimum values are in the range of –50 MW to –150 MW. The absolute minimum was –210 MW for the October load only scenario. The absolute minimum proxy AGC unit output for the original October wind profile was –315 MW. The minimum value for the APC limited October wind profile was –270 MW, representing about 45 MW of improvement.

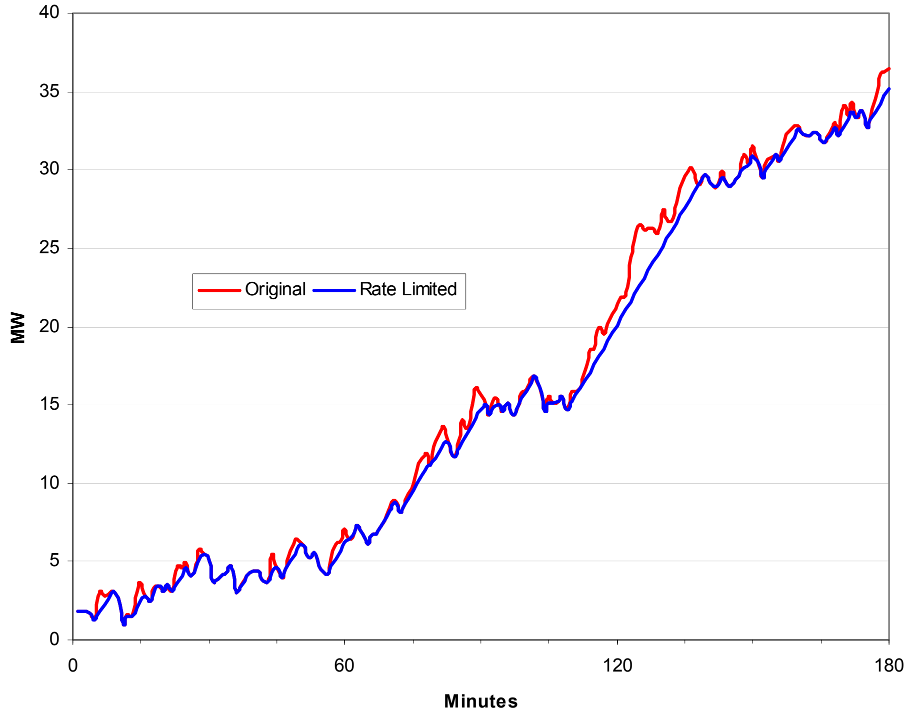

Figure 6.15 Individual Wind Farm Power Output with and without Active Power Control.

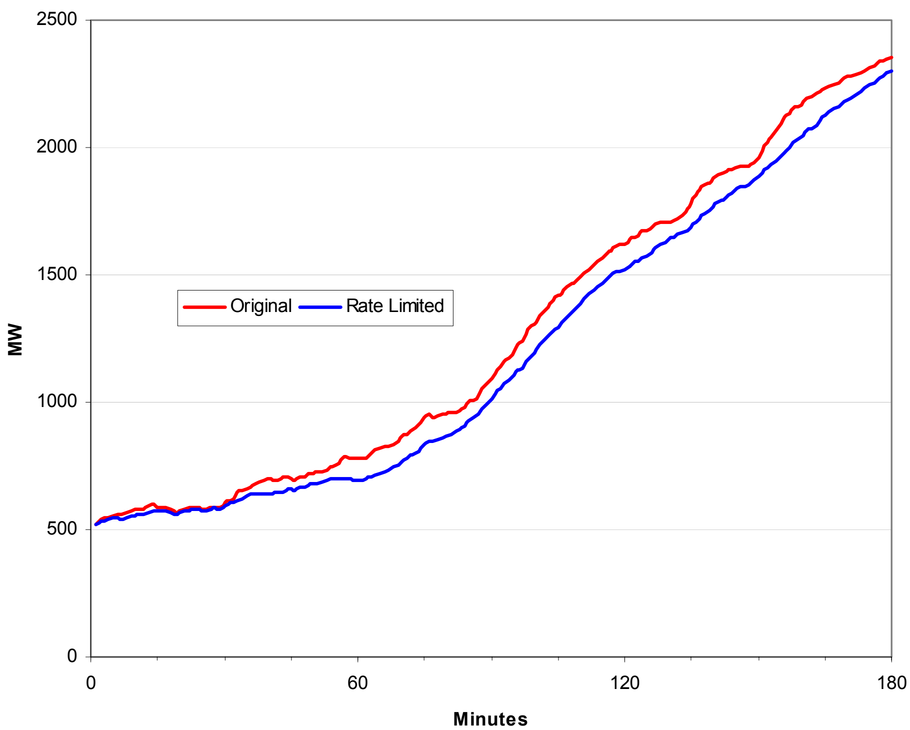

Figure 6.16 Total New York State Wind Generation with and without Active Power Control.

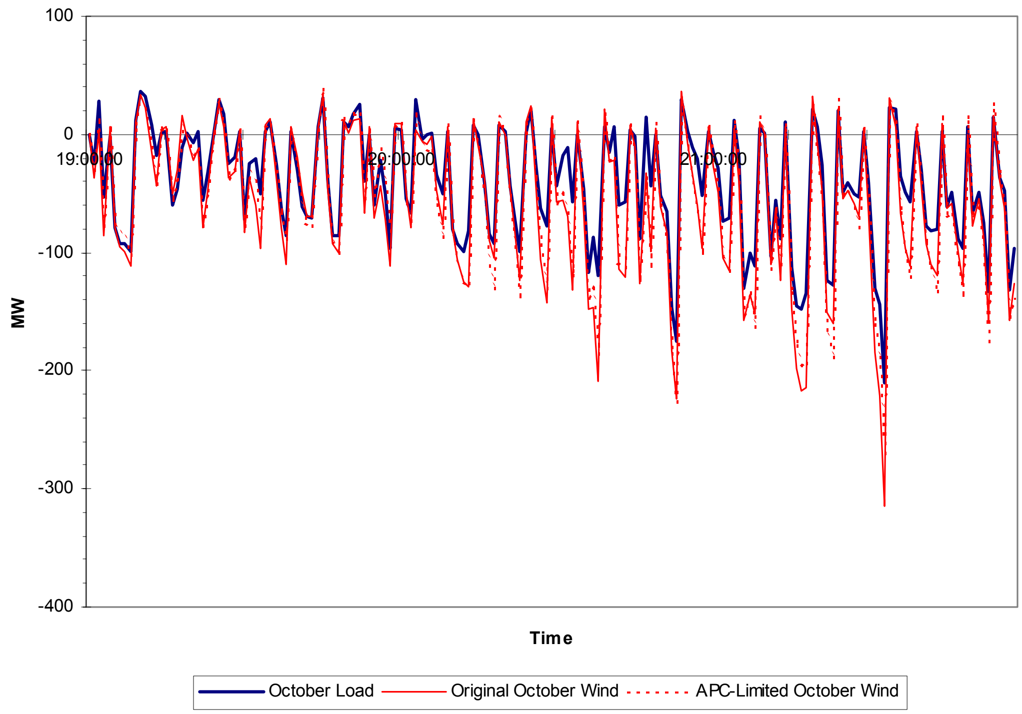

Figure 6.17 AGC Proxy Unit Output for October Study Scenarios with and without APC.

6.2 Stability Analysis

The data, methods, tools, models, assumptions, study scenarios and results for the stability analysis are described in the following subsections.

6.2.1 Approach

The objectives of the stability analysis were to identify the impact of significant wind generation on automatic generation control (AGC) performance, evaluate the impact of various farm-level functions (e.g., voltage regulation) and WTG technologies on system performance, and investigate system-wide transient stability performance. Therefore, two time frames of stability analysis were performed – long term (10-minute or 600 second) and traditional (10 seconds).

AGC performance was evaluated by applying selected 10-minute load or 10-minute load and wind generation profiles to the study system. The impact of wind farm voltage regulation was also evaluated in a 10-minute simulation.

Various farm-level functions (e.g., low voltage ride through), WTG technologies, and system-wide transient stability performance were evaluated in traditional 10-second stability simulations.

All New York generating unit, including all wind farm, variables were monitored in the stability analysis as well as selected internal interface flows, tie flows between New York State and its neighbors, and other case-dependent information.

Additional details of the stability analysis approach are discussed in the following subsections. The results are discussed in Section 6.2.2, *Results*.

6.2.1.1 Data

Three types of data were used in the stability analysis: power flow and dynamic databases, individual wind farm output profiles, and zonal load profiles. Each is described below.

6.2.1.1.1 Power Flow and Dynamic Databases

The three power flow databases provided by NYISO, representing peak, light, and intermediate New York State load levels without significant wind generation, were described in Section 6.1.1.1.1, *Power Flow Databases*. The light load case was used in the stability analysis, representing the system conditions shown in Table 6.3.

Table 6.3 Summary of Stability Power Flow System Conditions with No Wind Generation.

	Light Load
Total NY State Generation	14,514 MW
Total NY State Load	14,174 MW 5,797 MVAr

Power flows were also developed to represent the New York State system with the primary wind generation scenario, as described in Section 1, *Introduction*. Thirty-seven individual wind farms were added to each of the above databases. Each wind farm was connected via an appropriately sized transformer to a designated substation and represented by a single equivalent machine. The output of each wind farm was set by the selected wind profile. The total initial output from all 37 wind farms varied from about 600 MW to 2300 MW in the stability study. In general, the system redispatch required to accommodate wind generation was performed in the same zones in which the wind farms were added. This minimized the location-based impact of the wind generation and focused the evaluation on wind-specific issues, such as WTG performance, farm-level functions, etc.

Dynamic databases, corresponding to each power flow, were also provided by NYISO. These databases were augmented by the addition of an AGC model and WTG models, as needed. Unless otherwise noted, all WTG models were vector controlled, based on GE's 1.5MW WTG technology. All WTG models also included low voltage ride through (LVRT) capability sufficient to withstand 0.3pu voltage for up to 100 milliseconds, a reactive power output range of ± 0.436pu of maximum farm output, and voltage regulation. Remote (i.e., high side or transmission bus) regulation was implemented for all wind farms that did not share an interconnection bus. At transmission buses with multiple wind farm interconnections, local (i.e., low side or 34.5kV collector bus) regulation was implemented. Details of the dynamic WTG models are provided in Appendix D. Details of other dynamic models (e.g., AGC) are provided in Appendix E.

6.2.1.1.2 Wind Profiles

In addition to the 1-minute data used in the QSS analysis, AWS TrueWind also provided 1-second data for the stability analysis. A statistical analysis of that data is provided in Section 5.4.2, *One-Second Wind Variability*.

The 1-second data included six selected 10-minute intervals from different months and different times of day. Again, the data was provided in terms of power output (MW) by individual site. However, the wind turbine-generator (WTG) model used in the stability analysis requires wind speed as its input variable. Therefore, the power output data (MW) was converted to wind speed (m/s). To test the accuracy of the conversion, the calculated wind speed was used to drive a simulation and the resulting wind farm power output was compared to the original AWS TrueWind data. An example of this comparison is shown in Figure 6.18. The green trace represents the AWS power output (MW) data and the pink trace represents the power output (MW) resulting from a simulation using calculated wind speed as an input signal. The largest difference between input data and simulated results was approximately 0.5MW. This level of accuracy was deemed acceptable. Therefore, calculated wind speed was used as the input signal for the equivalent WTGs in the stability analysis.

As noted above, the data was provided with 1-second resolution. However, stability simulations use time steps on the order of 4 milliseconds. Therefore, a simple interpolation was performed to generate wind speeds between each 1-second data point.

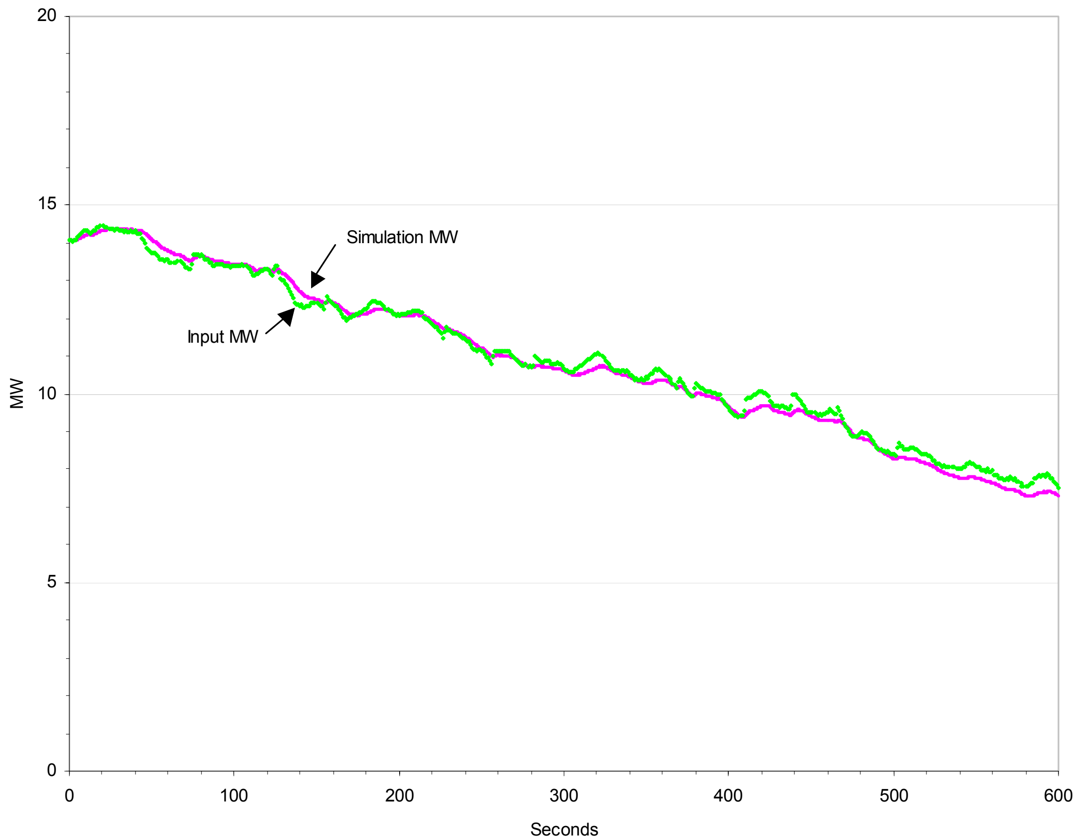

Figure 6.18 Wind Farm Power Output Comparison.

Additional information on the AWS TrueWind data is provided in Appendix A. Additional information on the wind turbine-generator model is provided in Appendix D.

6.2.1.1.3 Load Profiles

NYISO provided 6-second zonal load data (MW) for each day in January, April, August, and October 2003, as described in Section 6.1.1.1.3, *Load Profiles*.

The zonal load profiles were used to set the power level for all individual loads in New York State in the stability analysis. Specifically, a change in zonal load from one data point to the next was spread across all loads in that zone, proportional to the size of an individual load. In addition, a simple interpolation was performed to generate load levels between each 6-second data point.

6.2.1.2 Study Scenarios

The evaluation of AGC performance was performed on the light load database, using 10 minutes of 6-second load and 1-second wind profiles. The studied load (MW, blue line) and wind generation (MW, red line) profiles are shown in Figure 6.19. They represent part of an August morning with a total New York State 10-minute load increase of approximately 250 MW, and a total wind generation 10-minute decrease of approximately 150 MW. As the QSS analysis evaluated system performance for wind and load profiles with opposing trends, so did this part of the stability analysis. The same load and wind profiles were used in the evaluation of the impact of voltage regulation on system performance.

