Utility Wind Integration and Operating Impact State of the Art

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***Abstract*—In only six years, from 2000 to 2006, wind energy has become a significant resource on many electric utility systems, with nearly 74 000 MW of nameplate capacity installed worldwide at the end of 2006. 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) published a special issue of its *Power & Energy Magazine* that focused on integrating wind into the power system. This paper provides a summary and update on many of the salient points from that special issue about the current state of knowledge regarding utility wind integration issues.**

***Index Terms*—Wind ancillary service impacts, wind energy, wind integration.**

I. Introduction

THE United States is experiencing an unprecedented period of wind power growth. The installed wind capacity grew from approximately 9000 MW to 11 600 MW during 2006. This rapid growth rate is the result of many factors, including the federal Production Tax Credit (PTC), state renewable portfolio standards (RPS), and the favorable economic and environmental characteristics of wind energy compared to other forms of energy. Because of this rapid growth rate, utilities with significant wind potential in their service territories have performed studies of the technical and economic impacts of incorporating wind plants into their systems. These studies [1] are providing a wealth of information on the expected impacts of wind plants on power-system operations planning and valuable insights into possible strategies for dealing with them. The case studies summarized here address early concerns about the impact of wind power's variability and uncertainty on power system reliability and costs.

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Wind resources can be managed through proper plant interconnection, integration, transmission planning, and system and market operations. Accordingly, this paper is divided into four sections: wind plant interconnection issues, wind plant operating impacts, transmission planning and market operation issues, and accommodating increasingly larger amounts of wind energy on the system.

On the cost side, at wind penetrations of up to 20% of system peak demand, it has been found that system operating cost increases arising from wind variability and uncertainty amounted to about 10% or less of the wholesale value of the wind energy [2]. This finding will need to be reexamined as the 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 the makeup and the operating strategies of the power system. 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. These incremental costs, which can be assigned to wind-power generators, are substantially less than the imbalance penalties generally imposed through Open Access Transmission Tariffs under Federal Energy Regulatory Commission (FERC) Order No. 888 [3]. A variety of means, such as commercially available wind forecasting and others discussed in this paper, can be employed to reduce these costs.

Further, there is evidence [6] 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. Because wind is primarily an energy source, not a capacity source, no additional generation needs to be added to provide backup capability, provided that existing generation remains in service and wind capacity is properly discounted in the determination of generation capacity adequacy. However, wind generation penetration may affect the mix and dispatch of other generation on the system over time because 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 vary from 10% to 40% of a typical project's nameplate rating, depending on local wind characteristics and coincidence with the system load profile [7]. Wind generation may require system operators to carry additional operating reserves. Given the existing uncertainties in load forecasts, these referenced 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.

There is a significant body of analysis that has emerged on wind interconnection and wind integration impacts in the United States and in Europe over the past few years. Although this paper focuses on the United States, many of the European reports are summarized in Holttinen *et al.* [4] and Gross *et al.* [5]. Although review of these studies is beyond the scope of this paper, the European results and insights are consistent with the U.S. studies examined here.

II. Wind-Plant Interconnection

The early history of large wind-plant interconnection to utility systems in the United States began in California in the 1980s. Special care was taken to design and protect the interface between the wind plant and the utility system to minimize any interference with the operation of the power system as a result of any problems with the wind plant. Common practice during a system disturbance was to disconnect the wind plant and not reconnect it until the system was returned to a normal state of operation. This occurred frequently in the early years of application until a base of operating experience was built and a level of confidence gained by the operators.

By the mid-1990s, the development of large wind generation facilities spread outside California to Texas and the upper Midwest. Increasing plant sizes began to cross the threshold for standard interconnection evaluations, including short-circuit studies and stability studies. Because individual control area penetration was still small, the studies were often more of a formality, with machine models that were generic and not verified. As wind capacity continued to grow and plant sizes of several hundreds of megawatts were realized, questions were raised that could no longer be neglected. Individual plants were becoming comparable in size to conventional fossil fuel plants, and the loss of a single plant had to be considered in utility reliability evaluations.

