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Utility Wind Integration State of the Art

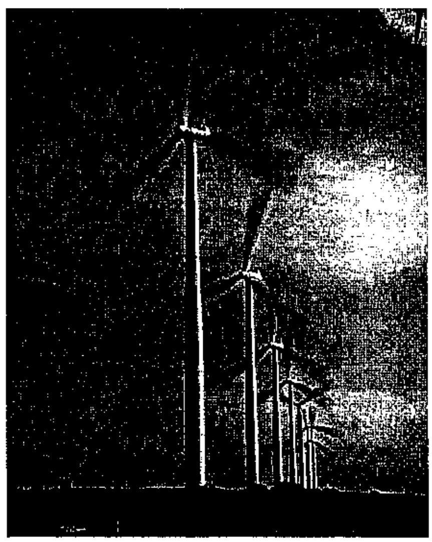

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Exhibit 4 -- B

Overview and Summary

In just five years from 2000-2005, wind energy has become a significant resource on many electric utility systems, with over 50,000 MW of nameplate capacity installed worldwide at the end of 2005. Wind energy is now "utility scale" and can affect utility system planning and operations for both generation and transmission. The utility industry in general, and transmission system operators in particular, are beginning to take note. At the end of 2005, the Power Engineering Society (PES) of the Institute of Electrical and Electronic Engineers (IEEE) published a special issue of its ***Power & Energy Magazine*** (Volume 3, Number 6, November/December 2005) focused on integrating wind into the power system. This document provides a brief summary of many of the salient points from that special issue about the current state of knowledge regarding utility wind integration issues. It does not support or recommend any particular course of action or advocate any particular policy or position on the part of the coöperating organizations.

The discussion below focuses on wind's impacts on the operating costs of the non-wind portion of the power system and on wind's impacts on the electrical integrity of the system. These impacts should be viewed in the context of wind's *total* impact on reliable system operation and electricity costs to consumers. The case studies summarized in the magazine address early concerns about the impact of wind power's variability and uncertainty on power system reliability and costs. Wind resources have impacts that can be managed through proper plant interconnection, integration, transmission planning, and system and market operations.

On the cost side, at wind penetrations of up to 20% of system peak demand, system operating cost increases arising from wind variability and uncertainty amounted to about 10% or less of the wholesale value of the wind energy.[1] These incremental costs, which can be assigned to wind-power generators, are substantially less than imbalance penalties generally imposed through Open Access Transmission Tariffs under FERC Order No. 888. A variety of means – such as commercially available wind forecasting and others discussed below – can be employed to reduce these costs. In many cases, customer payments for electricity can be decreased when wind is added to the system, because the operating-cost increases could be offset by savings from displacing fossil fuel generation.

Further, there is evidence that with new equipment designs and proper plant engineering, system stability in response to a major plant or line outage can actually be improved by the addition of wind generation. Since wind is primarily an energy – not a capacity – source, no additional generation needs to be added to provide back-up capability provided that wind capacity is properly discounted in the determination of generation

[1] These conclusions will need to be reexamined as results of higher-wind-penetration studies -- in the range of 25% to 30% of peak balancing-area load -- become available. However, achieving such penetrations is likely to require one or two decades. During that time, other significant changes are likely to occur in both the makeup and the operating strategies of the nation's power systems. Depending on the evolution of public policies, technological capabilities, and utility strategic plans, these changes can be either more or less accommodating to the natural characteristics of wind power plants.

capacity adequacy. However, wind generation penetration may affect the mix and dispatch of other generation on the system over time, since non-wind generation is needed to maintain system reliability when winds are low.

Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution is likely to be up to 40% of a typical project's nameplate rating, depending on local wind characteristics and coincidence with the system load profile. Wind generation may require system operators to carry additional operating reserves. Given the existing uncertainties in load forecasts, the studies indicate that the requirement for additional reserves will likely be modest for broadly distributed wind plants. The actual impact of adding wind generation in different balancing areas can vary depending on local factors. For instance, dealing with large wind output variations and steep ramps over a short period of time could be challenging for smaller balancing areas, depending on the specific situation.

The remainder of this document is divided into four sections: wind plant interconnection, wind plant integration, transmission planning and market operation, and accommodating more wind in the future.

Wind Plant Interconnection

- Wind power plant terminal behavior is different from that of conventional power plants, but can be compatible with existing power systems. With current technology, wind-power plants can be designed to meet industry expectations such as riding through a three-phase fault, supplying reactive power to the system, controlling terminal voltage, and participating in SCADA system operation.
- Increased demands will be placed on wind plant performance in the future. Recent requirements include low voltage ride-through capability, reactive power control, voltage control, output control, and ramp rate control. Future requirements are likely to include post-fault machine response characteristics more similar to those of conventional generators (e.g., inertial response and governor response).
- Better dynamic models of wind turbines and aggregate models of wind plants are needed to perform more accurate studies of transmission planning and system operation.
- In areas with limited penetration, modern wind plants can be added without degrading system performance. System stability studies have shown that modern wind plants equipped with power electronic controls and dynamic voltage support capability can improve system performance by damping power swings and supporting post-fault voltage recovery.
- Because of spatial variations of wind from turbine to turbine in a wind plant – and to a greater degree from plant to plant – a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event.

Wind Plant Integration

- Utility planners traditionally view new generation primarily in terms of its *capacity* to serve peak demand. But wind is primarily an *energy* resource. Its primary value lies in its ability to displace energy produced from the combustion of fossil fuels and to serve as a hedge against fuel price risk and future restrictions on emissions.