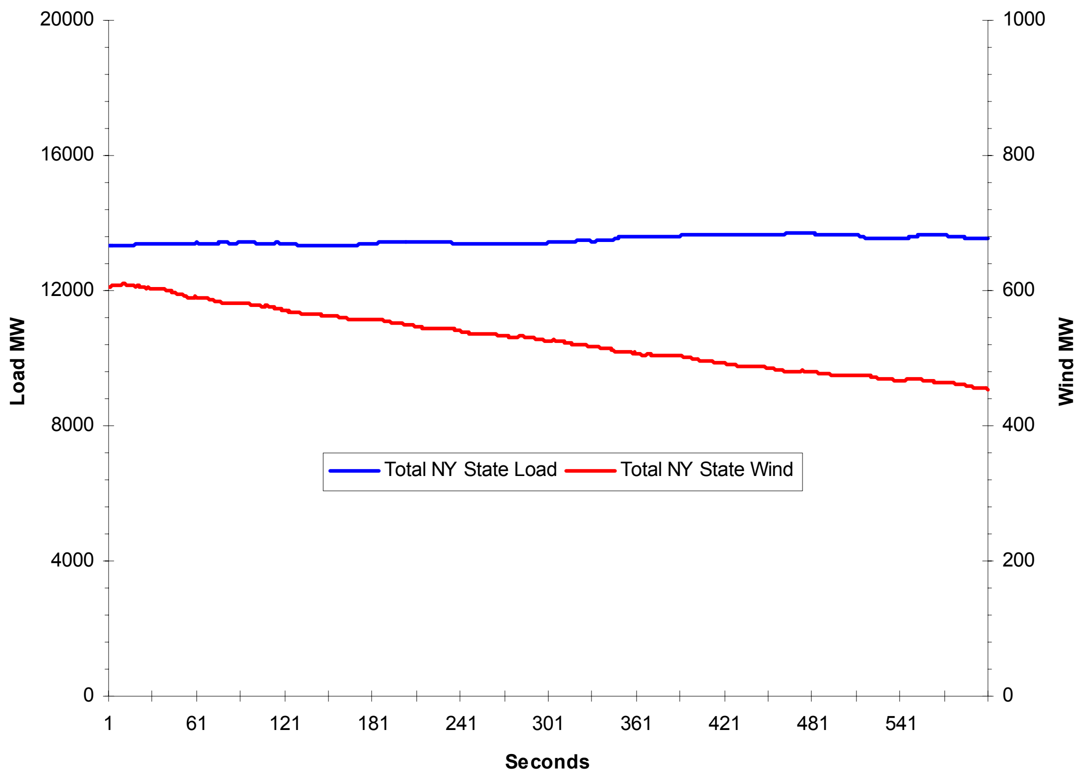

Figure 6.19 Wind and Load Profiles for 10-minute Stability Simulations.

The evaluation of other farm-level functions (e.g., LVRT), WTG technologies, and system-wide transient stability was also performed on the light load database, using a 3-phase Marcy 765kV fault and line clearing event as the test disturbance. The load levels and wind farm output levels were not modified during the course of these simulations.

6.2.2 Results

The discussion of the stability results is split into two subsections. Section 6.2.2.1, *Wind Farm Performance*, discusses the impact of various farm-level functions on system performance in the 1 to 10-second time frame, and Section 6.2.2.2, *System Performance*, discusses the impact of wind generation on overall system performance in the 10-minute time frame.

6.2.2.1 Wind Farm Performance

The impact of low voltage ride through (LVRT) capability, voltage regulation, and wind turbine generator technology differences on system performance are described in the following sections. The ability of wind farms to withstand frequency swings is also evaluated.

6.2.2.1.1 Overall Stability Performance

The transient stability behavior of wind generation is significantly different from conventional synchronous generation. The distinction is particularly acute for vector controlled wind turbine-generators[xiv]. Like conventional generators, wind turbine-generators will accelerate during system faults. However, unlike synchronous machines there is no physically fixed internal angle that must be respected in order to maintain synchronism with the grid, and which dictates the instantaneous power delivered by the machine to the grid. With WTGs, the internal angle is a function of the machine characteristics and controls, allowing a smooth and non-oscillatory re-establishment of power delivery following disturbances. The difference in behavior is similar to that of a automobile shock absorber: the WTG will respond to system events (potholes), but not rigidly transmit the effect of a disturbance between the turbine (passengers) and grid (road). These same characteristics also mean that WTGs will not contribute to system oscillations. The net result of this behavior is that wind farms generally exhibit better stability behavior than equivalent (same size and location) conventional synchronous generation.

To illustrate the difference, selected results of two Marcy fault simulations are shown in Figure 6.20. Specifically, the Marcy 345kV bus voltage (pu) and Total East interface flow (MW) are shown. The solid line represents a case with the 37 wind farms in-service, generating approximately 2280 MW. The dotted line represents system performance with no wind generation. Both the post-fault voltage dip and the oscillations in the interface flow are improved with the addition of vector controlled WTGs.

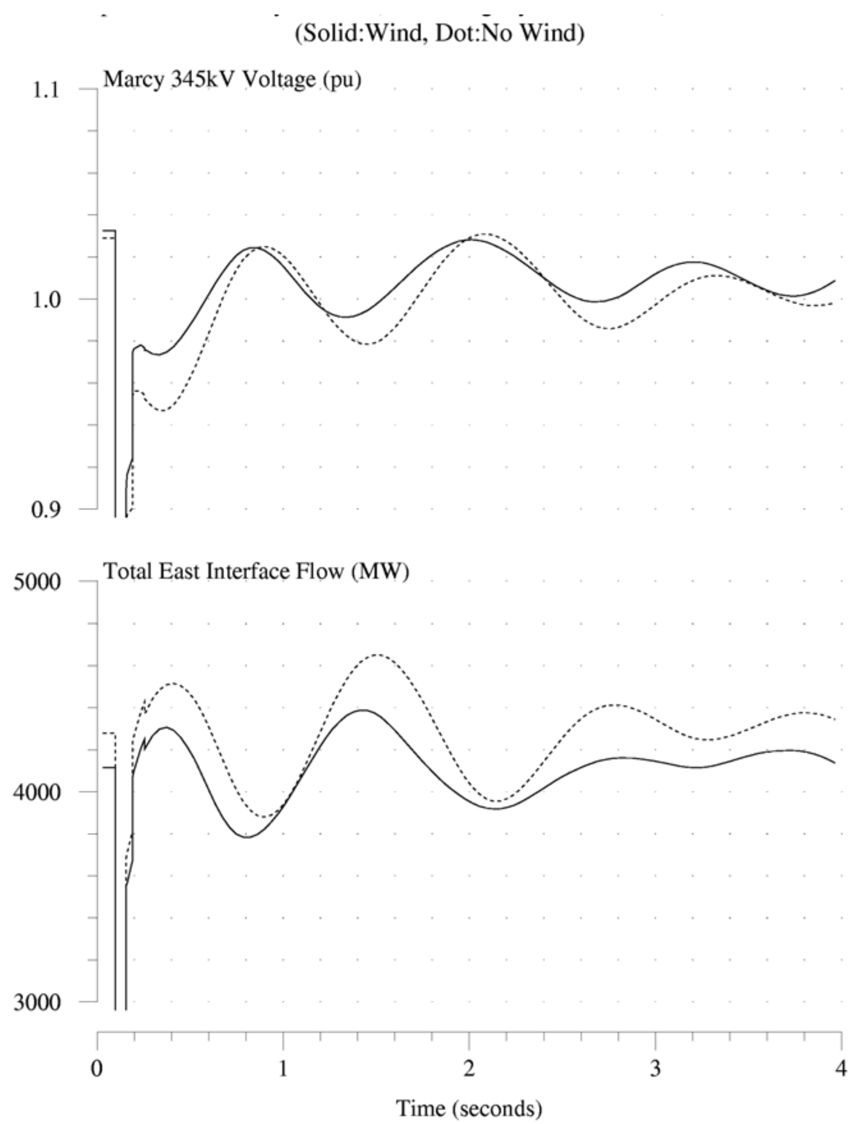

Figure 6.20 Impact of Wind Generation on System Performance.

6.2.2.1.2 Low Voltage Ride Through (LVRT)

Historically, the utility industry expected wind generation to trip in response to significant system disturbances. This expectation, and often requirement, was driven by the fact that wind generation constituted a small portion of the total generation resource pool, and most wind generation was sprinkled throughout distribution systems. These considerations are no longer applicable. Both the penetration of wind generation and the size of wind farms connected directly to the transmission grid have increased. In turn, a utility's exposure to significant simultaneous loss of wind generation in response to low voltages has also increased. Therefore, the ability of WTGs to tolerate momentary depressions in system voltage due to system faults is of significant concern to the utility industry. This capability is variously called “fault ride-through,” “low voltage ride-through” (LVRT), and “emergency voltage tolerance.” Therefore, the impact of LVRT on both system and farm-level performance was evaluated in this study.

As noted in Section 6.2.1.1.1, *Power Flow and Dynamic Databases*, the selected LVRT function allowed WTGs to withstand a 0.3pu voltage for up to 100 milliseconds. Note that the industry is moving toward a more aggressive LVRT requirement in terms of both minimum voltage and timer thresholds.

Selected results of two Marcy fault simulations are shown in Figure 6.21. Specifically, the Marcy 345kV bus voltage (pu), Total East interface flow (MW), and Site 6 wind farm power output (MW) are shown. The solid line represents a case with the 37 wind farms in-service, generating approximately 2280 MW, with LVRT capability on all farms. The dotted line represents the same wind generation scenario but without LVRT capability. There is no significant difference in system-wide voltage or interface flow performance with or without LVRT capability.

However, it can be observed that without LVRT, the wind farm trips when the interconnection bus voltage dips below 0.7pu, resulting in a loss to the system of approximately 300MW of generation. With LVRT, this wind farm remains connected to the system. NYS performance criteria do not allow tripping of remote generation for design criteria faults. Only local generation that is included in the fault may trip.

In addition, the loss of generation associated with the lack of LVRT could be significant under severely stressed system conditions or in response to more severe fault disturbances. The distribution of terminal voltages observed at each wind farm in response to the Marcy fault is shown in Figure 6.22. The blue dots represent the minimum terminal voltages at each site. The red line shows the voltage tripping threshold (0.7pu) for WTGs without LVRT and the yellow line shows the voltage tripping threshold (0.3pu) for WTGs with the LVRT used in this analysis. Note that Sites 6 and 25 are the only two sites with low enough voltages to trip without LVRT. The green line represents the voltage tripping threshold (0.15pu) which appears to be the consensus emerging from on-going industry-wide discussions. It is recommended that NYS adopt the emerging LVRT specification.

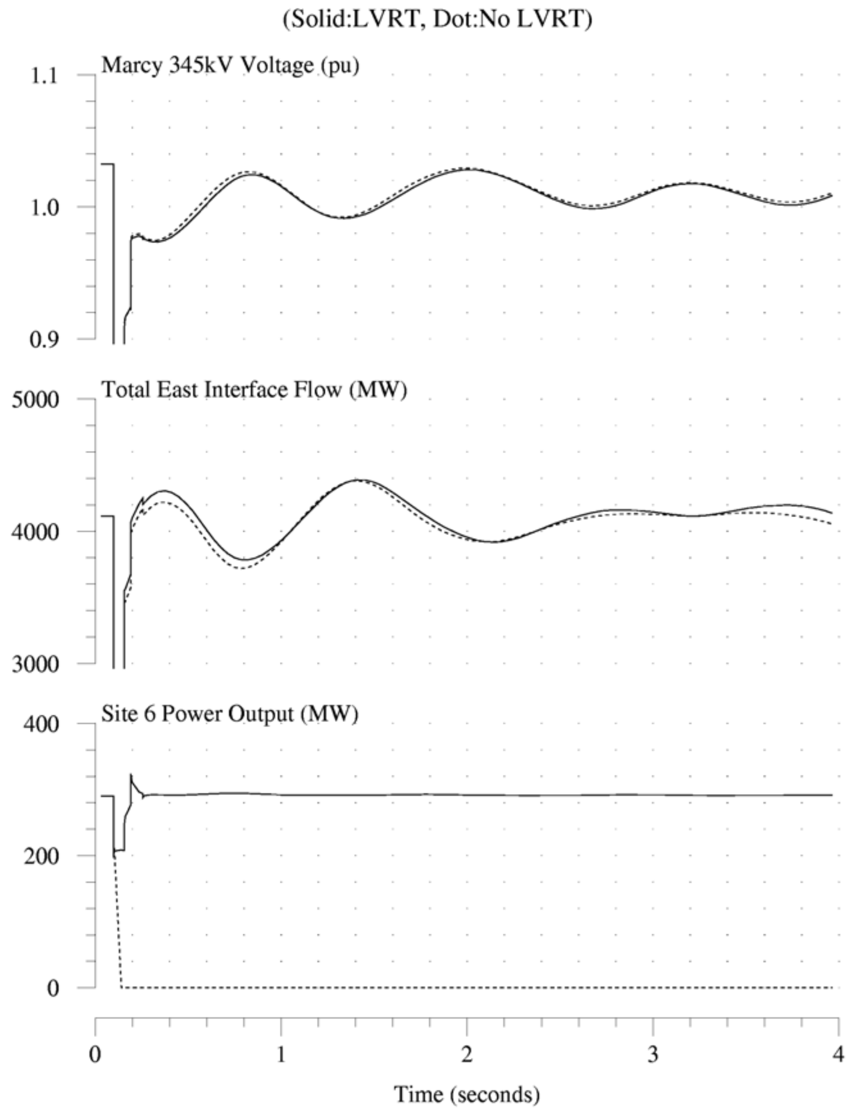

Figure 6.21 Impact of LVRT on System Performance.

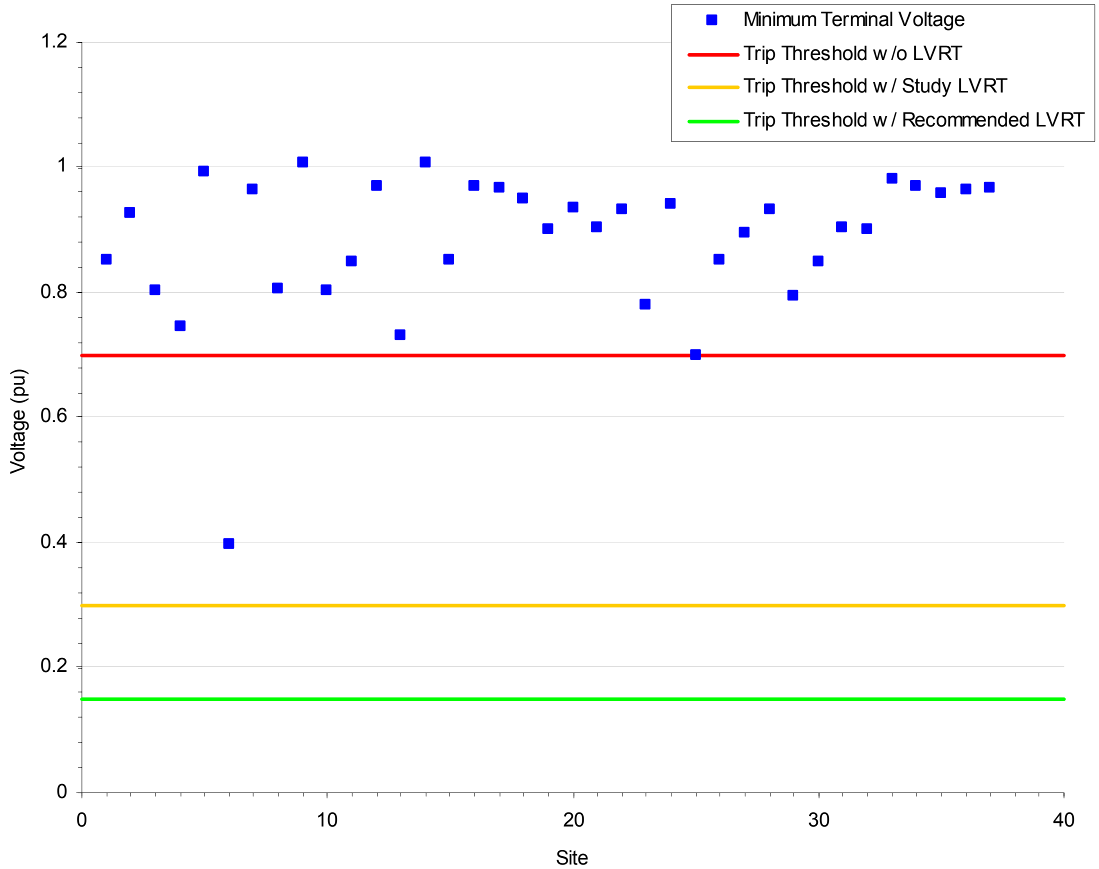

Figure 6.22 Minimum Terminal Voltages for All Wind Farms in LVRT Example.

6.2.2.1.3 Voltage Regulation

The ability of individual WTGs and entire wind farms to regulate voltage varies. Historically, WTGs with induction generators were not required to participate in system voltage regulation. Their reactive power demands, which increase with active power output, were typically compensated by switched shunt capacitors. This compensation was somewhat coarse, in that the capacitors are switched in discrete steps with some time delay. Therefore, many large wind farms, particularly those with interconnections to relatively weak transmission systems, are now designed to provide voltage regulation. These farms include supervisory controllers that instruct components of the wind farm (WTGs, shunt capacitors, etc.) to regulate voltage, usually at the POI (point of interconnection), to a specified level. Many new wind farms also accept a reference voltage that is supplied remotely by the system operator.