Concentrations of wind capacity in southern California and western Texas, in relatively weak parts of the system, led to voltage stability concerns that needed to be addressed with more rigorous machine models and analysis techniques. The early dominance of the direct-connected induction generator aggravated the voltage-control problem and focused industry attention on the reactive power and voltage-control issues. There was a growing recognition that wind plants needed to be treated and analyzed like conventional power plants. Initially the industry reacted by building simple induction-machine models for wind power plants using industry standard software packages like PSS/E and PSLF. The models were used to perform the standard transmission planning studies, even as variable-speed machines with more sophisticated power electronic controls became available. As long as the wind plant was studied at a strong point in the system, no problems were observed, but when a more capable machine was proposed for a weak point in the system, the simplified models failed to show the additional benefits of the new technology.

Concurrently, similar trends were occurring in Europe, which led to the development and adoption of early grid codes for the interconnection of wind plants to the utility system. The first grid codes were focused on the distribution level, as that was where the bulk of the wind turbines were connected. After the blackout in the United States in August 2003, the United States wind industry took a proactive stance in developing its own grid code in recognition of the perceived shortcomings in the power-plant interconnection order of FERC, Order 2003, issued in July 2003, and the fact that wind plants had to do their part in contributing to stable grid operation.

The American Wind Energy Association (AWEA) led the effort in the United States. After a FERC Grid Code Technical Conference in September 2004, AWEA filed its grid code with FERC, which formed the basis for the United States grid code for wind plants, currently embodied in FERC Order 661A, issued in December 2005.

The grid code includes a number of important concepts, including a requirement for low-voltage ride-through (LVRT) in the event of system faults. The generator must stay online during a three-phase fault for normal fault clearing time up to nine cycles, and single line-to-ground faults for delayed fault clearing times, during a voltage dip as low as 0.15 p.u. at the high side of the generator step-up transformer for units placed in service before 2008. The voltage dip requirement is extended to 0.0 p.u. beginning in 2008. The grid code also includes a requirement for reactive power control of ± 0.95 at the point of interconnection when shown to be necessary as a result of a system study, a requirement for accurate plant models to be provided for study purposes, and the need to supply SCADA data as agreed with the transmission service provider.

While wind power plant terminal-behavior is different from that of conventional power plants, it can still be compatible with the design and operation of existing power systems. The grid code requirements embodied in FERC Order 661A are being met routinely by commercial wind plants entering service today, either through the inherent capability of the wind turbine technology being deployed or through the addition of suitable terminal equipment, such as some combination of static and dynamic shunt compensation. Additional requirements that are being met when requested include voltage control, output control, and ramp rate control. Increased demands will be placed on wind plant performance in the future. 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).

The rapid proliferation of machine types has brought with it a corresponding proliferation in machine and plant models. Many of these models have not been tested and verified. Better dynamic models of wind turbines and aggregate models of wind plants are needed to perform more accurate studies for transmission planning and system operation. An effort is underway through the Western Electricity Coordinating Council (WECC), in cooperation with the IEEE and the Utility Wind Integration

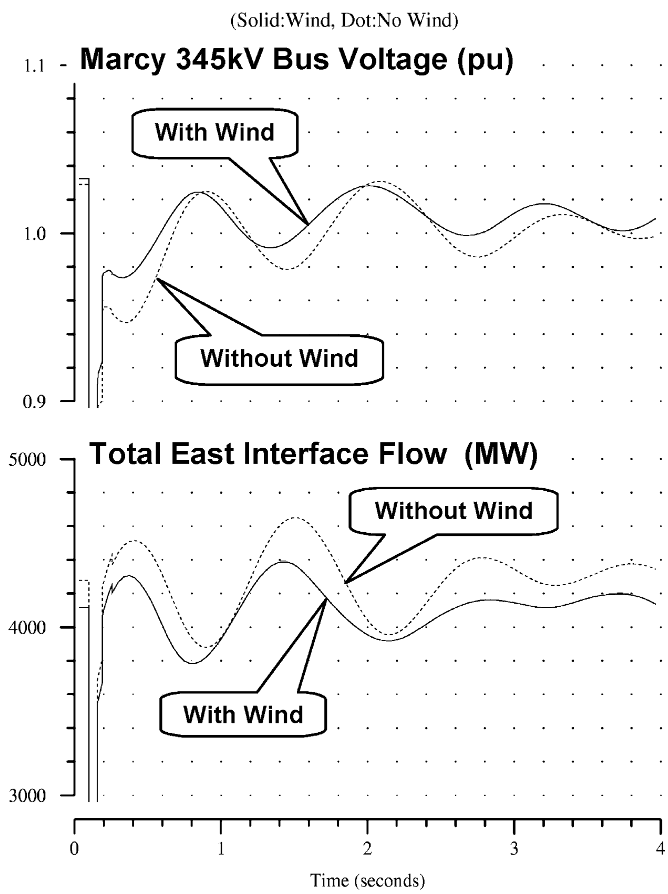

Fig. 1. Impact of wind generation on system dynamic performance [6].