- The addition of a wind plant to a power system does not require the addition of any backup conventional generation since wind is used primarily as an energy resource. In this case, when the wind is not blowing, the system must rely on existing dispatchable generation to meet the system demand.
- Wind plants provide additional planning reserves to a system, but only to the extent of their capacity value. Capacity for day-to-day reliability purposes must be provided through existing market mechanisms and utility unit commitment processes.
- The capacity value of wind generation is typically up to 40% of nameplate rating, and depends heavily on the correlation between the system load profile and the wind plant output.
- The addition of a wind plant to a power system increases the amount of variability and uncertainty of the net load. This may introduce measurable changes in the amount of operating reserves required for regulation, ramping and load-following. Operating reserves may consist of both spinning and non-spinning reserves. In two major recent studies, the addition of 1,500 MW and 3,300 MW of wind (15% and 10%, respectively, of system peak load) increased regulation requirements by 8 MW and 36 MW, respectively, to maintain the same level of NERC control performance standards.
- Fluctuations in the net load (load minus wind) caused by greater variability and uncertainty introduced by wind plants have been shown to increase system operating costs by up to about $5/MWH at wind penetration levels up to 20%. The greatest part of this cost is associated with the uncertainty introduced into day-ahead unit commitment due to the uncertainty in day-ahead forecasts of real-time wind energy production.
- The impact of adding wind generation can vary depending on the nature of the dispatchable generating resources available, market and regulatory environment, and characteristics of the wind generation resources as compared to the load. Dealing with large output variations and steep ramps over a short period of time (e.g., within the hour) could be challenging for smaller balancing areas, depending on their specific situation.
- Wind's variability cannot be treated in isolation from the load variability inherent in the system. Because wind and load variability are statistically uncorrelated, the net increase of variability due to the addition of wind is less than the variability of the wind generation alone.
- Commercially available wind forecasting capability can reduce the costs associated with day-ahead uncertainty substantially. In one major study, state-of-the-art forecasting was shown to provide 80% of the benefits that would result from perfect forecasting.
- Implementation of wind-plant-output forecasting in both power market operation and system operations planning in the control room environment is a critical next step in accommodating increasing amounts of wind penetration in power systems.

Transmission Planning and Market Operation

- Upgrades or additions to transmission facilities may be needed to access locations with large wind-energy potential. Current transmission planning processes are able to identify solutions to transmission problems, but the time required for implementation of solutions often exceeds wind-plant permitting and construction times by several years.
- Well-functioning hour-ahead and day-ahead markets provide the best means of addressing the variability in wind plant output.
- Energy imbalance charges based on actual costs or market prices provide appropriate incentives for accurate wind forecasting. Since wind plant operators have no control over the wind, penalty charges applied to wind imbalances do not improve system reliability. Market products and tariff instruments should properly allocate actual costs of generation energy imbalance.
- Wind turbine output or ramp rates may need to be curtailed for limited periods of time to meet system reliability requirements economically.
- Consolidation of balancing areas or the use of dynamic scheduling can improve system reliability and reduce the cost of integrating additional wind generation into electric system operation.

Accommodating More Wind in the Future

- Understanding and quantifying the impacts of wind plants on utility systems is a critical first step in identifying and solving problems.
- A number of steps can be taken to improve the ability to integrate increasing amounts of wind capacity on power systems. These include:
    - Improvements in wind-turbine and wind-plant models
    - Improvements in wind-plant operating characteristics
    - Carefully evaluating wind-integration operating impacts
    - Incorporating wind-plant forecasting into utility control-room operations
    - Making better use of physically (in contrast with contractually) available transmission capacity
    - Upgrading and expanding transmission systems
    - Developing well-functioning hour-ahead and day-ahead markets, and expanding access to those markets
    - Adopting market rules and tariff provisions that are more appropriate to weather-driven resources
    - Consolidating balancing areas into larger entities or accessing a larger resource base through the use of dynamic scheduling.

The ***Power & Energy Magazine*** articles summarized in this document are available to IEEE PES members at the following link:
http://www.ieee.org/portal/site/pes/menuitem.bfd2bcf5a5608058fb2275875bac26c8/index.jsp?&pName=pes_home

and to UWIG members at www.uwig.org through the Members link.

Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*

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Introduction and Background

During 2005 approximately 2,500 MW of wind capacity was added in the United States, which brought installed wind capacity to about 9,150 MW. Although the total wind capacity in the United States is less than in some countries, wind energy has caught the attention of some utilities that depend on natural gas to generate power. There is evidence that wind development will continue at significant levels in the United States for the next several years, although it may be sensitive to a number of factors that include transmission availability, wind turbine availability, prices of wind technology and competing fuels, production tax credit availability, and states' renewable portfolio standards (RPSs).

This trend has helped induce electricity providers to investigate the potential impact of wind on the power system. Because of wind power's unique characteristics, many concerns are based on the increased variability that wind contributes to the grid, and most U.S. studies have focused on this aspect of wind generation. Grid operators are also concerned about the ability to predict wind generation over several time scales.

In this report we discuss some recent studies that have occurred in the United States since our previous work [2, 3]. The key objectives of these studies were to quantify the physical impacts and costs of wind generation on grid operations and the associated costs. Examples of these costs are (a) committing unneeded generation, (b) allocating more load-following capability to account for wind variability, and (c) allocating more regulation capacity. These are referred to as "ancillary service" costs, and are based on the physical system and operating characteristics and procedures. This topic is covered in more detail by Zavadil et al. [4].

Time Frames of Wind's Impact

Wind can have an impact on several time scales that correspond to grid operations. The shortest is generally in the range of milliseconds to seconds, and is the domain of system dynamic stability studies. Most wind integration studies

* Portions of this paper have been adapted from IEEE Power & Energy, November/December 2005 [1].

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focus on longer time scales, but the stability time frame is a concern and recent developments in the United States have addressed this issue. The most important is the Federal Energy Regulatory Commission (FERC) limited grid code for wind plants, contained in FERC Order 661A, issued in December 2005 [5]. This ruling addresses the issues of low-voltage ride-through, reactive power supply, and Supervisory Control and Data Acquisition (SCADA) system requirements

Figure 1 illustrates the key time frames that correspond to utility/grid operations and that have been the focus of most integration studies. In the United States, the regulation time frame is the period during which generation automatically responds to deviations in load or load net wind. This capability is typically provided via automatic generation control, and is a capacity service generally covering seconds to several minutes. Integrating wind into the system would have an impact on regulation requirements for the system, and might require additional regulation capability. In the United States there are two controlled performance standards, CPS-1 and CPS-2*, control area operators/balancing authorities follow.