Of these various types of WTGs, only vector controlled WTGs have the inherent ability to control reactive power output from the generator, and therefore to regulate voltage. For the other WTGs, additional equipment is required to compensate for the generator's reactive power consumption and to meet the reactive power needs of the host grid. In applications on relatively weak systems, the addition of fast-acting solid-state reactive power equipment may be required to meet the voltage regulation requirements with these other types of WTGs. In general, however, fast and tight voltage regulation is possible with any properly designed wind farm.

Therefore, the impact of voltage regulation on system performance was evaluated in this study by comparison to reactive power regulation. Voltage regulation is achieved by a closed loop adjustment to the reactive power order. The reactive power control is achieved by a closed loop adjustment of reference voltage, and is effectively regulating to near unity power factor. This is only one example of a reactive power control.

The results of two Marcy fault simulations, with and without voltage regulation, are shown in Figure 6.23. The left column shows selected wind farm variables at a particular site with voltage regulation, and the right column shows the same variables at the same site with reactive power regulation. The top row of plots show wind farm terminal bus voltage (pu, solid line) and reference voltage (pu, dotted line). The second row of plots show wind farm reactive power output (MVAr, solid line) and reactive power reference (MVAr, dotted line). The results with voltage regulation show a fast recovery and that the minimum post-fault terminal bus voltage is greater than 1.00pu. With reactive power regulation, the recovery is slower and the minimum post-fault terminal bus voltage is about 0.92pu. The reactive power output, however, is regulated to its reference. Other reactive power control schemes are possible, and would have a similar impact on system performance.

Long term stability simulations, 600 seconds in duration, were also performed with and without voltage regulation. Instead of a fault disturbance, the simulation was driven by selected August load and wind profiles.

The impact of voltage regulation on Adirondack 230kV bus voltage performance is illustrated in Figure 6.24. The solid line (top) represents voltage regulation, the dotted line (bottom) represents reactive power regulation, and the dashed line (middle) represents system performance without wind. Note the drift in bus voltage with reactive power regulation as well as in the case without wind. The addition of wind farms with voltage regulation capability improved the transmission system voltage profile.

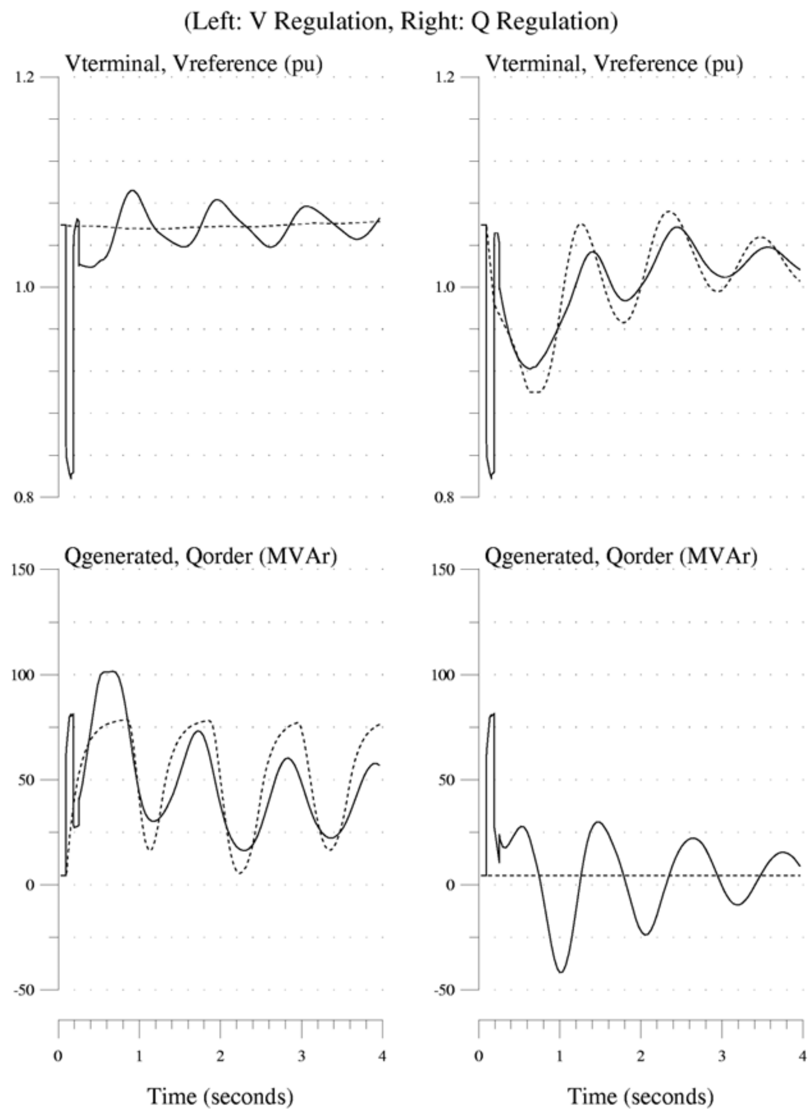

Figure 6.23 Local Performance with and without Voltage Regulation.

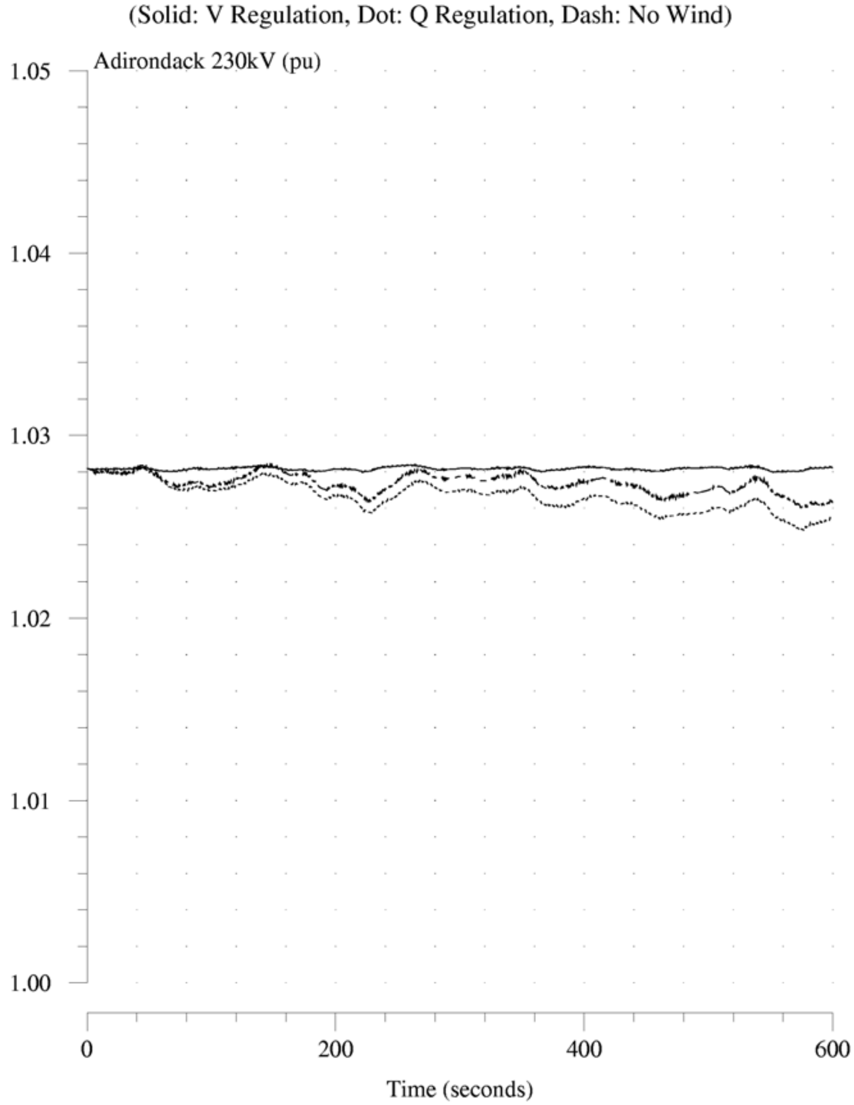

Figure 6.24 System Performance with and without Voltage Regulation.

6.2.2.1.4 Wind Turbine-Generation Technology

As noted in the "Technical Characteristics"[xv] document, the type of WTG technology can have a significant impact on system performance. As noted in Section 6.2.1.1.1, *Power Flow and Dynamic Databases*, the bulk of this study was performed using vector controlled WTG models. To illustrate the different levels of performance inherent in the different types of WTG technology, additional fault simulations were performed. The response of vector controlled WTGs was compared to stall regulated WTGs to bracket performance. Scalar controlled WTG performance would fall in between that of the other two types of WTG. Therefore, it was not evaluated for this study. Details of the dynamic models are provided in Appendix D.

The impact of WTG technology on Marcy 345kV bus voltage performance is illustrated in Figure 6.25. The solid line represents vector controlled WTG performance and the dotted line represents conventional stall regulated WTG performance. The post-fault voltage was about 2% lower with the stall regulated WTGs.

The impact of WTG technology on an individual wind farm is illustrated in Figure 6.26. Selected variables for one wind farm site are shown. Again, the solid line represents vector controlled WTG performance and the dotted line represents stall regulated WTG performance. Real power output (MW), reactive power output (MVAr), and terminal bus voltage (pu) are shown. With the stall regulated WTG, reactive power consumption is significant, real power output is not maintained and the terminal voltage recovery is slow. By contrast, vector controlled WTGs maintain real power output and provide fast voltage recovery. The reactive power output, which moves in response to overall system oscillations, is also reduced. Note the significant difference in terminal voltage. It drops below 0.90pu with the stall regulated WTG, but remains above 1.00pu with the vector controlled WTG. Some improvement in stall regulated WTG performance could be achieved with the application of dynamic var compensation equipment.

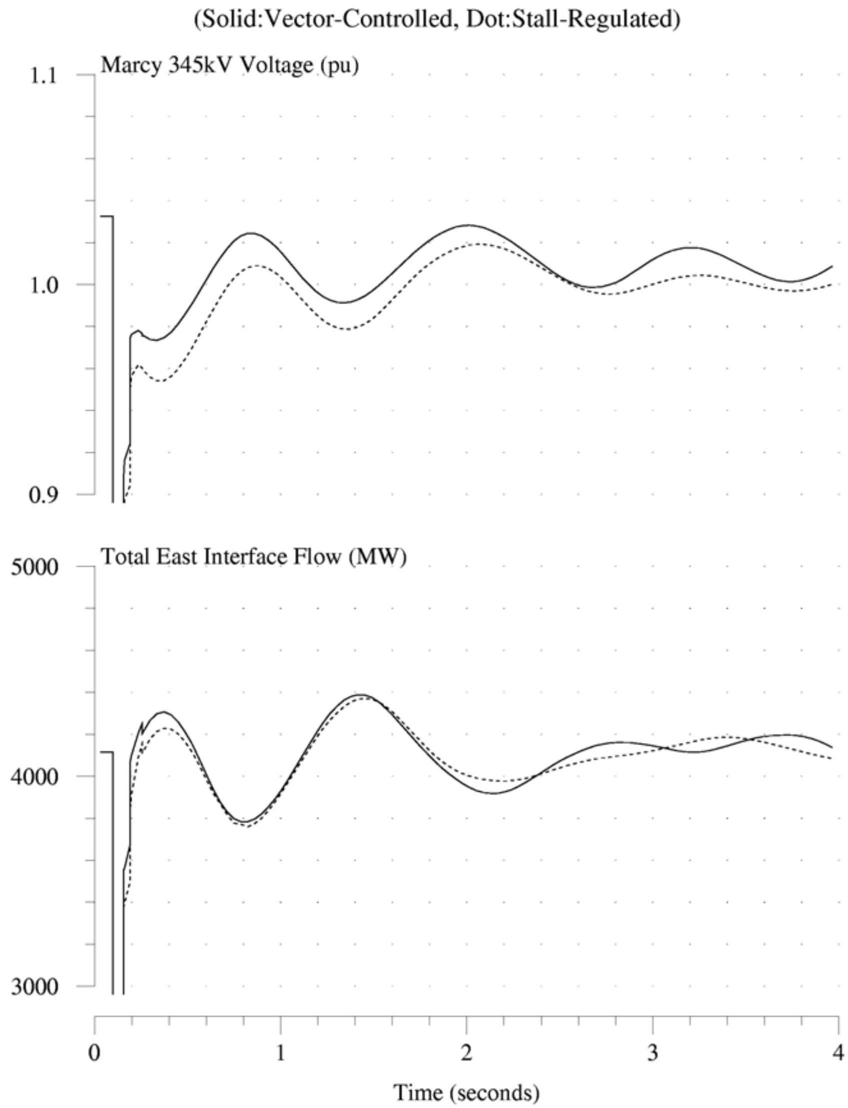

Figure 6.25 System Performance with Different Types of WTGs.

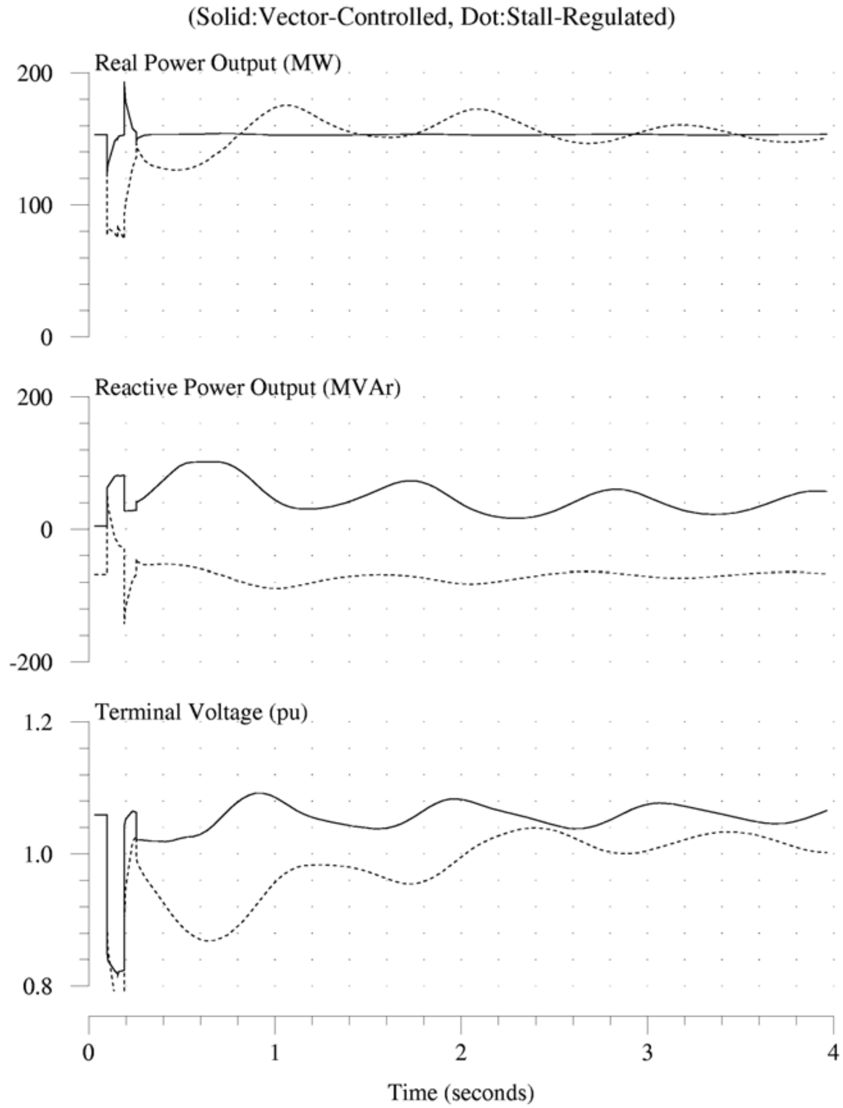

Figure 6.26 Local Performance with Different Types of WTGs.

6.2.2.1.5 Frequency Response

NPCC requires generating units to meet specific frequency performance criteria. NPCC Document A-5 *Bulk Power System Protection Criteria* states that "generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system", which implies that over- and/or under-frequency protection should not operate for fault disturbances that result in a stable system response. NPCC Document A-3 *Emergency Operation Criteria* identifies a specific under-frequency region in a frequency vs. time curve for which generating units are not allowed to trip. This document does not specify an over-frequency requirement.