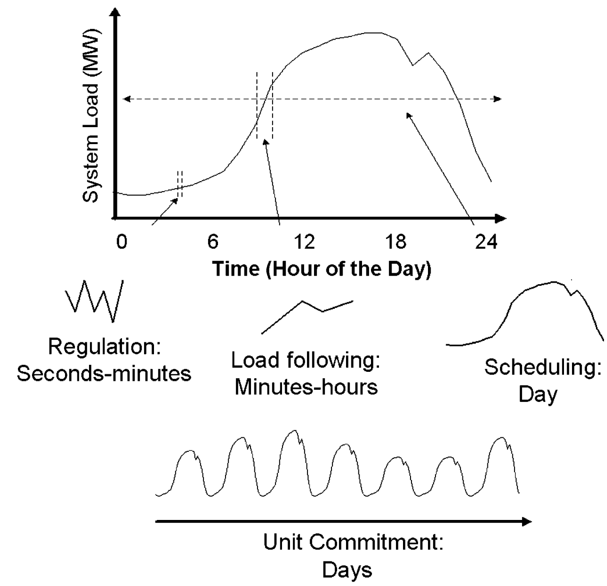

Fig. 2. Time scales for grid operations [1].

Group (UWIG), to develop a generic set of models for the four major machine types to simplify the task of maintaining an ever-increasing number of complex machine models.

The ability of modern variable-speed wind turbines with power electronic controls to assist in improving the power system performance is now beginning to be explored in some detail. Not only can modern wind plants be added without degrading system performance, they can also contribute to improvements in system performance.

System stability studies [6] 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. This is illustrated in Fig. 1 for a simulation of a normally cleared three-phase fault on a critical 345-kV bus in New York State. The simulation assumed a 10% wind penetration (3300 MW on a 33 000-MW system) of doubly fed induction machines with vector control [6]. Actual wind-production data and sophisticated mesoscale weather modeling techniques, which will be discussed in more detail below, are needed to address reliability. Studies [9] have shown that 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 as a result of a loss of wind is not a credible event. This is an important consideration for first contingency evaluation.

III. Wind Plant Integration Operating Impacts

Several wind plant integration studies have recently been performed in the United States [1]. The general approach is to carefully evaluate the physical impacts of wind on the grid and then calculate the cost impacts that result. Some parts of the United States have robust wholesale power markets, whereas other parts of the country retain significant elements of the regulated monopoly structure. Therefore, integration studies must be assigned the relevant context, depending on the situation.

A key element of a wind integration study involves obtaining a wind data set that realistically represents the performance of an actual wind power plant. Because most of these studies are done on a prospective basis, wind data are often not available at the outset of the study. Weather is clearly a significant driver both for electric load and for wind generation. A state-of-the-art wind-integration study typically devotes a significant effort to obtaining wind data that are derived from large-scale meteorological modeling that can re-create the weather corresponding to the year(s) of load data used. Typically, a series of virtual anemometers are selected to represent the location of the potential wind power plant. Because of the geographic smoothing that occurs within the wind plant, each of these virtual anemometers will typically represent no more than 30 to 40 MW of wind capacity. Therefore, a large number of these extraction points are necessary to adequately represent the wind that is input to the power-production calculations [8]. Wan has performed extensive work analyzing actual long-term wind plant output data sets [9].

Regardless of the power market structure, most studies divide the wind impacts into the time frames that correspond to grid operation. Fig. 2 illustrates these time scales.

No hard and fast boundary separates them, but these time scales correspond to actions that must be taken by the system operator to maintain system balance. Note that European definitions vary somewhat from those in the United States. Regulation services provide maneuverable capacity to the system on short time scales so that system balance is maintained. This typically occurs over a few minutes and is provided by generators on automatic generation control (AGC). Load following includes both capacity and energy services and is generally 10 min up to several hours. This time scale incorporates the morning load pickup and evening load drop-off. Scheduling and unit commitment ensure that sufficient generation will be available when needed, over several hours or days ahead of the real-time schedule.