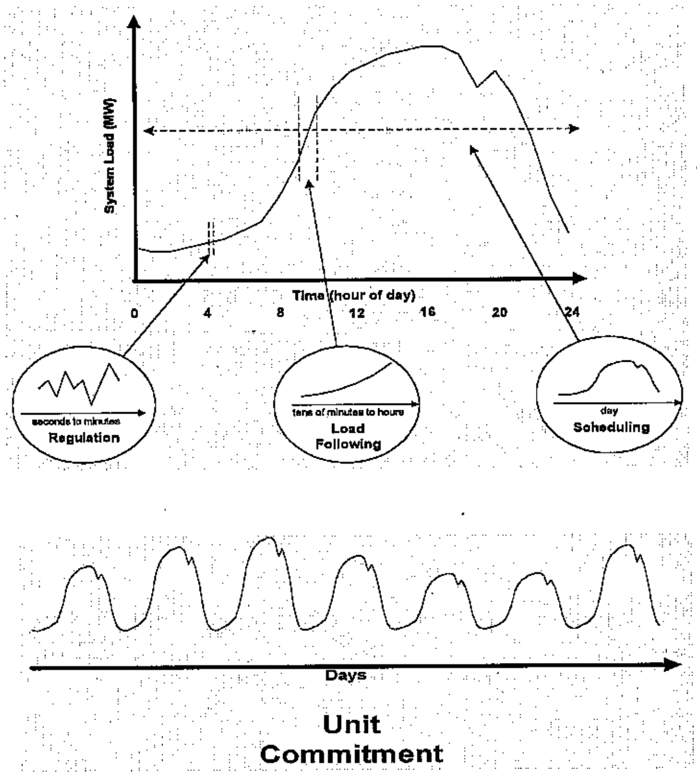

Figure 1. Time frames for wind impacts

The second time frame is load following. This is a longer period during which generating units are moved to different set points of capacity, subject to various operational and cost constraints. Load following involves capacity and energy, and corresponds to time scales that may range from 10 minutes to a few hours. Loads can typically be forecast with reasonable accuracy and overall correlation between individual loads tends to be high in this time frame. Generating units that have been previously committed, or can be started quickly, can provide this service, subject to physical constraints. Beyond the maximum and minimum generation constraints, the ramping constraint (ability to move in MW/minute) may be affected by significant wind generation on the system. In systems with little or no wind, the changes in load in this time frame can be predicted with varying degrees of accuracy. To the extent that forecasts are wrong, the system operator must deal with the resulting system imbalance. Significant wind capacity can increase the uncertainty and cost in this time frame.

* These control performance standard cover short-term frequency variations (CPS-1) and longer term imbalance limits (CPS-2) on a statistical basis.

Planning for the required quantity of generation and load following capability involves the unit commitment time frame, which can range from several hours to a few days. Scheduling too much generation can increase costs needlessly, whereas insufficient generation could have a cost component (buying at high market prices or running expensive quick-start units) and a reliability component (if sufficient generation has not been started and is not available on short notice).

Most of the studies described here estimate the increased cost of managing a system with significant wind generation. The studies approach the cost question by starting with the physical behavior of the system without wind, then detailing how that physical behavior is affected by wind power plants. The primary objective of the studies is to take the view of the system operator, whose goal is to obtain system balance within required limits. Although U.S. terminology differs somewhat from that in Europe, the key physical issues and time frames are very similar. The imbalance impacts of wind are seen as unscheduled interchanges or frequency changes on the system when the balancing area cannot respond quickly enough to changes in load or wind. The impacts of wind on conventional generation are best analyzed over several time scales that correspond to system operation, ranging from automatic response (regulation in the United States) of units on automatic generation control, to spinning or standing reserve response (load-following in the United States). From the control room, wind variability is combined with load variability over these time scales, along with unscheduled deviations from some conventional generators. This net load is seen by the operator and must be balanced. Although the analytical tools differ somewhat, several common elements in the analyses have taken place in the United States.

Most of the studies we summarize here are cost-of-service studies that examine the cost of wind in the context of regulated utilities. Other studies, such as the one carried out in New York (discussed below) are market studies that do not directly calculate cost impacts. Because of this approach, the results of the market-based studies cannot be directly compared with ancillary cost studies. .

Xcel Energy North (Minnesota)

Xcel Energy North serves parts of North Dakota, South Dakota, Minnesota, Michigan, and Wisconsin. The power system is summer peaking with a peak demand of approximately 8,000 MW in 2002 projected to rise to approximately 10,000 MW by 2010. Total system generation is approximately 7,500 MW with the difference made up by power purchases.

Minnesota Department of Commerce Study (September 2004)

In 2004, a follow-up to an earlier study of the Xcel North system was completed by EnerNex Corporation on behalf of Xcel Energy and the Minnesota Department of Commerce. This study also focused on operating impacts but at the higher level of 1,500 MW of wind generation (15% penetration in 2010). It determined the incremental costs that resulted from plans and procedures needed to accommodate wind generation and maintain the reliability and security of the power system.

Meteorological simulations were carried out by WindLogics, then combined with archived weather data to recreate the weather for use in the study analysis. Benefits of geographic dispersion of the wind plants and of wind forecasting were also demonstrated. Figure 2 illustrates the area of meteorological modeling that was used to simulate 3 years of 10-minute wind speed data, subsequently converted to wind power output for the system simulations.