A fault resulting in the loss of significant generation was used to test system response to frequency excursions, with and without wind generation. The test fault was applied at the Scriba 345kV bus and resulted in the trip of the 9 Mile Pt 2 unit for a loss of approximately 900MW of generation. The response of a selected wind farm (Site 6) is shown in Figure 6.27. The solid line represents system performance with wind generation, and the dotted line represents system performance without wind generation. Interconnection bus frequency (Hz) and interconnection bus voltage (pu) are shown. The frequency excursions are similar, with and without wind generation, but the voltage recovery is faster with the wind generation. The key point, however, is that no wind farms trip in response to these stable frequency swings.

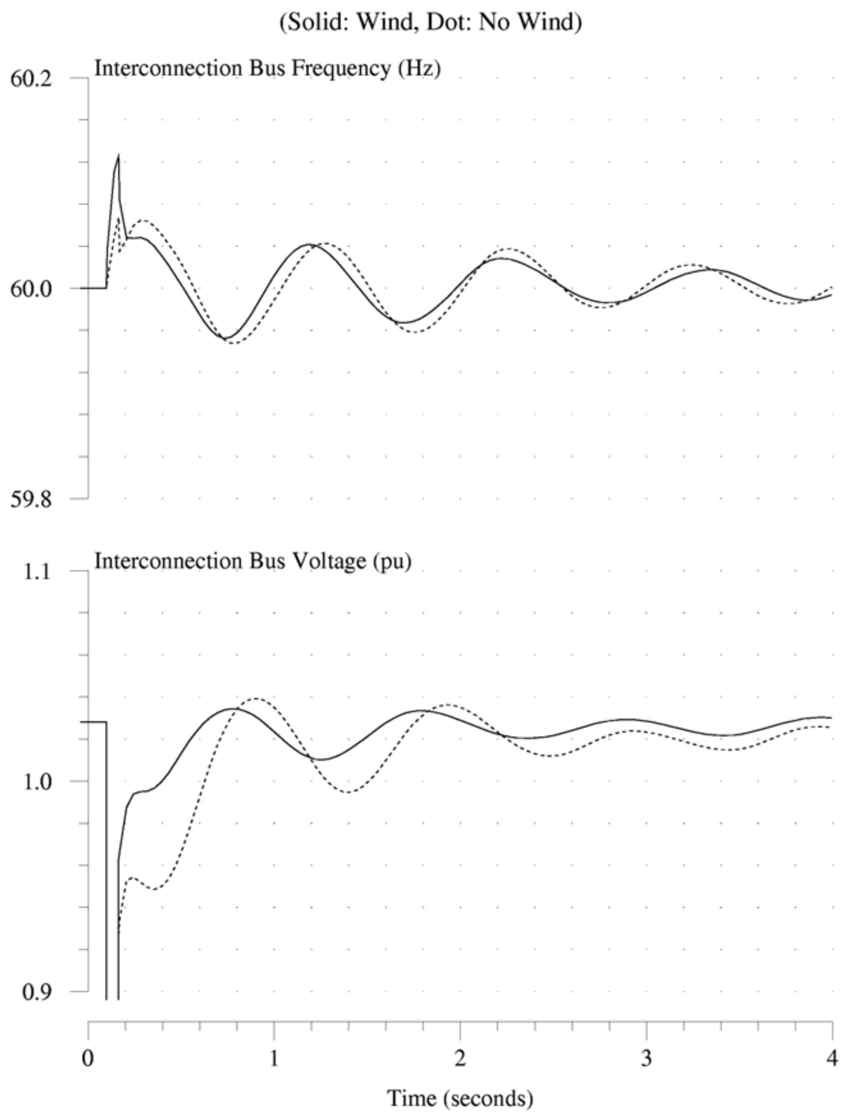

Figure 6.27 System Response to Frequency Swings with and without Wind Generation.

6.2.2.2 System Performance

The impact of significant amounts of wind generation on system-wide performance is discussed in this section. Specifically, long-term (10-minute) automatic generation control (AGC) performance was evaluated.

The objective of an AGC is to maintain 1) system frequency and 2) tie flows between control areas. For this analysis, NYISO's AGC was approximated with the model shown in Appendix E. Long-term stability simulations (600 seconds) were performed to evaluate the impact of wind generation on AGC performance. Specifically, the objective was to determine any increase in regulation requirements due to the addition of wind generation to the New York system. The benchmark case tested AGC response to an August morning load rise. The comparison case tested AGC response to the combination of an August morning load rise and an August morning wind generation decrease.

Figure 6.28 shows selected system and AGC variables. The solid line represents system response to both the August morning load and wind profiles and the dotted line represents system response to only the August morning load profile. The top plot shows New Scotland 345kV bus frequency (Hz). The second plot shows total New York State load (MW), which is the same in the two cases. The third plot shows the area control error (ACE), which is the difference between scheduled tie flow and actual tie flow plus a frequency bias component. The fourth plot shows the area tie flow (MW), which is the sum of the power flow on all ties between New York State and its neighbors. The bottom plot shows the total output of all New York generating units controlled by the AGC (MW).

The frequency trace shows that the AGC is meeting its objective to maintain frequency. The somewhat fuzzy nature of this trace is due to the numerical differentiation and plotting interval. There is little difference between the bus frequency with and without wind generation.

Note that the addition of wind generation has changed the area tie flows and therefore the ACE. In addition, the load following requirement has also increased. Following standard stability analysis practice, no economic redispatch or unit commitment changes were made during the course of the simulation. Therefore, all of the load following was performed by the units on AGC. As a result, the units under AGC control are generating more power with wind than without wind. At the end of the simulation, the difference in total output of the AGC units is approximately 150 MW. This overall rise in AGC output is conservative, as a realistic generation schedule based on an economic dispatch would offset the load following component. Therefore, as long as load following units meet their objectives, the AGC units will see similar duties, with or without wind generation.

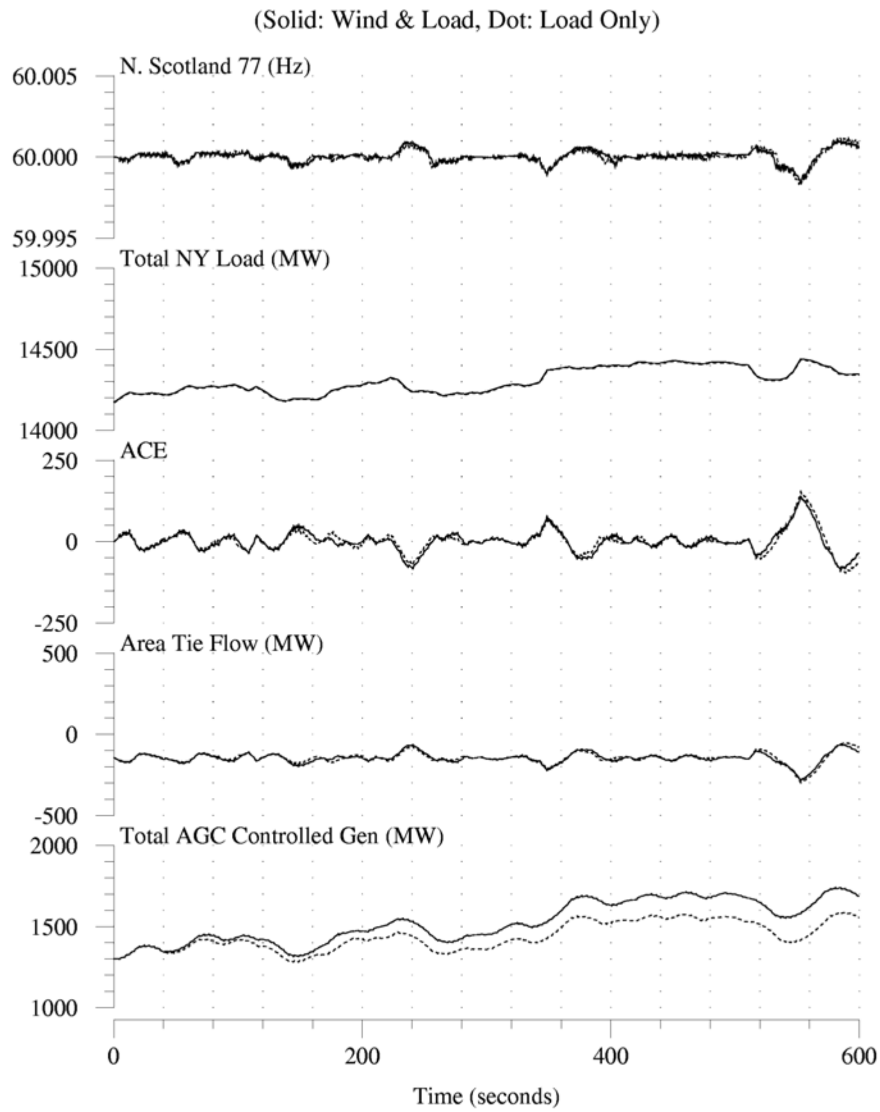

Figure 6.28 AGC & Frequency Response to August Load and Wind Profiles.

6.3 Conclusions

The QSS and stability time simulations discussed in this section were representative illustrations of system performance, intended to provide context for the statistical analysis presented in Section 5, *Wind and Load Variability*. The simulations illustrated the impact of significant amounts of wind generation on the New York State power system's load following capability, regulation requirements and overall transient stability. In addition, the performance of selected farm-level functions (e.g., LVRT, voltage regulation, WTG technology, active power control) was illustrated.

The study scenarios were selected to be severe, but likely, tests of the operational impacts of significant amounts of wind generation on New York State system performance. The QSS results, as well as the statistical analysis performed in Section 5, *Wind and Load Variability*, show that 3,300 MW of wind generation will impose additional load following duty on the economically dispatched units. No change in unit commitment is anticipated, but some of the load following may be performed by sub-economic units to respect the 1%/minute load following capability of individual units. The required load following duty appears to be within the capability of the existing system.

The results of the long-term stability analysis showed that the addition of wind would have little impact on the second-to-second response of the AGC. Therefore, as described in Section 5.4.1, *AGC Performance*, NYISO's existing level of regulation should be adequate with the addition of 3,300 MW of wind generation.

As described in Section 6.2.2.1.1, *Overall Stability Performance*, the transient stability behavior of wind generation, particularly vector controlled WTGs, is significantly different from that of conventional synchronous generation. The net result of this behavior difference is that wind farms generally exhibit better stability behavior than equivalent (same size and location) conventional synchronous generation.

Phase 1 of this project recommended that New York State require all new wind farms to have certain features. The impact of the two selected features, voltage regulation and low voltage ride through (LVRT), on system performance was demonstrated in this section. Voltage regulation improves system response to disturbances, ensuring a faster voltage recovery and reduced post-fault voltage dips. LVRT ensures that wind farms remain connected to the NYSBPS under low voltage conditions due to faults or other system disturbances. Therefore, the Phase 1 recommendations are substantiated by the simulation results described in Sections 6.2.2.1.3, *Voltage Regulation,* and 6.2.2.1.2, *Low Voltage Ride Through (LVRT)*.

Good performance was demonstrated with LVRT parameters that are less aggressive than the emerging industry consensus. However, only a single illustrative simulation was performed. The studied LVRT parameters may not be sufficient to provide acceptable performance in response to more severe faults or under more stressed system conditions. Therefore, it is recommended that

NYS adopt the emerging LVRT specification. That specification appears to be converging on the E-ON Netz based requirement of 15% retained voltage at the point of interconnection for 625 milliseconds, rising linearly to 90% retained voltage at 3 seconds as shown in the FERC NOPR on wind generation interconnection requirements[xvi]. The FERC NOPR also allows a wind farm to request a waiver on the LVRT requirement and the transmission provider to agree to the waiver, under certain conditions. New York may also decide to adopt this policy.

Phase 1 also identified other farm-level functions that should be considered by New York State as potential future requirements. Of these, the ability to set power ramp rates for wind farms was demonstrated in Section 6.1.2.3, *Active Power Control*. The example ramp rate limit function resulted in a decrease in regulation requirements at the expense of energy production. To minimize the associated economic losses, such a function should only be used in specific applications to ensure system reliability. Again, the Phase I recommendations are substantiated by the simulation results shown in this section.

This page intentionally left blank.

7 Effective Capacity

7.1 Introduction

This section examines the effective capacity of wind generation. Typical thermal generation can supply capacity on demand, 24 hours a day, all week long. A 100 MW unit can provide 100 MW of capacity whenever called upon. Even recognizing generator forced outages has a predictable outcome since the outages are assumed to be random throughout the year. Therefore, if a 100 MW unit has a 10% forced outage rate, then there is a 90% probability that the unit will be available whenever it is called upon and its UCAP, or Unforced CAPacity, would be 90 MW as opposed to its ICAP, or Installed CAPacity, of 100 MW.

While a wind turbine may be expected to have a 30% capacity factor for the year, it would NOT be proper to view that as a 70% forced outage rate since the outages are NOT random. There is a definite seasonal and diurnal pattern to the wind output, and how this wind output aligns with the system demand will have a significant effect on its capacity value.

Historical NYISO load data for 2001, 2002 and 2003 was used for the analysis in this section. Wind outputs were also developed for 3,300 MW of installed capacity spread out across 33 sites on the system. The wind output was developed from historical meteorological data for the same years. In order to capture the correlation of loads and wind output, if any, all analysis used this time-synchronized data from corresponding years.

7.2 Wind and Load Shapes

Figure 7.1 shows the average monthly capacity factor for the 3,300 MW of wind turbines examined for the years 2001 through 2003. While some months approached 50%, the summer months, during the NYISO peak loads, were as low as 20%. The annual average capacity factor was roughly 30%. Figure 7.2 shows the average daily profile for the same time frame. The hours from 10 a.m. to 6 p.m. have less than a 25% capacity factor while the evening and nighttime hours may be greater than 40%. Figure 7.3 shows the seasonal wind shapes for 2002. The average capacity factor in the summer is 23% for the entire day and only 13% for the 10 a.m. to 6 p.m. time frame.

Figure 7.4 shows the average NYISO loads and wind output for the months of July, August and September 2001. The load and wind shapes are almost completely out of phase with each other.

The primary benefit of wind generation occurs late in the day when the wind output is picking up before the loads have fully dropped off. Figure 7.5 shows a similar trend for the 2002 data.

The scatter plots in Figure 7.6 and Figure 7.7 show another way of comparing the annual correlation of the wind output and system load. If the wind were randomly distributed across the year then the plots would show a uniform density between the minimum and maximum loads. However, the upper right quarter of the plots, which represent the simultaneous occurrence of high load and high wind generation output, are particularly sparse.