The system operator will schedule sufficient spinning and non-spinning reserves so that unforeseen events do not endanger system balance within the control performance standards prescribed by the North American Electric Reliability Council (NERC). Because wind and load are generally uncorrelated in short time scales, the regulation impact of wind has been found to be modest. In two recent wind integration studies performed in the United States, the addition of 1500 MW and 3300 MW of wind (15% and 10%, respectively, of system peak load) increased the regulation requirements by 8 MW [10] and 36 MW [6], respectively.

The load-following impacts of wind are analyzed from the point of view of the system operator, who is tasked with the responsibility of maintaining system balance. The net load that must be served after accounting for wind has more variability than the load alone, but it is not necessary nor is it economic to counter each wind movement with a corresponding movement in a load-following unit. The net increase in variability is less than the isolated variability of the wind alone. Every system study we are aware of in the United States has found the distribution of changes in net load to flatten and broaden with large-scale wind added to the system, although the specific details vary. Fig. 3 illustrates this impact from the Minnesota Xcel study, completed in 2004 [10]. The graphs show more high-ramp requirements with wind than without wind and a general reduction in small-ramp requirements compared to the no-wind case. The implication is that high wind penetrations will likely increase the ramp requirements for many hours of the year.

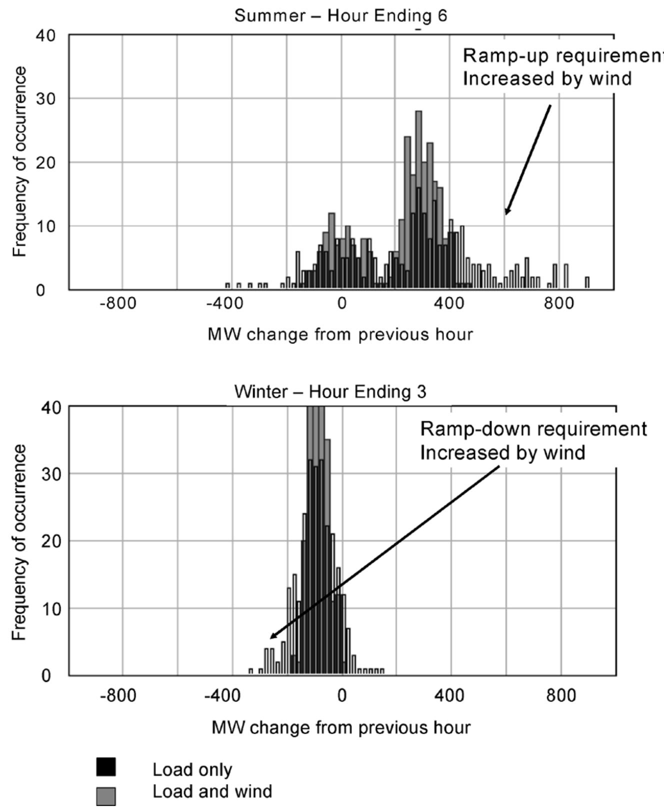

Fig. 3. Load following impact of wind. Black shows no-wind case; gray shows net load and wind [10].

In addition to the greater variability that wind imposes on the system, there is also an increase in the uncertainty introduced into the day-ahead unit-commitment process. The impact of these effects have been shown to increase system operating cost by up to $5.00/MWh of wind generation at wind capacity penetrations up to 20% to 30%. However, this increase in cost depends on the nature of the dispatchable generation sources, their fuel cost, market and regulatory environment, and the characteristics of the wind-generation resources as compared to load. Handling large output variations and steep ramps over short time periods (for example, within the hour) could be challenging for smaller balancing areas. Table I shows the integration cost results from the major studies recently undertaken in the United States.

Commercially available wind-forecasting capability can substantially reduce the costs associated with day-ahead uncertainty. In one major study [6], state-of-the-art forecasting was shown to provide 80% of the benefits that would result from perfect forecasting. Implementing wind-plant-output forecasting in 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. Advanced forecasting systems can help warn the system operator if extreme wind events are likely so that the operator can maintain a defensive system posture if needed.

Wind energy can reduce the combustion of fossil fuels and can serve as a hedge against fuel price risk and potential emissions restrictions. Because wind is primarily an energy resource and because individual loads and generators do not need to be balanced, there is no need for backup generation for wind. However, wind provides additional planning reserves to the system, and this can be calculated with a standard reliability model. The effective load carrying capability (ELCC) is defined as the amount of additional load that can be served at a target reliability level with the addition of a given amount of generation. The ELCC of wind generation can vary significantly and depends primarily on the timing of the wind energy delivery relative to times of high system risk [defined as loss of load probability (LOLP) or similar metric]. Capacity for day-to-day reliability purposes must be provided through some combination of existing market mechanisms and utility unit-commitment processes. The capacity value of wind has been shown to range from approximately 10% to 40% of the wind-plant-rated capacity (see Table II). In some cases, simplified methods are used to approximate the rigorous reliability analysis [7].