The costs of integrating 1,500 MW of wind generation into the Xcel North control area in 2010 are no higher than $4.60/MWh of wind generation and are dominated by costs incurred by Xcel Energy in the day-ahead time frame to accommodate the variability of wind generation and associated wind-generation forecast errors. The total costs include about $0.23/MWh resulting from an 8-MW increase in regulation requirements and $4.37/MWh resulting from scheduling and unit commitment costs. The study characterized these results as conservative, since improved strategies for short-term planning and scheduling and the full impact of new regional markets were not considered. Load following impacts were calculated, but because they were quite small, the cost was judged to be insignificant. Figure 3 shows the impact of wind on morning load pickup and evening ramp-down.

This study also calculated wind capacity credit as a percentage of installed wind. Several modeling approaches and different wind configurations were used to determine the capacity values, which were 26%–34%.

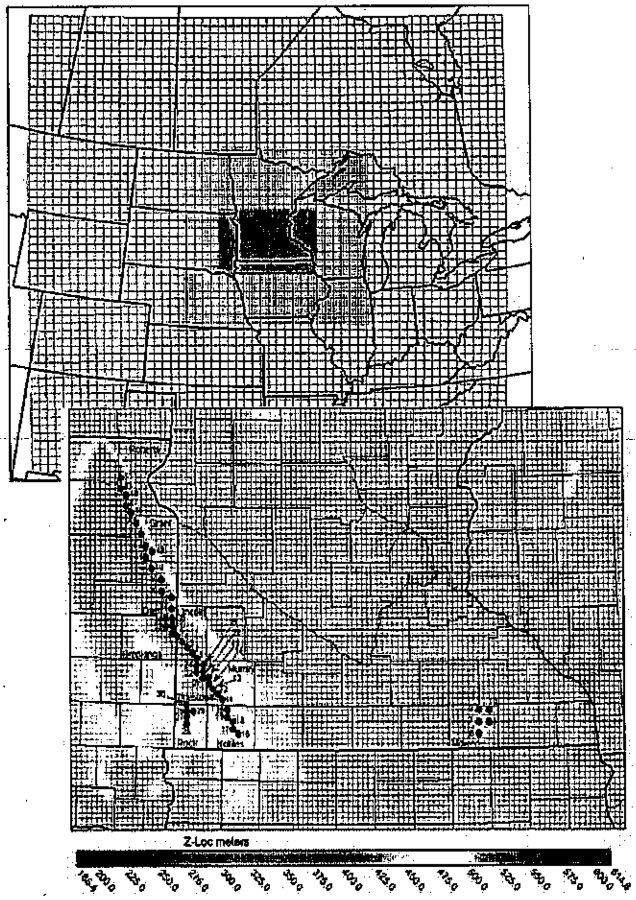

Figure 2. Area of meteorological modeling for Xcel Energy North study

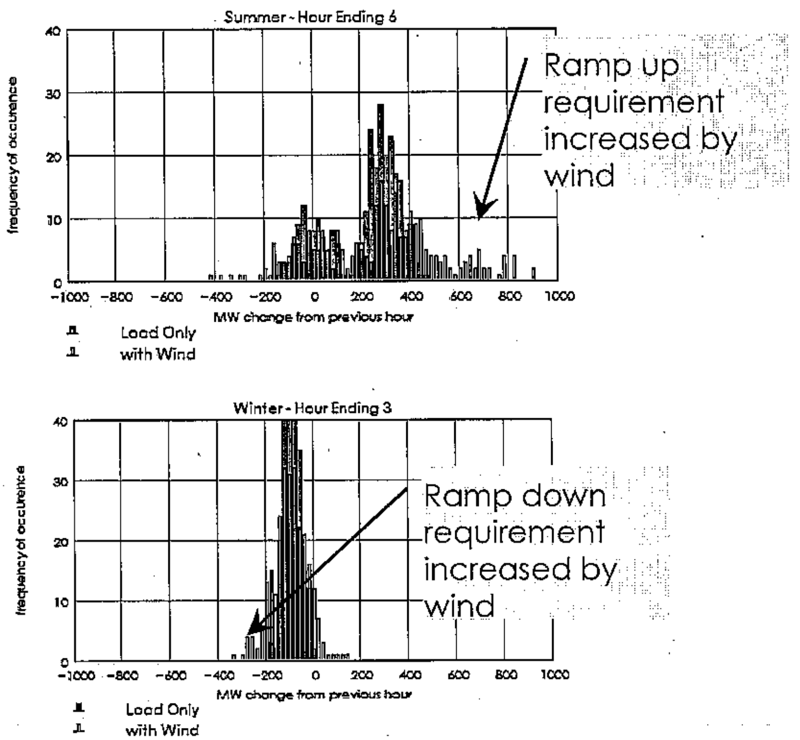

Figure 3. Load following impact on morning/evening ramps for Xcel Energy North

California Independent System Operator (CAISO)

In response to legislation in California that established an RPS, the California Energy Commission (CEC) and California Public Utilities Commission established a team to examine the integration costs of all existing renewable power sources in the state. The analysis of wind generation was based on the three main California wind resource areas—Altamont, San Gorgonio, and Tehachapi—for 2002. The contribution that wind (and the other renewables) makes to system variability was estimated and CAISO regulation prices were used to estimate the cost of wind's regulation impact. The maximum regulation costs were $0.46/MWh of wind generation, but varied somewhat depending on the resource area.

To estimate the impact on the load-following time scale, data on system load and renewable generation were analyzed. The energy market operated on a 10-minute interval during the study period. The analysis focused on potential distortions to the dispatch stack that would result from swings in renewable generation. However, because of the numerous conventional generators available for redispatch, no measurable impact was found.

Unit commitment is not the responsibility of the CAISO. Once bids have been accepted, generators assume this responsibility, and associated costs are assumed to be reflected in bids. Hence, the impact of wind variability on costs in the unit-commitment time frame was not assessed.

Capacity value for wind was 23%–25% of rated capacity. However, because discrepancies surrounded the actual installed capacity, these values are felt to be somewhat imprecise. Capacity value was sensitive to hydro dispatch, interchange schedules, and conventional unit maintenance schedules. The Phase I and Phase III reports discuss these and other results.