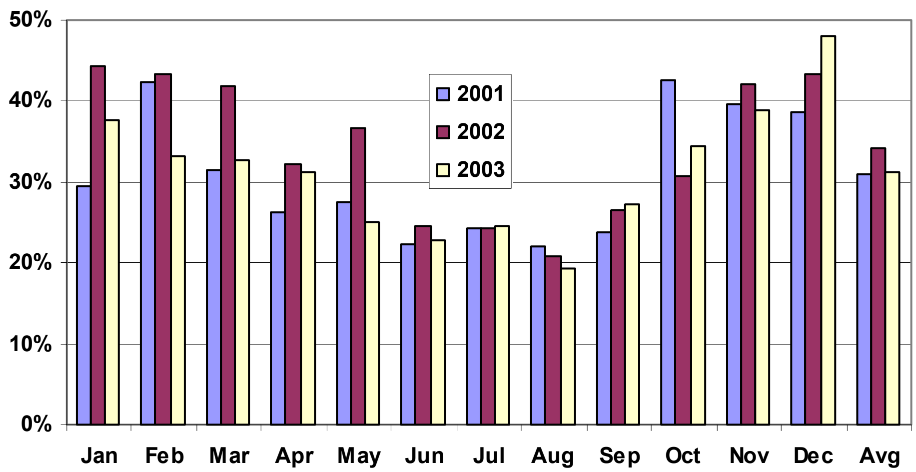

Figure 7.1 Monthly Wind Capacity Factors

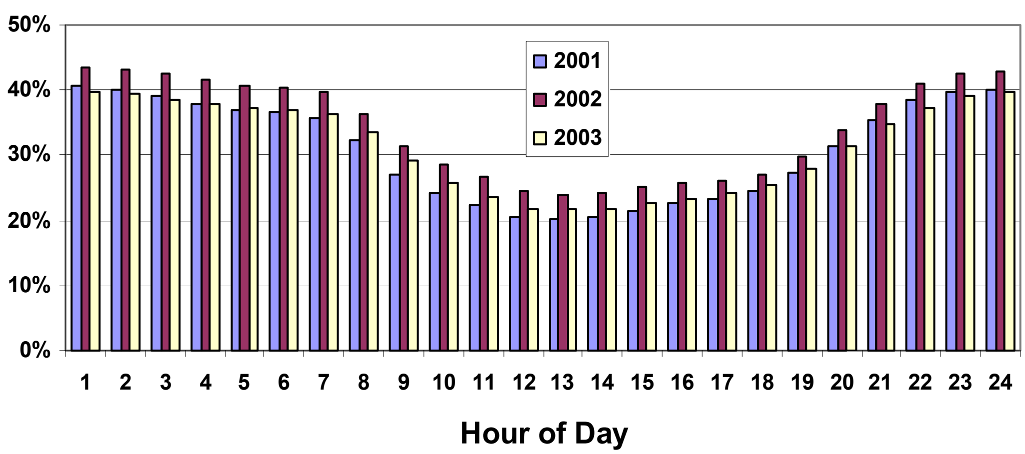

Figure 7.2 Hourly Wind Capacity Factors

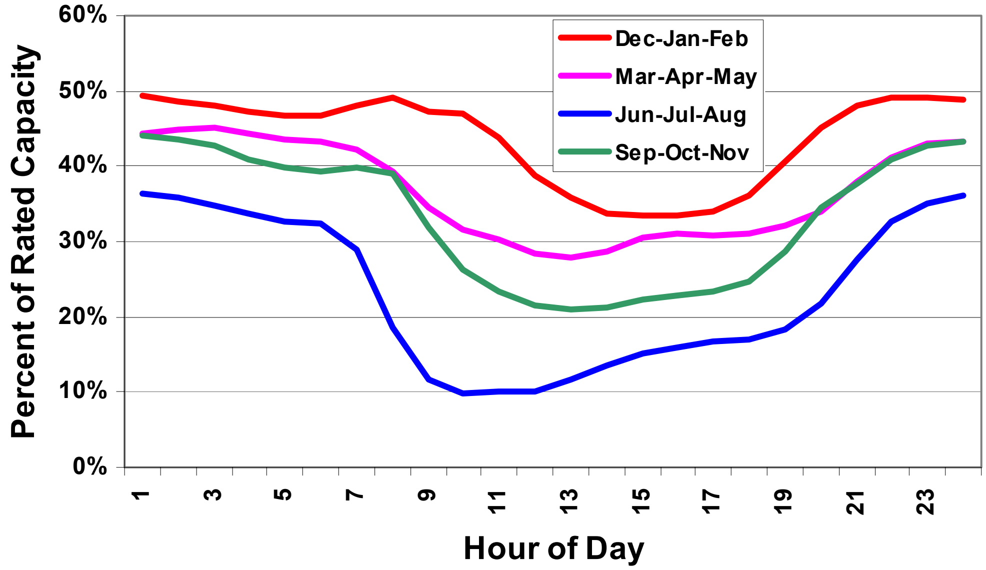

Figure 7.3 Average Seasonal Wind Shape, NYISO 2002

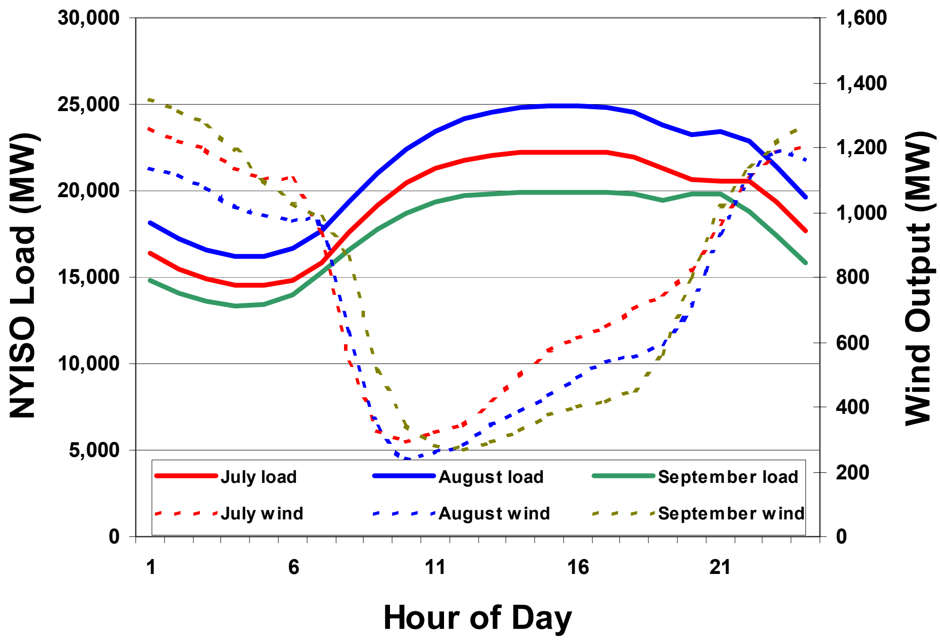

Figure 7.4 2001 Average Load versus Average Wind

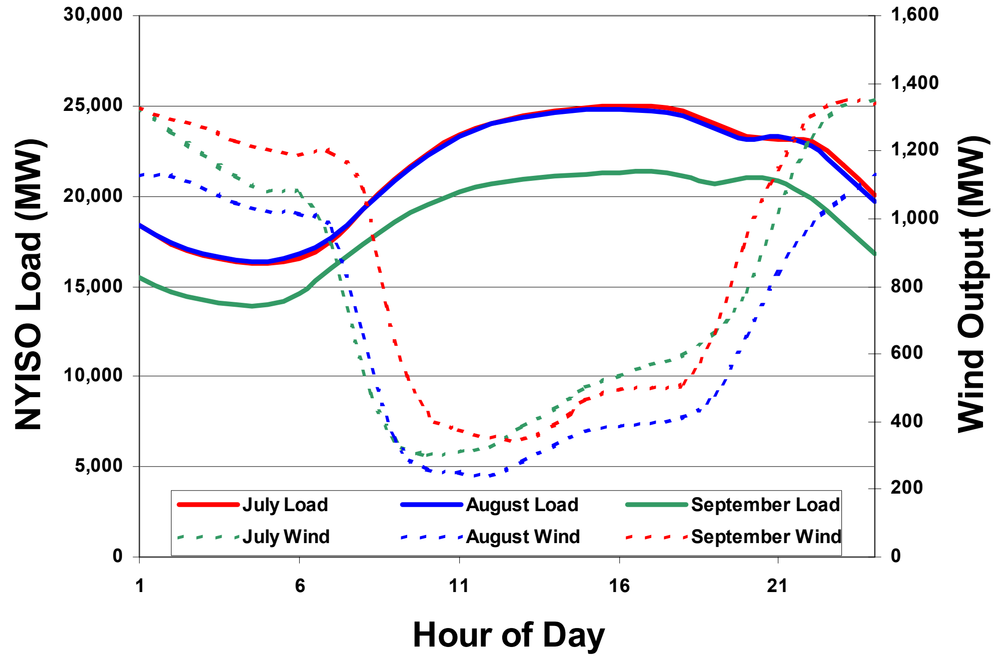

Figure 7.5 2002 Average Load and Average Wind

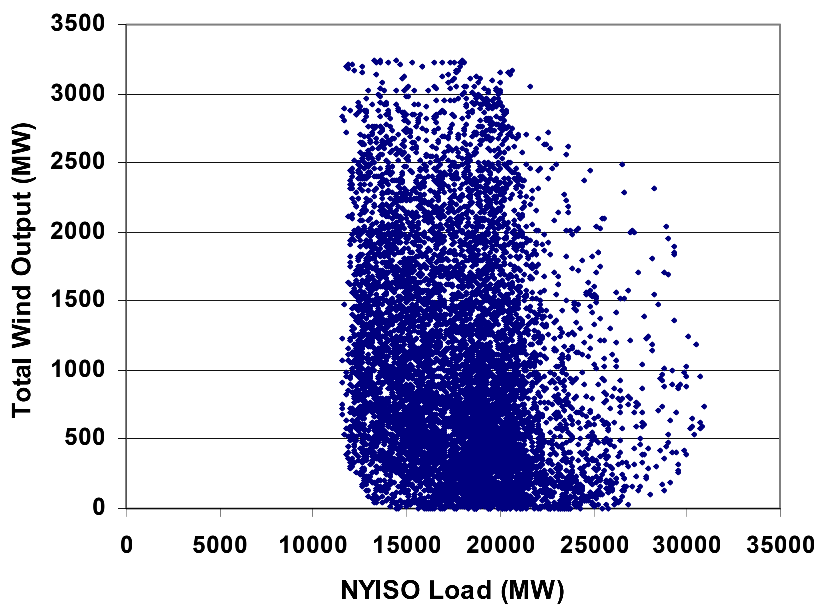

Figure 7.6 2001 Annual Load versus Wind Scatter Plot

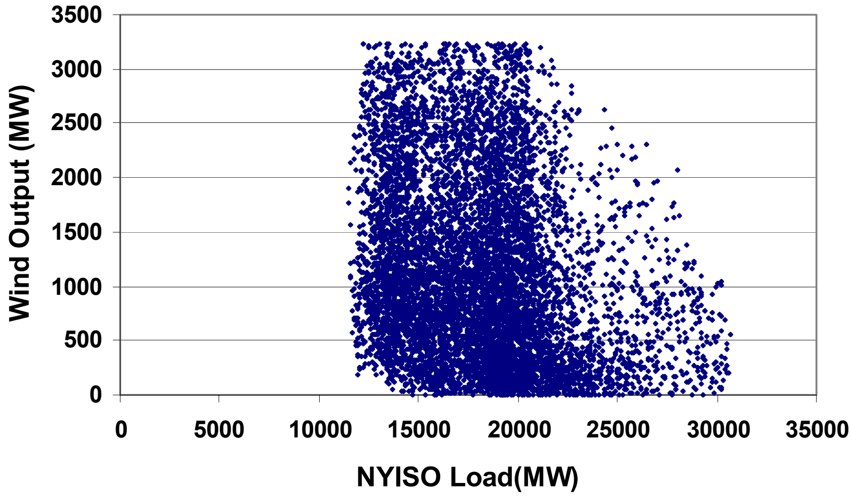

Figure 7.7 2002 Annual Load versus Wind Scatter Plot

The scatter plots in Figure 7.8 and Figure 7.9 show load versus wind for July and August of 2002. While these plots are somewhat more uniform in appearance it is important to note that there are few wind outputs above 2,500 MW even though the gross rating of all of the wind farms is 3,300 MW. Also, the plots are more dense below 1,000 MW of wind output than above.

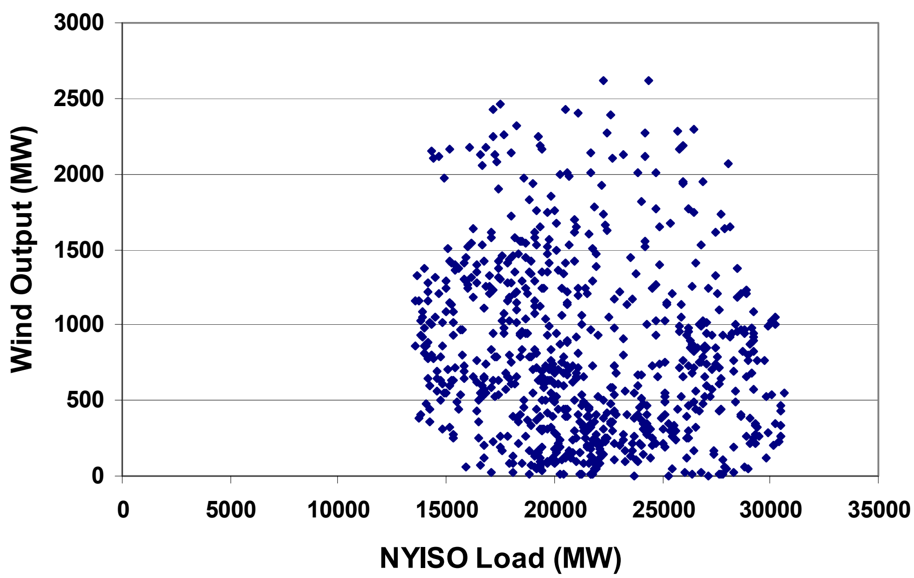

Figure 7.8 July, 2002 Load versus Wind Scatter Plot

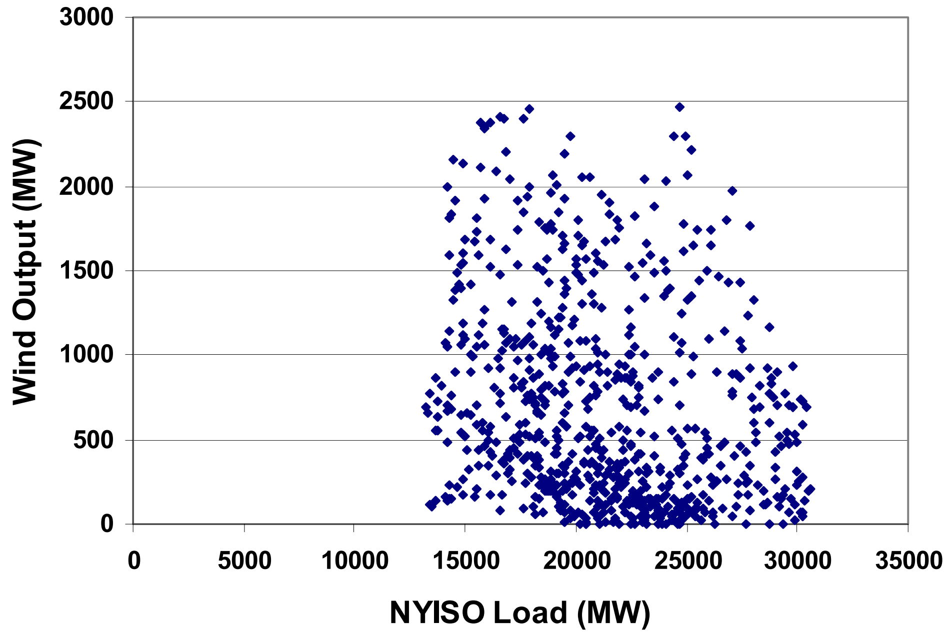

Figure 7.9 August, 2002 Load versus Wind Scatter Plot

Figure 7.10 shows the wind output and NYISO load for all of the days in July 2001. Although the wind occasionally exhibits higher values earlier in the day, most of the high wind output occurs during nighttime hours.

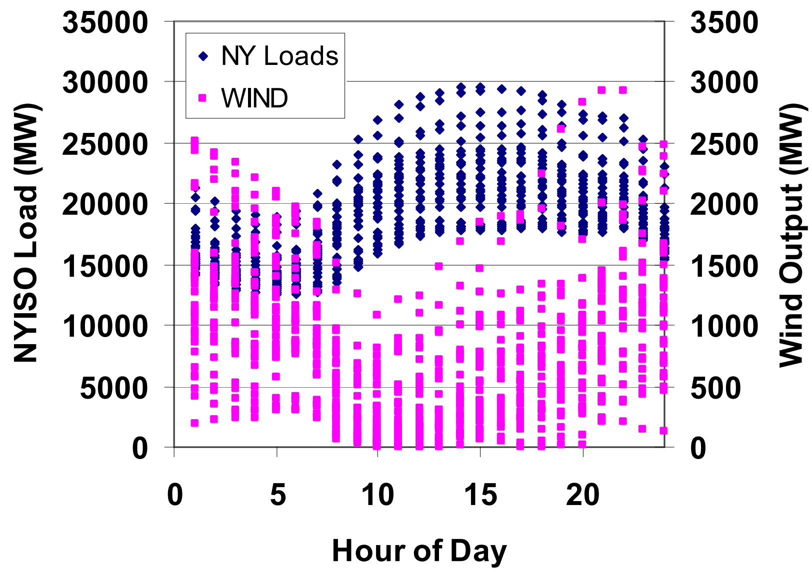

Figure 7.10 July 2001 Wind and Load versus Time-of-Day

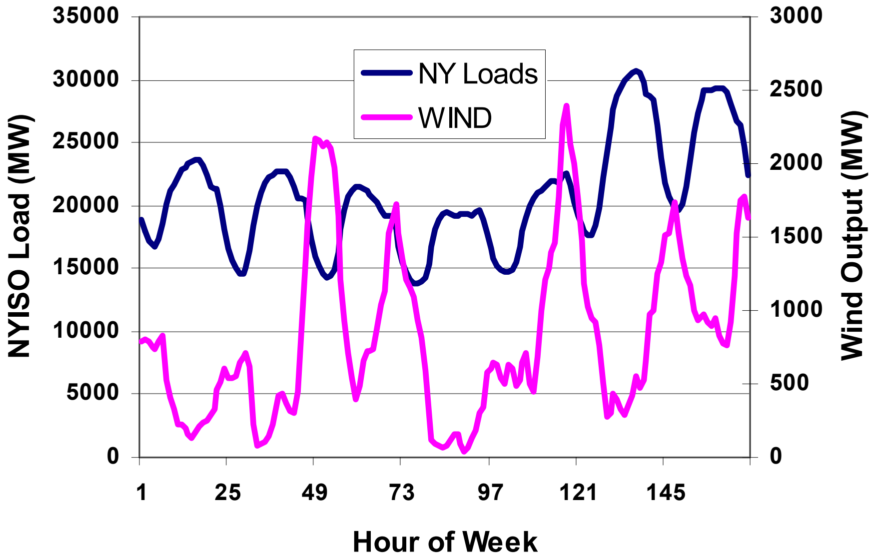

Figure 7.11 July 2002 Peak Week Wind and Load

Figure 7.11 shows the NYISO load and wind output for the peak week of July 2002. Although the wind generation reaches about 2,400 MW this week, its value at the time of the peak load is only about 500 MW.