IV. Transmission Planning and Market Operation

Good wind resources are often located far from load centers. Although current transmission planning processes can identify solutions to the transmission limitations, the time required for

TABLE I
WIND INTEGRATION COSTS IN THE UNITED STATES

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 [9]	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep 04 [7]	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
June 06 [10]	CA RPS Multi-year Analysis	4	0.45	na	na	na	na
June 03 [11]	We Energies	4	1.12	0.09	0.69	na	1.90
June 03 [11]	We Energies	29	1.02	0.15	1.75	na	2.92
May 2005 [12]	PacifiCorp	20	0	1.6	3.0	na	4.6
April 06 [13]	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April 06 [13]	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97

TABLE II
WIND CAPACITY VALUE METHODS USED IN THE UNITED STATES [7]

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s)
PJM	Peak Period	Jun-Aug HE 3 p.m. - 7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4 p.m. to 6 p.m., Jul (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26 to 34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (30%), Full ELCC study using 10-year data has begun; Xcel using MAPP approach (10%) in internal work
RMATS	Rule of thumb	20% all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%). New Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
PGE		33% (method not stated)
Idaho Power	Peak Period	4 p.m. to 8 p.m. capacity factor during July (5%)
PSE and Avista	Peak Period	PSE will revisit the issue (lesser of 20% or 2/3 Jan C.F.)
SPP	Peak Period	Top 10% loads/month; 85th percentile

implementation of solutions often exceeds wind-plant permitting and construction times by several years. Transmission planning processes in the United States have evaluated many potential wind development scenarios and have proposed transmission solutions. Examples include the recent project to support the Western Governors' Clean and Diverse Energy Plan [16] and the creation of Competitive Renewable Energy Zones (CREZ) in Texas.

Because of the increased variability and uncertainty that wind brings to the system, transmission system tariffs have not always kept pace with the rapid development of wind in the United States. FERC Order 888, issued in 1996, included a tariff for imbalance. Because the objective of the tariff was to discourage gaming by conventional generators, it included penalty charges if generators produced outside of a bandwidth prescribed by the tariff. Because wind generation depends on nature, it is not subject to potential gaming in the same way. For that reason, a cost-based imbalance tariff seems to be more appropriate for wind than a penalty-based tariff. This would provide an incentive for the wind operators to improve wind forecasts and to make sure the forecast is made available to the system operator in a timely fashion. Market products and tariffs should properly allocate actual costs of generation energy imbalance to all entities, not just wind. FERC recently issued a Notice of Proposed

Rule (NOPR) that would widen the bandwidth for renewable intermittent/variable generation that would move most wind imbalance to a cost-based payment.

Markets with well-functioning day-ahead and hour-ahead markets provide an effective means to address wind variability. This is demonstrated by the New York study that was carried out by GE [6]. The large liquid market has resources that are available for the increased regulation and load-following impacts of wind generation. The ability for wind to revise its schedule close to the operating hour can also provide improved information to the system operator and help minimize imbalance issues and improve reliability.

There may be times that a balancing authority is unable to take wind energy into the system. This could happen during low-load periods if wind is generating near its maximum output. It is also possible that large wind penetrations in a system could contribute to system ramp events that are difficult to follow. In cases like this, it might be economically efficient to impose limited ramp-rate or energy control on the wind farm. Further work is needed to quantify these issues.

Small balancing areas can have more difficulty maintaining system reliability with high wind penetrations. This is because the resource base is small, and the system granularity makes the relative variability of wind harder to manage. Broadening the size of the balancing authority, improving access to nearby markets, or finding other solutions like dynamic scheduling or area control error (ACE) sharing would help improve reliability.