During the analysis, several data anomalies were uncovered. Most data were obtained from the CASIO plant information (PI) database, which records massive quantities of power system data from various metering systems. Because of the large volume of data, the PI data are fed through a compression algorithm to save storage space. Some irregularities in the system data suggested that the compression algorithm may have artificially smoothed some of the high-rate (1-second) data. During early parts of Phase III, some additional anomalies appeared in some data sets during data dropouts. The automatic data correction algorithms appeared to interpolate between good data points even if the dropout period spanned long periods of time (in some cases, several months). Additional data were obtained from the utilities to address these issues and were incorporated in a subsequent multi-year study (below). The Phase III report made specific recommendations for quality assurance and testing of data that would be critical to assessing the impact of wind and other renewable energy technologies as penetration continues to increase on the CAISO system.

A multiyear study of the RPS integration cost that covers 2002–2004 is complete and is presently under review by the CEC. This final project report will be released very soon. An additional, separate study is also underway to analyze the operational issues that would be posed by higher penetrations of wind than are on the California system. This study is on behalf of the CEC, managed by Kevin Porter, Exeter Associates, with principal analytic work by GE Energy, Davis Power Consultants and AWS TrueWind. Results are anticipated in late 2006. This new study will analyze the impact of wind from a market-based approach, and is anticipated to be similar to the NYISO study that was carried out by GE Energy in New York, as discussed below.

New York Independent System Operator (NYISO)

This work, completed in early 2005, was conducted by GE Energy for the NYISO with primary support from the New York State Energy Research and Development Authority (NYSERDA). Wind resource projections were provided by AWS TrueWind. The project was motivated by an RPS that may result in some 3,000 MW of new wind generation in New York within the next ten years. In light of wind's natural variability, the NYISO wanted to understand the impacts of a substantial amount of wind generation on the operation of the New York electric power network. The study addressed 3,300 MW of wind in a system that serves a customer load projected at about 34,000 MW in the 2008 study year. The key question was whether the system would be able to handle 10% wind penetration without major difficulties. Figure 4 shows the relative locations of wind plants used in the analysis.

This study is the most comprehensive U.S. wind integration assessment conducted to date. It encompassed all the time frames discussed above, and estimated system operating costs, impacts on customer payments, reductions in emissions from conventional power plants, and the impacts of wind forecasting. The New York system is operated as a single large balancing authority, and has well-functioning hour-ahead and day-ahead wholesale markets into which generators bid energy. Bids are accepted until projected demand is met on an hour-by-hour basis, and all accepted bidders—including wind plants, which bid at zero price—are paid the highest accepted bid price.

This study has estimated wind's total cost impact on the operation of the system. Increases in costs associated with regulation, load following, and generation scheduling that stem from wind's variability are combined with savings resulting from fossil fuel displacement. The wind resource was modeled from weather data for the period 2001 and 2002, and was combined hourly with corresponding coincident load and generation data scaled to the projected 2008 peak demand. Geographic diversity of the wind was captured by using wind data that corresponded to a number of locations. Figure 5 shows an hourly trace of wind generation and load for one week.

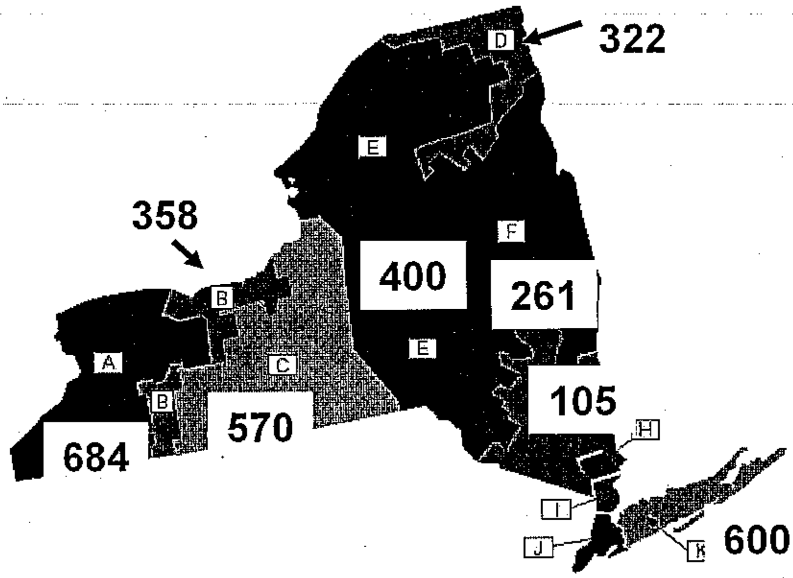

Figure 4. Location of NY wind plants from NYISO/GE Study

The overall conclusion from the study was that the New York State power system can reliably accommodate at least 3,300 MW (10%) of wind generation with only minor adjustments to its planning, operating, and reliability practices. No increase in spinning reserve would be required, and 36 MW of additional regulation would be needed to maintain frequency at the no-wind level. The total impact on variable operating costs for the study year—including impacts of wind variability and fuel savings—was a reduction of $335 million. Fuel displaced by wind was primarily natural gas, which was conservatively priced at $6.50–6.80/MMBtu. Total system variable cost savings increase from $335 million to $430 million when state of the art forecasting is considered in unit commitment. Perfect forecasting provided an additional benefit of about $25 million.

Reductions in load payments ranged from $515 million to $720 million, with higher savings resulting from state of the art forecasts. Revenue paid to the wind generators was $305 million, or about $0.035/kWh. This amount is consistent with the terms of typical power purchase agreements between wind plant owners and purchasing utilities that were in effect during the study period. This indicates that wind offers a viable business opportunity in New York.

A loss of load probability approach was used to calculate the capacity credit of wind. A unique feature of the analysis was the recognition of the transmission constraint between some wind areas and load areas. Average on-shore capacity value was about 9% of rated capacity, and off-shore was 36%.