7.3 LOLP analysis

The preceding analysis of daily and seasonal wind shapes illustrates how wind shapes correlate with loads. This section presents results of a standard Loss of Load Probability, LOLP, analysis on the system. The General Electric Multi-Area Reliability Simulation, MARS, program was used with the data from the NYISO's Installed Capacity Requirements study for May 2004 through April 2005. The peak loads were modified to represent the 2008 system. No additional generation was added since the existing system met the design targets of providing the New York Control Area, NYCA, with roughly 0.1 days/year Loss of Load Expectation (LOLE) on an interconnected basis. The 2001 and 2002 historical zonal load shapes were used along with the corresponding meteorological data to generate the output from the wind generation. *Note: the terms LOLP and LOLE are used interchangably throughout the industry to refer to the "Loss of Load" reliability index. That practice will be continued in this section. Historically the "Probability" term was applied, but purists argued that it is actually an "Expected" value. Either is acceptable.*

7.3.1 2001 and 2002 Analysis

Figure 7.12 shows the overall impact of the wind generation on the system LOLP. For each year of data, the system was first examined without the wind generation present. Although the analysis was performed using the 2008 peak load and energy projections the use of the historical 2001 or 2002 load curves caused a difference in the initial system risk levels. The 2002 load shape had more days with loads closer to the peak load than in 2001, causing the initial risk to be about 0.15 days per year in 2002 while it was only 0.05 days per year in 2001. This compares with the risk level of 0.11 days per year seen in the Phase 1 analysis of this study, which had used the 1995 historical load shapes. As a side note, recent studies by the NYISO have led to the adoption of the 2002 load shapes to replace the 1995 shapes in their studies since they are more representative of the current system load shapes and tend to produce slightly more conservative results.

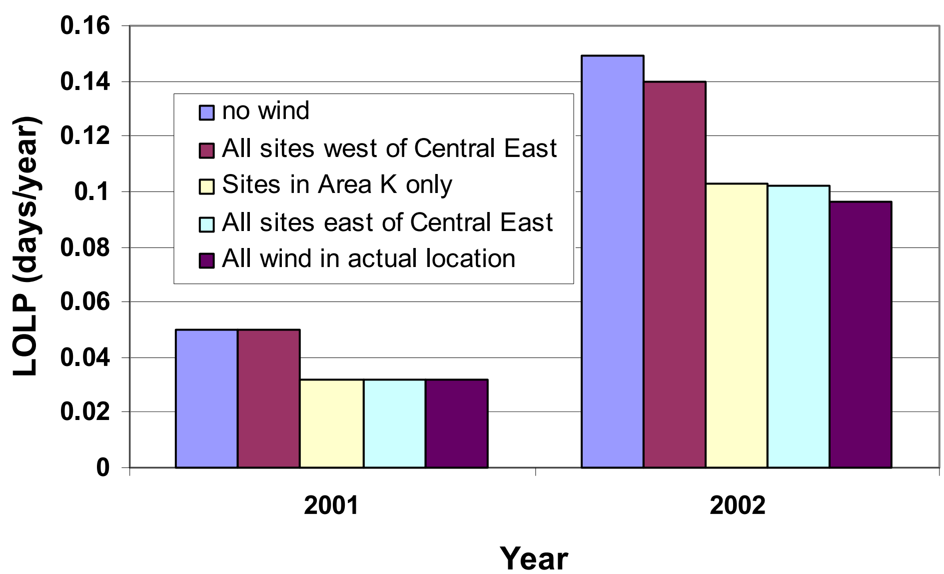

Figure 7.12 Annual Reliability Impact of Wind Sites

The columns on the far right of each group show the risk when all of the wind sites are added to the system. The intervening columns show the impact as various groups of the wind farms are added. In 2001 virtually all of the benefits, i.e., reduction in LOLP, come from the 600 MW site in Area K. The 2002 data shows some benefits from the other sites although the bulk of the impact still comes from the Area K site. (Note: In this report the terms “Area” and “Zone” are used interchangeably to describe the various geographic regions in the NYISO.)

7.3.2 UCAP calculations

While the fact that the risk is reduced from 0.05 to 0.032 days/year is interesting, the real question is how does that compare to the impact of adding a conventional generator to the system and how much of the value is due to the location of the wind farms versus the intermittent nature of their output.

Figure 7.13 represents the 2008 system risk for various scenarios based on the 2001 load and wind shapes. Of the three parallel lines, the top one represents the risk without the addition of any wind generation and the middle one represents the addition of the wind generation at their various sites across the state.

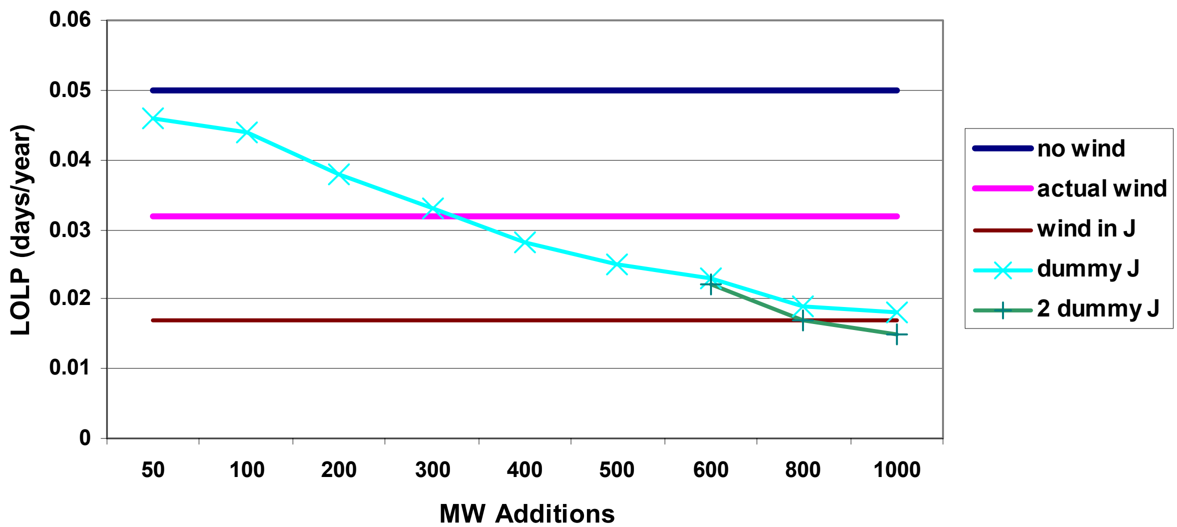

Figure 7.13 NYISO LOLP from 2001 Shapes

The bottom line represents the system risk impact if all of the wind generation shapes were assumed to occur in Area J, New York City. This indicates that 3,300 MW of wind generation with the 2001 hourly wind pattern would now further reduce the risk from 0.032 to 0.017 days/year if all of the wind generation were in New York City.

The curve slanting from upper left to lower right represents the addition of a conventional generator of various sizes with a 10% forced outage rate. Where the curves intersect represents the comparative value of the wind generation. In this case, the addition of the 3,300 MW of wind generation in their actual locations would have the same reliability benefit of adding a 300 MW generator in Area J, or about 270 MW (= 300 * .9) of UCAP. A saturation effect due to unit size occurs when the dummy unit exceeds 600 MW, so it was split into two dummy units. For the 2001 data, the 3,300 MW of wind generation, based on its output alone and not its location, would have the same impact on risk as 800 MW of conventional generation, or roughly 720 MW of UCAP.

Figure 7.14 shows the same analysis for the 2002 wind generation and load shapes. In this case the wind in its actual location is again comparable to about 300 MW of conventional generation in Area J, but its value independent of location is worth 500 MW, or about 450 MW of UCAP. Because the 2002 load data had risk contributions from a greater number of days, it provides a better measure of the value of the wind generation. The 2001 load data had fewer days contributing to the system risk and would therefore be much more affected by the performance, or lack thereof, of the wind on any given day. Also, as stated above, the NYISO has recently adopted the 2002 load shapes for future LOLP studies.

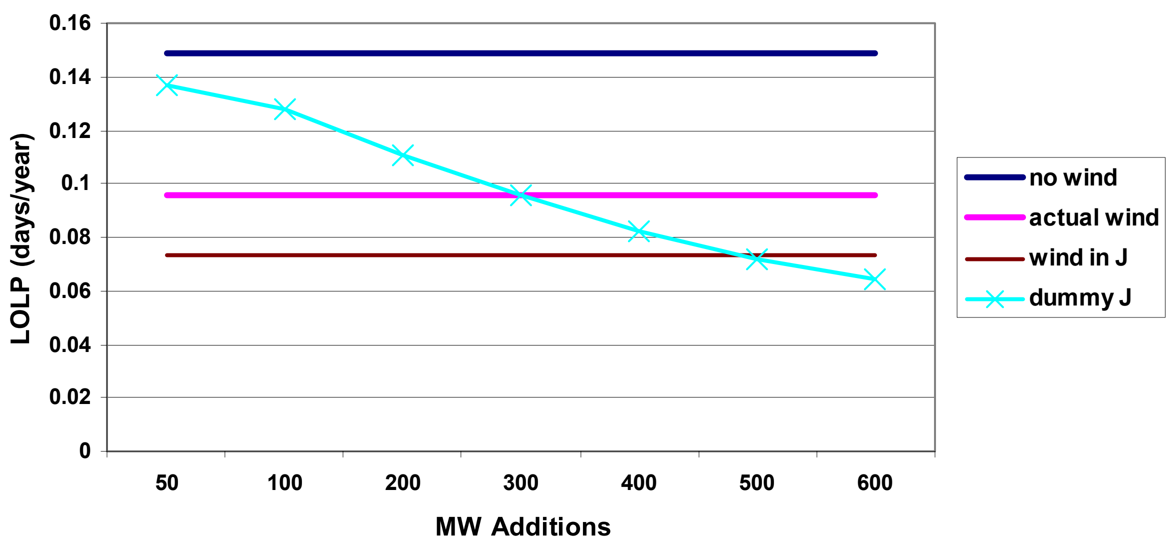

Figure 7.14 NYISO LOLP from 2002 Shapes

7.3.2.1 Comparison to Phase 1 Results

Figure 7.15 shows the results of the analysis in Phase 1 of this study. An additional curve, labeled “Dn EST,” has been added to correct the original “Downstate” curve due to shifting the original wind generation to Eastern Standard Time. The Phase 1 analysis showed that when the wind generation was sited in Area J it had a risk impact equal to a thermal generator rated about 7% of the wind rating. The adjusted results increased that to about 9%. The Phase 2 results show that the capacity value of wind generation is 15% of its rating, i.e., 500 MW conventional generation is equivalent to 3,300 MW of wind. This variation is examined further in (the next) Section 7.3.3, *Approximate Techniques*.

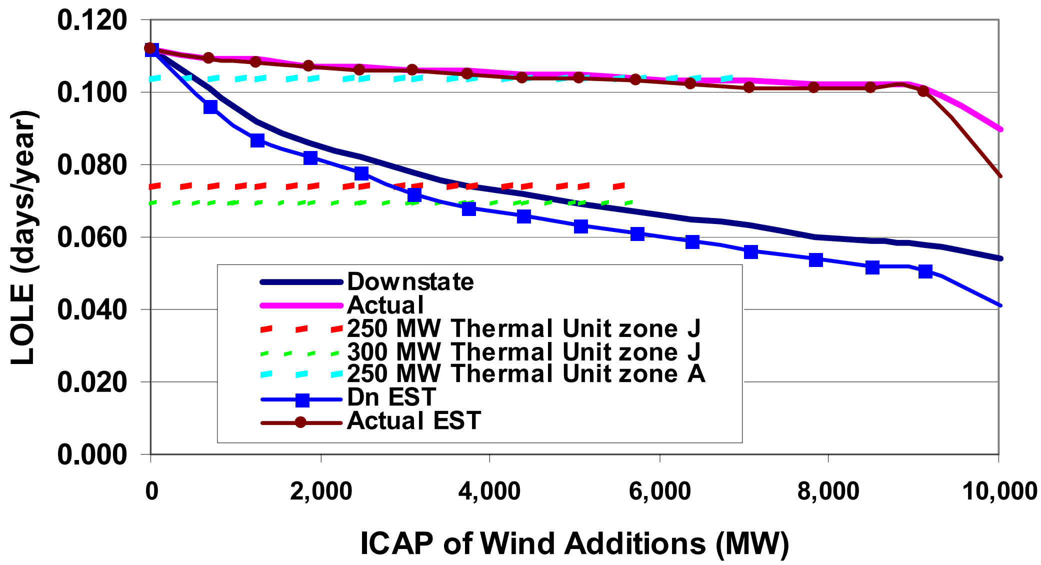

Figure 7.15 Phase 1 adjusted results

7.3.3 Approximate Techniques

While a detailed reliability analysis can show how much capacity value a wind generator is likely to produce, it would be helpful to have an easier, faster methodology to estimate the capacity value of wind generation. Figure 7.16 shows the NYISO daily peak load for 2003 with the summer months (June, July, August) highlighted in red. While the system risk is a function of many things, one of the key drivers is the load. The risk varies exponentially with peak load, so that essentially only loads above 90% of the peak provide significant contributions to the risk. Figure 7.16 illustrates why all of the risk generally occurs in the summer months.

The daily load shapes change slightly throughout the month. Figure 7.17 shows the hourly load shapes for June 2003. A few things stand out from these curves. First is that there are a few days above the rest of the pack in terms of their magnitude of loads. The second is that the peak load does not occur at the same hour every day. The NYISO reliability calculations only look at the peak load each day, not all of the hourly load values, so it is important to know when the peak occurs when evaluating the impact of wind generation. Figure 7.18 shows the hour of the day that the peak load occurred for the summer months in 2001 through 2003. Although other hours are present the bulk of the peak loads occur in the four hours of 14 through 17 inclusively. (Note, the period from midnight to 1:00 a.m. is hour 1.)

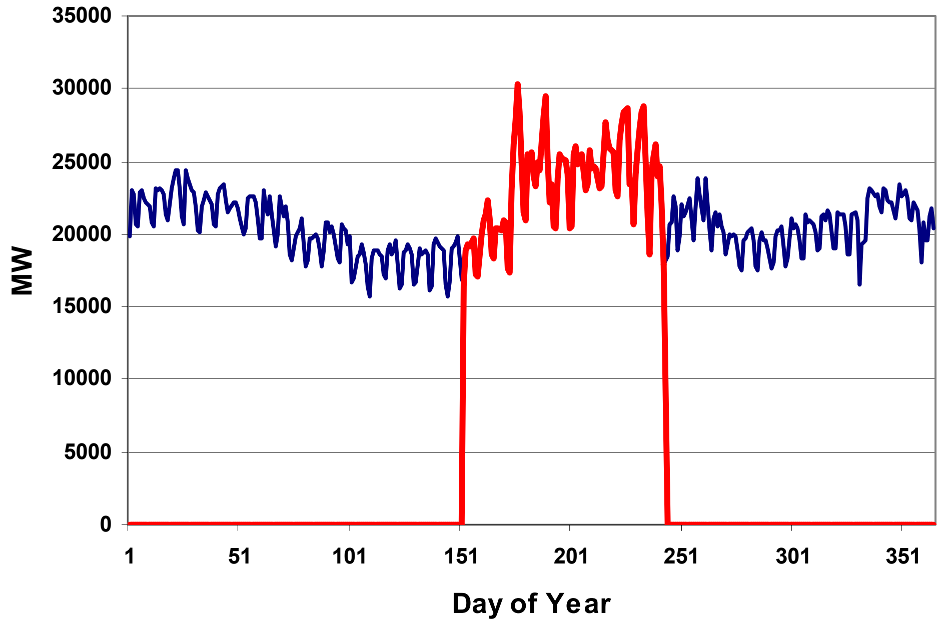

Figure 7.16 NYISO 2003 Daily Peak Load Profile

Figure 7.19 uses this four-hour definition to calculate a wind capacity factor for both all year and for the summer season. This is compared to the capacity factor for the entire year or for just those hours when the load is within either 5% or 10% of the peak load. Also shown, for the 2001 and 2002 shapes, is the effective capacity determined from the reliability analysis if either all of the wind is treated as being in area J or if the wind is represented in its actual location. While the value during only those hours that are within 5% to 10% of the peak are a good measure of the unit's effectiveness, it is difficult to estimate those hours in advance since both the wind and the loads are varying. The peak period in the summer is only a function of the wind and can be evaluated for various historical years for a site. This appears to give a very close approximation to the effectiveness based on just its intermittent nature ("wind in J"), particularly for the 2002 shapes.

This approximate technique can be used to investigate the difference between the Phase 1 results (~9%) and the Phase 2 analysis (~15%). Figure 7.20 shows the annual and peak capacity factors for all of the individual sites. Most of the sites range around 30% for the annual capacity factor and about 10% for the peak load period. The last site, in Area K, is an exception. Also shown for comparison are the site capacity factors during the hours within 5% and 10% of the peak load. In general these values tend to track each other within a few percent.

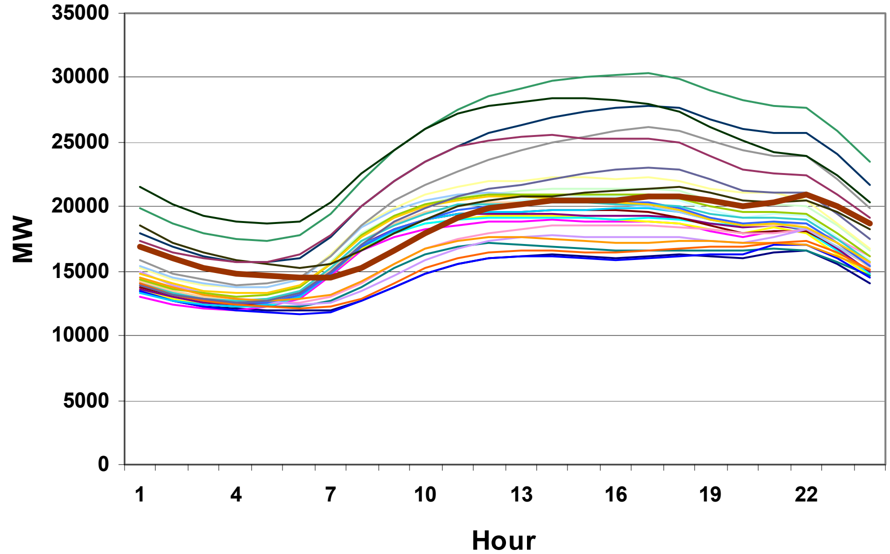

Figure 7.17 NYISO June 2003 Loads

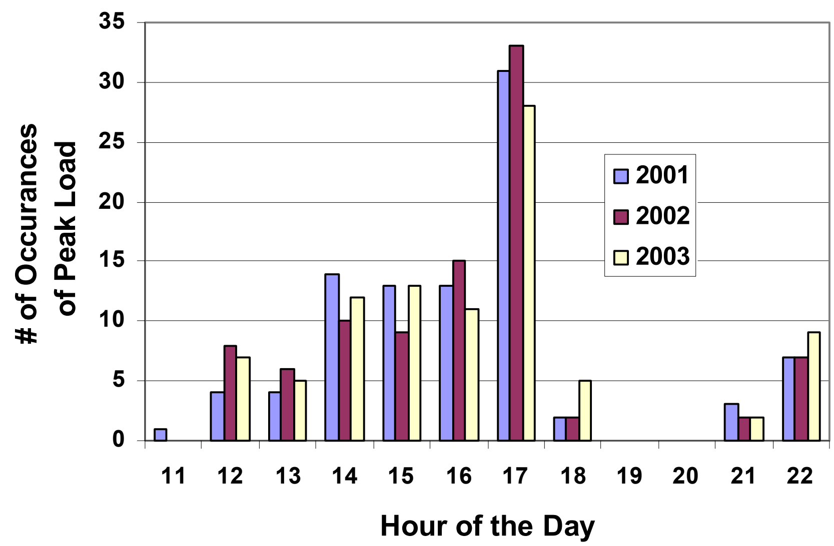

Figure 7.18 Peak Hour of the Day - Summer

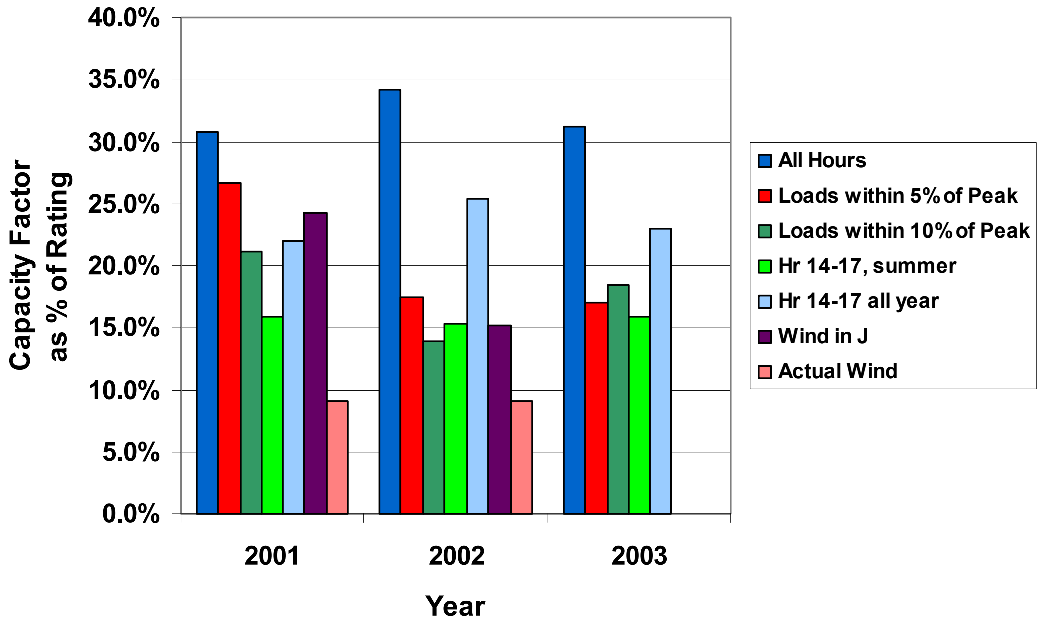

Figure 7.19 Wind Capacity Factors in Peak Load Hours

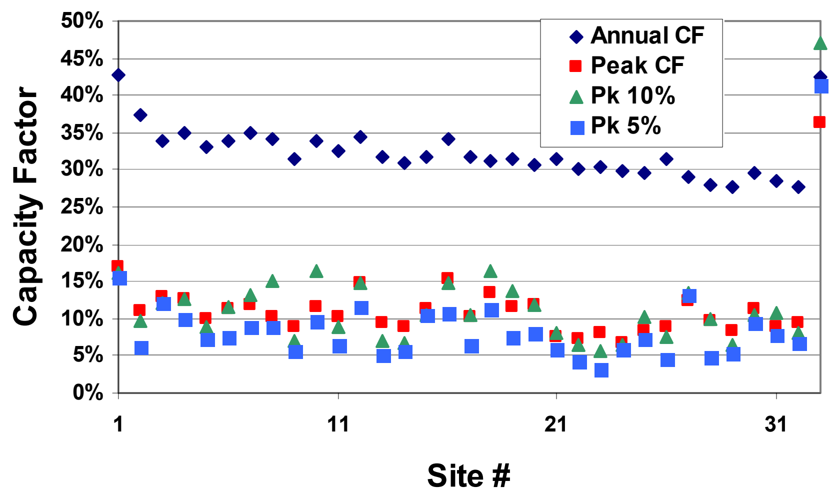

Figure 7.20 Annual and Peak Capacity Factors by Site for Year 2002 Shapes.

Figure 7.21 shows the key difference between the wind site in Zone K, which is an offshore location, and the rest of the wind sites in New York that are all inland. The offshore site has a much different daily pattern that peaks several hours earlier in the day and is much more in line with the load patterns.

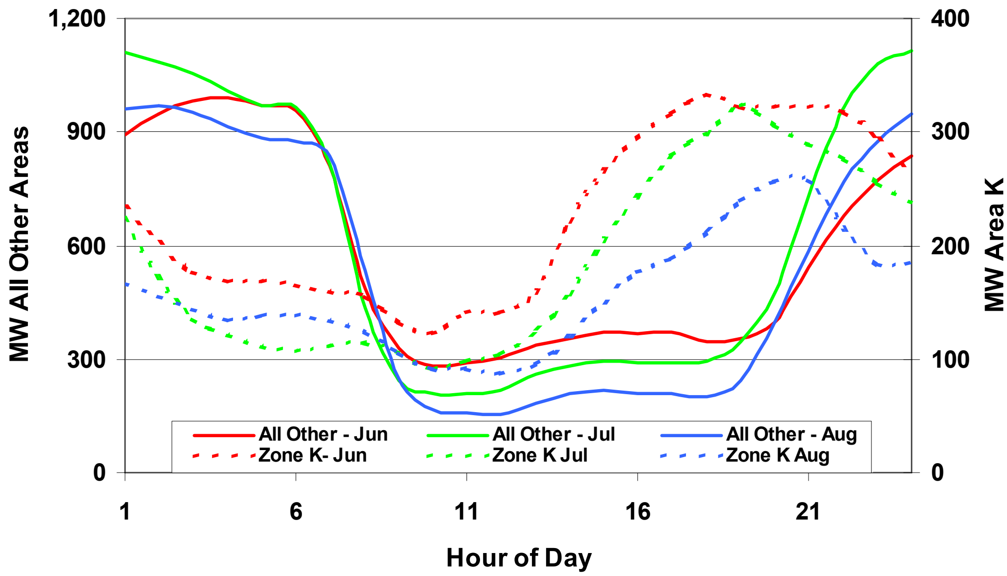

Figure 7.21 Average Hourly Wind Shapes for 2002

Figure 7.22 shows the annual and peak period capacity factors for the wind by zone and the NYISO average. Outside of Zone K the peak capacity factors ranged from 7% to 12%, which is much more in line with the results predicted in Phase 1. The Zone K values are above 35% in all years, and this is what brings the NYISO average values up to the 15% level. Figure 7.23 groups all of the inland sites together and shows that they average about a 10% capacity factor during the summer peak load period.

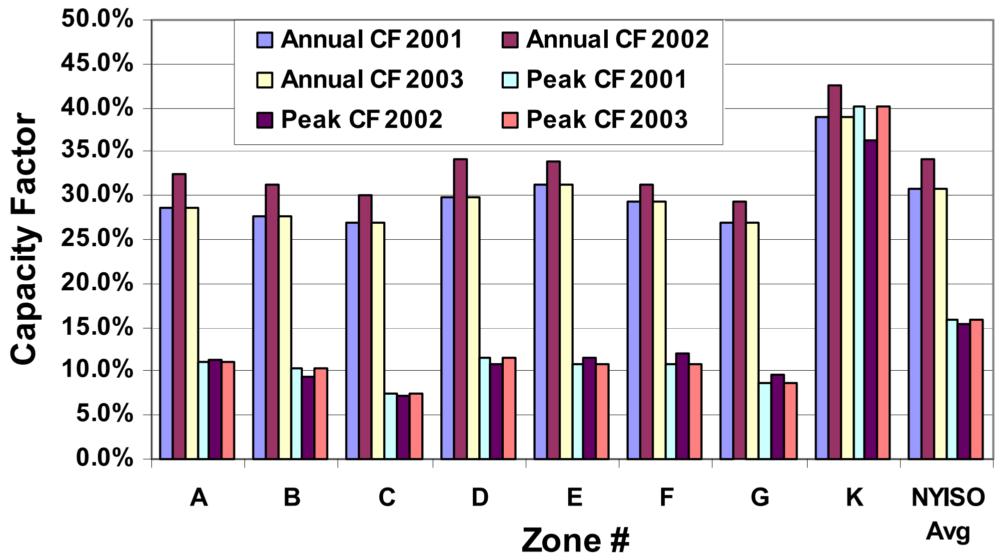

Figure 7.22 NYISO Wind Capacity Factors by Zone

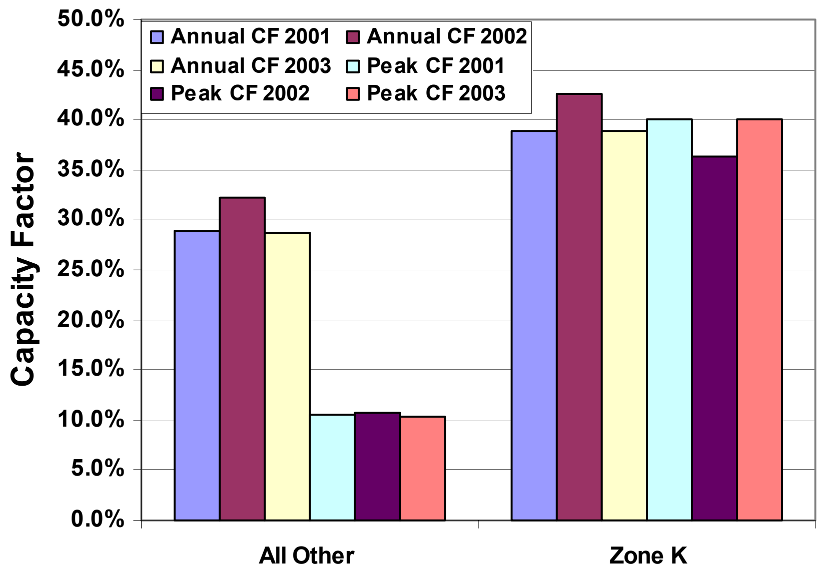

Figure 7.23 NYISO Wind Capacity Factors

7.4 Summary

Capacity factors of inland wind sites in New York are on the order of 30% of their rated capacity. Their effective capacities, however, are about 10%, due to both the seasonal and daily patterns of the wind generation being largely “out of phase” with the NYISO load patterns. The offshore site in Long Island exhibits both annual and peak period effective capacities on the order of 40%. The higher effective capacity is due to the daily wind patterns peaking several hours earlier in the day than the rest of the wind sites and therefore being much more in line with the load demand. As has been noted earlier, these capacity factors are based on the 2001 through 2003 meteorological data combined with the operating characteristics of the 1.5 MW GE wind turbine design. It is expected that future designs will show greater efficiencies with corresponding increases in effective capacities.

An approximate methodology was shown which bases the wind’s effective capacity on the capacity factor during a four-hour peak load period, 1 p.m. to 5 p.m., in the summer months. This produces results in close agreement with the full analytical methodology based on LOLP. This methodology could be used with a “predicted” history based on historical meteorological data and unit availabilities until such time that several years of actual operating history can be developed for a particular site. The actual operating history would automatically include the impact of unit planned and forced outages. Although the primary capacity market is in the summer, this methodology can be adapted for use in the winter capacity market as well.

8 Suggested Changes to Planning and Operating Practices

Previous sections of this report address the impact of wind generation on a diverse range of system operation and performance issues. Analytical results are described in detail, and the implications of those results are discussed.

One of this study's key objectives is to identify changes to existing planning and operation practices that should be considered due to the addition of wind generation in NY State. This section of the report draws from the analysis presented in other sections, and summarizes the impacts on existing planning and operating practices.

8.1 NYISO Planning Practices and Criteria

According to the NYISO's *System Reliability Impact Study Criteria and Procedures* document, the objectives of the SRIS are to:

1. Confirm that the proposed new or modified facilities associated with the project comply with applicable reliability standards.
2. Assess the impact of the proposed project on the reliability of the pre-existing power system.
3. Evaluate alternatives to eliminate adverse reliability impacts, if any, resulting from the proposed interconnection.
4. Assess the impact of the proposed project on transmission transfer limits, considering thermal, voltage and stability limitations, and estimate the increase or decrease in the Transfer Capability of affected transmission interfaces.

No changes to the SRIS criteria and procedures are recommended to accommodate wind generation projects. The key requirement in the SRIS criteria is that any new project must comply with applicable reliability standards, and that should not change.