__Xcel Energy West (Colorado)__
The EnerNex-WindLogics team is conducting this study for Xcel Energy's Public Service of Colorado unit. Wind penetrations of 10% and 15% have been studied, and a 20% case was performed by scaling up the 15% wind generation case (this scaling likely overestimates the additional variability imposed by wind on the power system). The methodology is similar to that employed in the MN DOC study, although an additional element was required to assess the impacts on gas purchases, consumption, and storage. Traditionally, gas decisions must be made—and lived with—every day. As a result, higher penetrations of wind are likely to require additional gas storage, which results in an

additional cost impact from wind's variability. As in the Minnesota study, the intra-hour load-following cost was negligible, and the major impact was related to differences between the hour-by-hour commitment schedule and the net of load and wind.

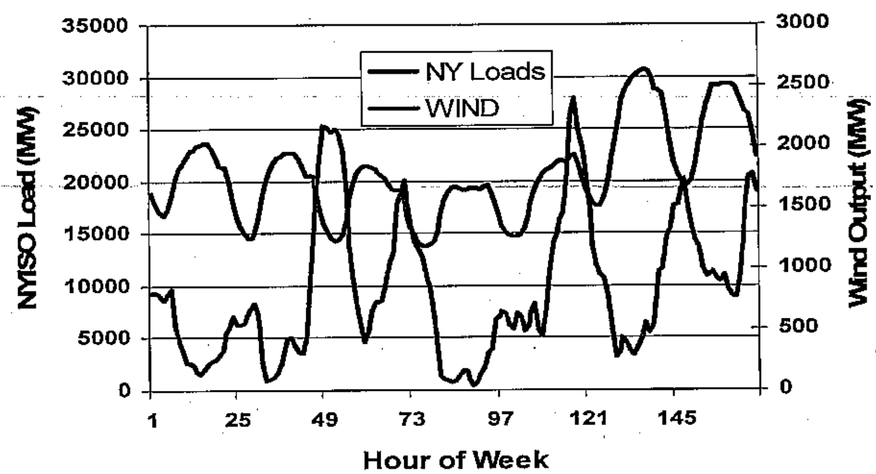

Figure 5. One week of load and wind generation from NY study

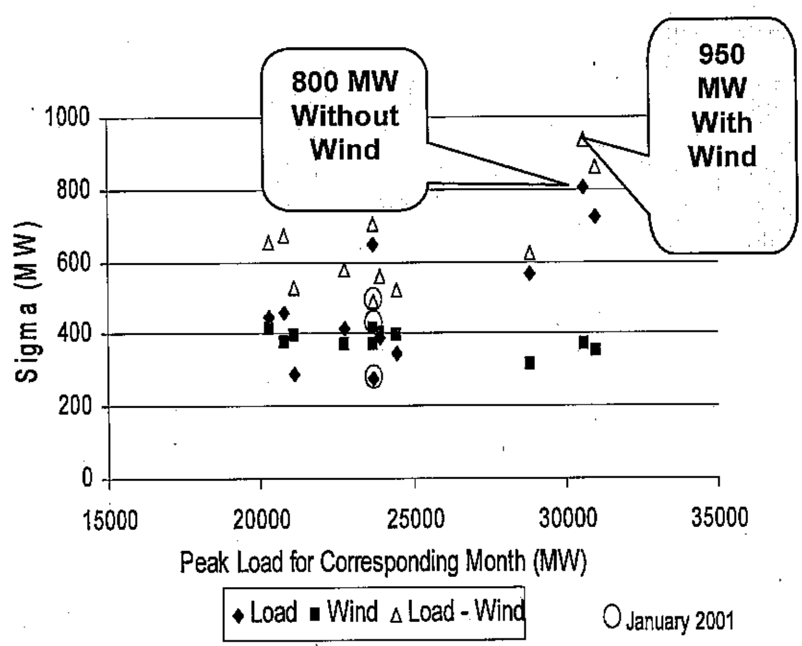

Figure 6. Standard deviation of day ahead forecast errors in NY

Another interesting aspect of this study is the 300 MW pumped-storage unit in Xcel's service territory. At 10% wind penetration, the flexibility offered by the pumped storage unit reduced the integration cost by $1.30/MWh.

Figure 7 shows the region in Colorado that was used for prospective wind plant locations, and Table 1 illustrates some of the results from the integration cost study.