New York State Reliability Council (NYSRC) reliability rules are outlined in the document *NYSRC Reliability Rules for Planning and Operating the New York State Power System*. The reliability rules define the reliability of the New York State Power System in terms of *adequacy* and *security*. There are a total of eleven reliability rules. Only those rules associated with transmission planning are discussed in this section.

The *Transmission Capability – Planning* rule establishes criteria for the planning of sufficient transmission resources to ensure the system ability to withstand design criteria contingencies without significant disruption to system operation. Both design criteria and extreme contingencies are evaluated in thermal, voltage and stability analyses. Recommendations concerning the application of the reliability rules to wind generation are discussed in the following subsections.

8.1.1 Impact of Wind Generation on Steady-State Analysis

Only selected issues relevant to the application of the NYSRC rules to steady-state analysis with wind generation are discussed in this section.

In accordance with the existing NYSRC rules, a steady-state analysis must evaluate design criteria contingencies (e.g., single element outages) as well as extreme contingencies (e.g., loss of all lines emanating from a substation). Single element (N-1) outages currently include the loss of a single generator, and it is recommended that an individual wind farm be considered a single generator for the purposes of this type of analysis. It is recommended that two types of wind farm design criteria outages be evaluated. The first outage is a conventional trip of the entire wind farm. The second outage actually represents the loss of wind, not the loss of the wind farm. This should be implemented as a reduction in wind farm power output from its initial value to zero, but with the wind farm still connected and therefore, still regulating voltage. The objective of this second type of test is to determine the change in voltage on buses in the local area and comparing the results to relevant criteria.

No changes to extreme contingencies, or multiple element outages, are recommended. The loss of wind across the entire state, for example, is not a credible outage. Loss of wind in local areas can be addressed under the existing rules. For example, the loss of all lines emanating from a substation is already included in the rules. Therefore, if two or more wind farms share a transmission substation interconnection, an assessment of the impact of the loss of these wind farms is a defined extreme contingency.

8.1.2 Impact of Wind Generation on Stability Analysis

Only selected issues relevant to the application of the NYSRC rules to stability analysis with wind generation are discussed in this section.

In accordance with the existing NYSRC rules, a stability analysis must also evaluate design criteria (e.g., a permanent three-phase fault on a generator with normal fault clearing) as well as extreme faults (e.g., permanent three-phase fault on a generator with delayed fault clearing). No changes in the interpretation of design criteria or extreme fault scenarios are recommended.

8.2 NERC, NPCC, and NYSRC Reliability Criteria

NERC, NPCC, and NYSRC policies and criteria were reviewed in Phase 1 of this project and documented in Chapter 6 of the Phase 1 report. The results of Phase 2 technical analysis reinforce the conclusions stated there.

The reliability standards themselves do not need to change to accommodate wind generation. The system should still be designed to meet a reliability criteria of 1 day in 10 years Loss of Load Probability, LOLP, and should still withstand the single largest contingency without causing cascading outages. However, the LOLP calculation methods should be modified to reflect the intermittent nature of the wind, as described briefly in (the next) Section 8.3, *NYISO Transmission Reliability and Capacity Requirements*, and more fully in Section 7, *Effective Capacity*.

One concern that was raised was "Would the introduction of 3,300 MW of wind generation create a new *most severe* single contingency?" Analysis of historical statewide wind data indicates that loss of wind generation due to abrupt loss of wind in not a credible contingency. Short-term changes in wind are stochastic (as are short-term changes in load).

A review of the wind plant data revealed no sudden change in wind output in three years that would be sufficiently rapid to qualify as a loss-of-generation contingency for the purpose of stability analysis. While the wind can vary rapidly at a given location, turbines are spread out in a project, and the projects are spread throughout the state, making such an abrupt drop in the total output an extremely unlikely event. It was concluded that each wind project can be treated as separate generating unit for contingency analysis.

Figure 8.1 below shows a histogram of the hourly deltas in wind generation from the assumed 3,300 MW of wind farms in New York. In general, the changes are well within ±600 MW and the extreme values are less that the ±1200 MW criteria. And these represent the changes from one hour to the next. Instantaneous changes, or changes within a few minutes, would be significantly smaller. There are hours with low wind output, as shown in Figure 8.2, but they are generally preceded by other hours that are also relatively low.

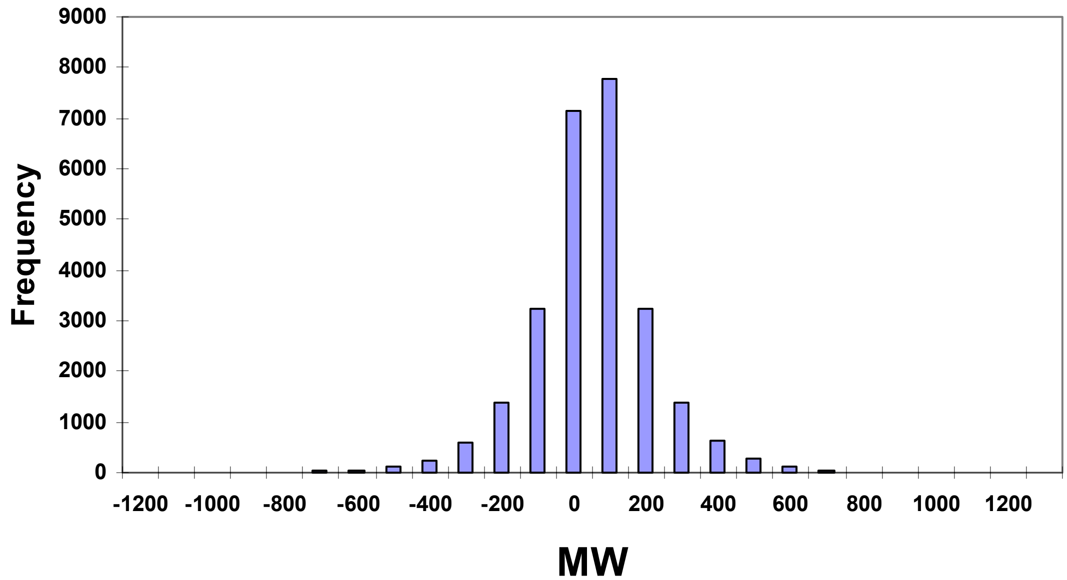

Figure 8.1. Hourly Wind Deltas, 2001 through 2003

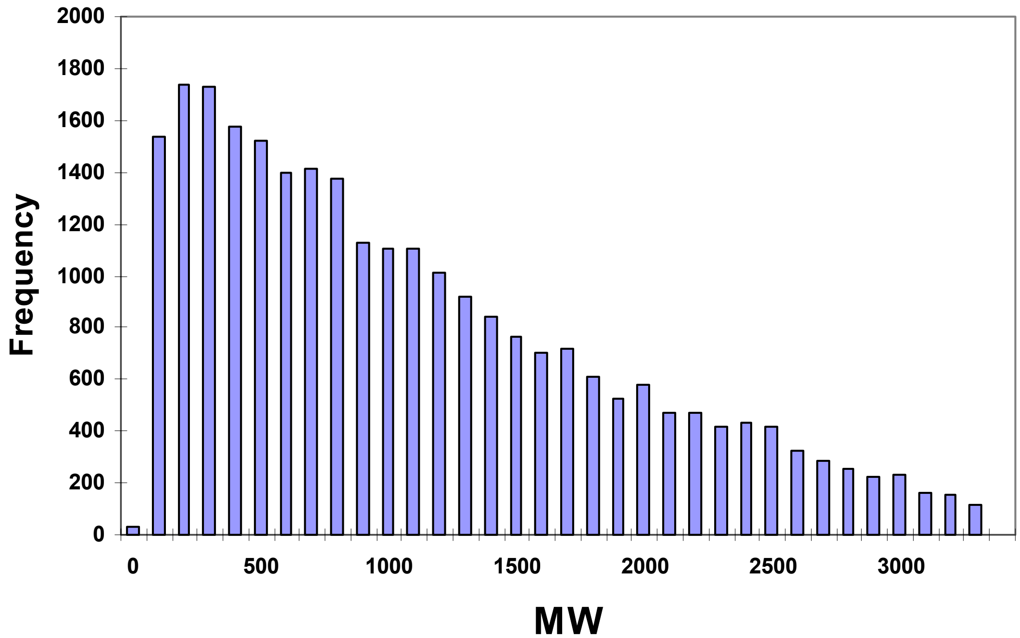

Figure 8.2. Hourly Wind Outputs, 2001 through 2003

8.3 NYISO Transmission Reliability and Capacity Requirements

The existing reliability assessment in New York is based on the Installed Capacity, ICAP, analysis performed each year which uses a Monte Carlo based program (MARS) to determine the amount of installed capacity required to meet a "one day in ten years" Loss of Load Probability, LOLP, based on the daily peak loads and recognizing transmission constraints and support from neighboring systems. This ICAP requirement, currently set at 18% reserves for the 2005 summer peak, is then converted to a UCAP, or Unforced Capacity, requirement based on the forced outages of the generators. The UCAP of a 100 MW generator with a 10% forced outage rate is 90 MW [= 100 * (1.0 –0.1)]. The current UCAP requirement is roughly 12% reserves. The UCAP is what is used in the bidding in the capacity market.

Because wind generation is an intermittent source that cannot be controlled, it needs to be evaluated in a manner different from conventional generation. But while its output can't be controlled (except downward) it can be predicted. Based on the analysis performed in this study, a 100 MW wind farm in upstate New York with a 30% annual capacity factor will have a UCAP of roughly 10 MW. A 100 MW offshore wind farm in Long Island may have a 40% capacity factor and a UCAP of 40 MW. The differences in their effectiveness are due the differences in their expected daily and seasonal patterns. This study recommends that the UCAP of wind generation be determined from the unit's expected capacity factor during the summer peak load period. This analysis determined that the four-hour period from hour ending 14 through 17 inclusive (1:00 to 5:00 pm) for the months of June, July and August, produced effective capacities in line with their overall reliability impact in the full LOLP calculations.

At present there is a locational requirement for New York City and Long Island which requires that a specified percentage of their UCAP requirements must be met locally. Other than that, there are no locational factors in the calculation of UCAP. A hypothetical 100 MW conventional generator with a 10% forced outage rate is worth 90 MW of UCAP whether it is in Buffalo or New York City. Therefore, there should be no locational consideration in the calculation of a UCAP for wind generation.

If a system ICAP needs to be determined, then it is suggested that the ICAP of the wind generation should be set equal to its UCAP in order to avoid any radical changes in the system ICAP values. If this is not done, then replacing 300 MW of conventional generation with 3,000 MW of wind generation (with a UCAP of 300 MW) would make the ICAP appear to rise from 18% to over 26%, resulting in a misleading measure of the system's installed capacity reserves.

8.4 Ancillary Services

Ancillary services in New York State include capacity (UCAP), regulation, and spinning reserves. The addition of wind generation to the NYISO should have minimal impact on the ancillary services market.

Capacity: The methodology for calculating the UCAP of wind must be different from the methodology for conventional generation, due to the variable nature of the power source (see Chapter 7). However, wind generation participation in the UCAP market should be exactly the same as for other units.

Regulation: A 36 MW (3σ) increase in regulating capability should maintain the existing level of regulation performance with the addition of 3,300 MW of wind generation. However, the NYSBPS presently exceeds NERC regulation performance criteria for CPS1 and CPS2. It is possible that the NYSBPS could meet minimum NERC requirements with no increase in regulating capability.

Spinning Reserve: Even with the addition of 3,300 MW of wind generation, no change in the spinning reserve criteria is required. Based on the geographic diversity of the wind across the system, the simultaneous loss of wind throughout the system is not a credible contingency. And while there may be periods of zero wind in the state they are likely to be preceded by periods of very little wind, so that there is no need to change the existing 1,200 MW value as the largest system contingency, as discussed above.

8.5 NYISO Market Design

Current estimates on the day-ahead forecast accuracy for wind are fairly high when viewed across a projected 3,300 MW of wind capacity spread across the state. The accuracy for individual wind farms will not be as high and it may be appropriate for multiple wind farms to merge their forecasts on a zonal or regional basis. The existing day-ahead and hour-ahead energy markets in New York have sufficient flexibility to accommodate wind generation without any significant changes. It may also be advantageous for the forecasting to be performed from a central location to ensure a consistency of methodologies and so that changing weather patterns can be noted quickly. With these factors in place wind generation can be held accountable to similar standards as conventional generation in terms of meeting their day-ahead forecast, with one exception; imbalance penalties should not be imposed on wind generation Wind projects would need to settle discrepancies between their forecast and actual outputs in the energy balancing market.

However, because wind is largely non-dispatchable, any additional penalties for imbalance should be eliminated. The FERC Order 888 allows imbalance *penalties* to be applied to generators that operate outside of their schedule. As applied in New York, any "overgeneration" can be accepted without payment and any "undergeneration" is priced at the *greater* of 150% of the spot price or $100/MWh. Strict application of these policies in the MAPS analysis performed would result in the loss of roughly 90% of the wind generation revenue, which would be disastrous to their future development. The intent of the penalties is to prevent generators from "gaming" the market but their application to intermittent resources such as wind and solar would result in negative and unintended consequences. If a wind generator forecasted 100 MW for a particular hour but can only produce 80 MW due to a lack of wind then no amount of penalties can get them to produce the remaining 20 MW. Their only option would be to bid less, or zero, in the day ahead market and possibly even bid low in the hour ahead market. However, the MAPS analysis showed that as much as 25% of the value of the wind energy to the system could be lost if it is not properly accounted in the day ahead commitment process. Any imbalance penalties for under-generation would tend to encourage underbidding the day ahead forecast, to the detriment of the entire system.

Care should be taken in the structuring of any financial incentives that may be offered to encourage the development of wind generation. The market for wind generation (including incentives) should be structured to:

- reward the accuracy of wind generation forecasts, and
- encourage wind generators to curtail production during periods of light load and excessive generation.

The second item above is particularly critical to overall system reliability. If excessive wind generation causes the NYISO to shut down critical base-load generators with long shutdown/restart cycle times, the system could be placed in a position of reduced reliability. The market for wind power should be structured so that wind generators have clear financial incentives to reduce output when energy spot prices are low (or negative). In addition, the NYISO must have the capability to limit or curtail power from wind generators when necessary for system reliability reasons. Such curtailment could be done via wind farm operators (similar to the existing process for re-dispatching a thermal generator via the plant operator) or via SCADA for the case of unmanned generation facilities.

One change that should be incorporated immediately is the accurate recording of forecasts and actual production for all existing and new facilities on at least an hourly and five-minute basis. Shorter time frames, i.e., six seconds, should also be recorded during volatile periods. The existence of this data will greatly facilitate the planning and operations of the system when several thousand megawatts of wind are present.

9 References

[i] Wan, Y.; D. Bucaneg; "Short-Term Fluctuations of Large Wind Power Plants," NREL CP 500-30745, 2002.
[ii] NERC Planning Standards, pg 20, September 1997.
[iii] FERC NOPR, "Interconnection for Wind Energy and Other Alternative Technologies," Docket No. RM05-4-000, January 24, 2005.
[iv] "Overview of Wind Energy Generation Forecasting," AWS TrueWind, report to NYSERDA and NYISO, January 25, 2005
[v] ibid. pg7-8.
[vi] NYISO Manual "Day Ahead Scheduling", June 12, 2001.
[vii] "NYSRC Reliability Rules for Planning and Operating the New York State Power System," New York State Reliability Council, L.L.C., Version 9, January 9, 2004
[viii] "Overview of Wind Energy Generation Forecasting," AWS TrueWind, report to NYSERDA and NYISO, January 25, 2005
[ix] "The Effects of Integrating Wind Power on Transmission Planning, Reliability, and Operations; Report on Phase 1: Preliminary Overall Reliability Assessment." NYSERDA Report, February 2, 2004
[x] NERC Policy 1, "Generation Control and Performance," (Reference on CPS1 and CPS2)
[xi] "NYCA Variable Regulation Requirements Analysis and Action Plan," NYISO, February 27, 2003
[xii] Wan, Y.; D. Bucaneg; "Short-Term Fluctuations of Large Wind Power Plants," NREL CP 500-30745, 2002.
[xiii] NREL Data records from an existing wind project in northwestern Iowa
[xiv] Zavadil, R.M.; "Wind Generation Technical Characteristics for the NYSERDA Wind Impact Study," January 5, 2004.
[xv] ibid.
[xvi] FERC NOPR, "Interconnection for Wind Energy and Other Alternative Technologies," Docket No. RM05-4-000, January 24, 2005.

Appendices