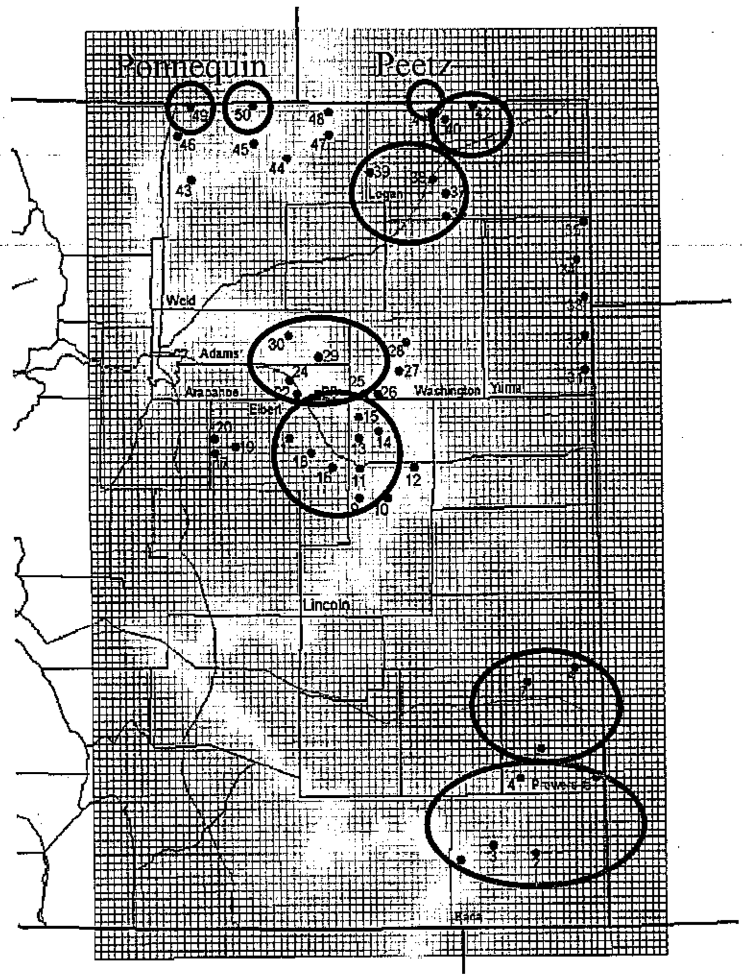

Figure 7. Region for wind plants in Xcel Energy West study

Table 1. Results from Xcel Energy West integration study

Penetration Level	10%	15%	20%[2]
Hourly Analysis	$2.26/MWh	$3.32/MWh	$6.57/MWh
Regulation	$0.20/MWh	$0.20/MWh	$0.20/MWh
Gas Supply (1)	$1.26/MWh	$1.45/MWh	$2.10/MWh
Total	**$3.72/MWh**	**$4.97/MWh**	**$8.87/MWh[2]**

Table Notes:
(1) Costs include the benefit of additional gas storage
(2) Rough results obtained from scaling wind from the 15% case

The Xcel Energy West study provides additional useful insights relative to natural gas supply and management. The additional gas storage required to accommodate wind's variability and uncertainty would provide a winter-summer seasonal hedging benefit to the system of about $1.00/MWh of wind energy at 15% penetration. And in a much more extensive assessment of wind's role in hedging against swings and spikes in natural gas prices, researchers at Lawrence Berkeley National Laboratory find wind energy hedge values of about $5.00/MWh of wind [11].

Results Summary and Discussion

Key results from these and other studies are summarized in Table 2:

Table 2. Wind impacts on system operating costs

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May 03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep 04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
July 04	CA RPS Phase III	4	0.46 (1)	na	Na	na	na
June 03	We Energies	4	1.12	0.09	0.69	na	1.90
June 03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.6
April 06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April 06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
April 06	Xcel-PSCo (2)	20	0.20	na	6.57	2.10	8.87

Table Notes:
(1) Represents maximum regulation cost for all wind resource areas
(2) Preliminary results based on scaling wind generation from the 15% case, therefore likely overestimates cost impacts

The results in Table 2 show that the ancillary service impacts of wind from the recent studies are in line with studies that we have previously examined [6]. The Xcel studies represent significant steps forward in the analysis, by using detailed wind profiles developed to represent the wind behavior coincident with load. The Xcel Energy West study illustrates that there is not a one-size-fits-all answer to the wind integration question, and applies a method to analyze the impacts on a gas-constrained system where gas purchases are made in advance. The California multiyear study applies the methods to three years of data that were collected by the ISO and utilities that purchase the wind output. All this recent work points to the desirability of using multiple years of time-synchronized wind and load data to obtain more robust results.

Capturing the spatial variations of wind—both within an individual wind plant and across the entire region considered—is also important, since these variations significantly mitigate impacts.

Conclusions and Insights

Given the work that has been done, several conclusions are emerging. Although wind imposes additional operating costs on the system, these costs are moderate at penetrations expected over the next 5–10 years. These results are expected to apply as additional wind generation is developed in the next few years in response to state government RPSs, although wind integration costs will increase with penetration.

Large, diverse balancing areas with robust transmission tend to reduce wind's impact and ancillary service cost. At current U.S. levels, the impact on regulation and load following appear to be modest, and the unit commitment time scale appears to be more important. In this time scale wind forecasts can play a more prominent role, and improvements in forecasting technology will certainly mitigate wind's integration costs. As wind penetration increases in the United States, better forecasting is expected to play a more important role. To be effective, forecasts do not need to be perfect, although increasing accuracy tends to reduce costs. It is possible that at some point the incremental cost of forecast improvements will outweigh the incremental benefits that accrue from increased accuracy.

Aside from large balancing areas, other factors can mitigate wind impacts. If several adjacent balancing areas can develop cooperative arrangements or markets for ancillary services, larger quantities of wind could be absorbed because of the greater load and wind diversity that would be expected across broader regions. This could be captured by larger balancing areas, but other means of tapping this potential can be used. This is discussed further by Kirby and Milligan [7].

There is also some evidence that system operators will become more familiar with wind after working with it. For example, The Western Farmers Electric Cooperative (WFEC) in Oklahoma recently performed an analysis with the National Renewable Energy Laboratory of the operational impact of wind on its system. WFEC has a peak load of 1,400 MW and installed wind capacity of 74 MW. Initially the system operators could not maintain the CPS-1 frequency standard at its pre-wind level. With experience they became familiar with the wind system and brought CPS-1 into its pre-wind range [13].

Emerging Best Practices and Methods

Although there are differences between studies, there appears to be some convergence on techniques and methods used to analyze wind's ancillary service impacts. A key point is to recognize that the entire system—not individual loads or generators—need to be balanced. In the United States, this balance does not need to be perfect, but is required to fall within the statistical limits defined by CPS-1 and CPS-2. The implication for wind integration is profound: not every movement in wind generation needs to be matched one-to-one by another conventional generator.

The approaches used in recent studies generally capture the important system characteristics through detailed modeling of the relevant grid and operational practices. These representations of the system can then be simulated in a chronological environment that can observe the detailed constraints on the system that are imposed by loads and generators.

Because wind impacts occur throughout the time domain, the coincidence of loads and wind generation must be captured. Because wind speed and wind generation data are often difficult or impossible to obtain for desired time periods, an emerging approach is to construct the wind data from detailed time-calibrated mesoscale meteorological modeling for the desired time period. Normally this is accomplished by selecting load data for the study period based on recent historical data. Wind data sets can then be constructed to match the historical load period. And because wind impacts on some longer time scales may differ from year to year, the best approach is to extract multiple years of wind data that correspond to the loads in a multiyear study period, and complete several years of detailed simulations. This picks up any correlation (which may be highly nonlinear with significant phase shifts) between wind and load, and improves confidence that the results are meaningful.

Detailed meteorological modeling also allows the geographic impacts of wind to be represented as the turbines are spread over small areas (within a wind plant) or large areas (several wind plants) and picks up the impact of prevailing weather patterns that drive the wind generation and influences load.

The short-term behavior of wind power plants has been quantified by Wan [8]. The data sets indicate that wind power variability is quite low at fast time frames, and increases at progressively longer time frames. As a practical matter, this implies that wind's impacts will be relatively small in the regulation time scale, increase at the load following time scale, and become even more significant at the unit commitment/scheduling time scale. The U.S. studies broadly support this conclusion, and as more wind operating data become available, a more realistic representation of wind in the analytic models can be captured so the results are more accurate.

Within the modeling frameworks used in the U.S. studies, the variability of wind generation is added to the already considerable variation in load. The analytic tools approximate the view of the system as seen by the operator. This implies that the statistical treatment of the wind and load time series is important and provides a realistic representation of wind's impact on the regulation and load following time frames.

To better understand the role of forecasting, some studies have constructed wind forecasts and run the analysis with and without the forecasts. Clearly forecasting can play an important role in mitigating wind's impacts on system operations and costs, but only if the forecast is used appropriately in the control room.

Remaining Questions and Future/Ongoing Work

In spite of significant progress in understanding wind's impact on the grid, questions remain. Current systems can apparently handle wind penetrations up to 10%–20% based on capacity, but the costs appear to increase with penetration. Models, analytic tools, and practices have generally not been adapted to extensive experience with large quantities of wind. As wind penetration increases over the next several years in the United States, this increasing cost will provide an increasing economic incentive to investigate cost-mitigation approaches.

Several possibilities for these strategies appear promising, but all require further quantification:

- Dynamic scheduling
- Consolidation of balancing areas
- New operational practices and economic curtailment
- Better use of flexible resources, including dispatchable hydro and pumped storage
- Plug-hybrid electric vehicles with smart-charge controllers that can provide demand and supply to the grid
- Hydrogen and other forms of energy storage
- Aero derivative gas (jet) engines with quick start capability and good heat rates
- Price-responsive load
- Integration of wind forecasting into the control room
- Learning how to best operate the system with large wind power plants

This list is not exhaustive, nor are the items on the list mutually exclusive. Some combination of these items may significantly increase the ability of the grid to absorb increasing quantities of wind generation.

Future and Ongoing Work in the United States

In Minnesota a project to evaluate the grid impacts of 20% wind by energy (5 GW of wind) has recently begun. This project resulted from legislation, and is on behalf of the Minnesota Public Utilities Commission. EnerNex is the contractor; WindLogics provides the meteorological data foundation. The study will also examine the new MISO market structure, examine transmission and mitigation strategies, and compare market and reliability rules. Anticipated completion date is November 2006.

In response to the 2004 Xcel Renewable Development Fund solicitation in Minnesota, a team led by WindLogics, including EnerNex, AREVA T&D, and the Utility Wind Integration Group, was awarded a grant of nearly $1 million to research and demonstrate a utility-scale wind power forecasting system for the Xcel North system. The goal of this project is to define, design, build, and demonstrate a complete wind power forecasting system for use by Xcel system operators. This project will begin in 2006 and builds on other studies that the development team has performed for Xcel to quantify the cost of ancillary services for wind plants on the Xcel system.

Key objectives will be to optimize the way wind forecast information is integrated into the control room environment (for both load-following and unit commitment time scales) and to evaluate the impact of the wind forecast on control room operations. A critical part of the process will be to define the types of wind forecasts, delivery mechanisms, and method of control room integration that will be most useful in day-to-day activity.

In California the Intermittency Analysis Project is evaluating the system impacts of 5 GW wind by 2010, possibly up to 15% (rated capacity to peak) or greater by 2020. Some items to evaluate include periods of high wind and low load, and the study may develop a scenario that aggressively pushes the amount of wind on the system to higher levels. The study primary contractors are Davis Power Consultants, GE Energy and AWS Truewind. The study will be completed by the end of 2006.

There are also several projects that involve smaller systems. The Sacramento Municipal Utility District is embarking on a study of high wind penetration and will investigate the role of hydro pumped storage. The analysis framework will be the Areva Dispatch Training Simulator (DTS), a software platform that mimics the control room environment of the system operator. Another project that will use the DTS is at the Public Service Company of New Mexico, which has a wind plant that is built along a ridge top. The limited import/export capabilities, the relatively high and increasing wind penetration, and ramping impacts provide an interesting look at mitigation strategies, particularly during minimum load/maximum wind time periods. Idaho Power and Grant County Public Utilities Department also have projects to evaluate wind integration in systems with constrained hydro resources.

Other larger scale studies are also underway in the United States. Because of limited transmission interconnections in parts of the Midwest and West, several transmission organizations have begun to analyze wind scenarios in the framework of subregional and regional reliability areas. These studies generally collaborate with the utilities and load-serving entities in the region, and with other stakeholders. Example studies are underway at the Seams Steering Group of the Western Interconnection (in process of transferring to the Western Electricity Coordinating Council), Northwest Transmission Assessment Committee, Southwest Area Transmission, and MISO. The Rocky Mountain Area Transmission Study (RMATS) completed Phase I of a similar project in 2005. There has also been a high level of interest in examining transmission tariffs to assess the role of tariff reform, partly growing from the RMATS work, and partly from interest in the Northwest by PacifiCorp, Bonneville Power Administration, and the Renewable Northwest Project. The FERC has indicated interest in this topic, and we expect further activity in the near future.

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