There has also been considerable interest in examining the efficient use of the existing transmission system. Efforts that evolved from the Seams Steering Group, Western Interconnection [17] (SSG-WI) began to analyze key path loadings and to quantify the times that the path was near capacity. Further analysis was carried out as part of the Rocky Mountain Area Transmission Study (RMATS) [18] and included an analysis of one key path in the West to determine whether existing physical transmission could deliver wind to market even if no available transfer capability (ATC) were available [19]. This helped stimulate further thinking about transmission utilization and potential new transmission products that could best be characterized as flexible firm. Although details have not been well defined, this would resemble a firm transmission product but with some level of potential curtailment that would be capped at an agreed-upon level by the buyer and seller. The recent FERC NOPR also addresses the calculation of ATC: "The NOPR proposes to improve transparency and consistency in several critical areas, such as the calculation of ATC. The NOPR proposes to direct public utilities, under the auspices of the North American Electric Reliability Council (NERC) and the North American Energy Standards Board (NAESB), to provide for greater consistency in ATC calculation" [3]. It is clear that many parties are interested in pursuing more efficient use of the transmission system. Although this can benefit wind, it will also benefit the power industry and customers in general.

V. Accommodating More Wind in the Future

Power system planners are expending significant effort to determine how much wind capacity can be added to a system before some sort of operating limits are reached or before reliability concerns are encountered. The interconnection and integration study work done to date has shed a fair amount of light on the subject. Existing studies have explored capacity penetrations of up to 20% to 30% and have found that the primary considerations are economic, not physical. The question is one of dealing with the increased variability and uncertainty introduced by the presence of the wind generation on the system.

Additional studies are underway looking at energy penetrations of 20% to 30%, in response to state-level RPS requirements. Such studies are being conducted in California, Colorado, Wisconsin, and for the Midwest Independent System Operator (MISO) footprint. For a given footprint, the capacity penetration is related to the energy penetration by the ratio of the system load factor to the wind plant capacity factor. For a system looking at a 20% wind-energy penetration, with a load factor of 60% and an average wind plant capacity factor of 40%, the capacity penetration would be 30%. These studies underway will shed additional light on the questions associated with the higher penetrations.

In the meantime, a number of insights have been gleaned from the results of the work done to date, as well as the studies in progress. Understanding and quantifying the impacts of wind plants on utility systems is a critical first step in identifying and solving problems. The design and operation of the wind plant, the design and operation of the power system, and the market rules under which the system is operating influence the situation. A number of steps can be taken to improve the ability to integrate increasing amounts of wind capacity on power systems. These include the following:

- **Improvements in wind-turbine and wind-plant models**: Good models are a prerequisite to identifying and solving problems [21].
- **Improvements in wind-plant operating characteristics**: For example, the ability to provide voltage control at a weak point in the system or the ability to provide an inertial response in a stability constrained system can be critical to the reliable operation of the system[6].
- **Improvements in the flexibility of operation of the balance of the system**: As additional wind capacity is added, greater regulation, load-following, and quick-start capability will be required from the remaining generators. The optimum generation mix will vary with the amount of wind on the system [1].
- **Carefully evaluating wind-integration operating impacts**: The magnitude and frequency of occurrence of changes in the net load on the system in the time frames of interest (e.g., seconds, minutes, hours), before and after the addition of the wind generation, must be well understood to determine the additional requirements on the balance of the generation mix [10].
- **Incorporating wind-plant output forecasting into utility control-room operations**: The operating impact with the largest cost is found to be in the unit-commitment time frame. Day(s)-ahead wind plant output forecasting offers significant opportunity to reduce the cost and risk associated with the uncertainty in the day-ahead time frame [22].

- **Making better use of physically (in contrast with contractually) available transmission capacity**: Hourly analysis of line loadings often shows that a line is heavily loaded for a very limited number of hours in the year. Development of a flexible-firm transmission product, which makes the unused capacity available for other transactions when the line is lightly loaded, could be accomplished with minor modifications to current practices [16], [18], [19].
- **Upgrading and expanding transmission systems**: Some of the best wind resources in the country are located in remote areas of the Great Plains and Upper Midwest. New transmission will be required to tap these remote resources and bring them to market. The Energy Policy Act of 2005 (EPACT 2005) is moving forward with identifying new transmission corridors that could help with this problem [20].
- **Developing well-functioning hour-ahead and day-ahead markets and expanding access to those markets**: Operating experience from around the world has shown that a deep, liquid, real-time market is the most economical approach to providing the balancing energy required by the variable-output wind plants. Because of the significant cost introduced into the day-ahead market when a forecast of the wind is not provided, wind plant participation in day-ahead markets is also important for minimizing total system cost [21].
- **Adopting market rules and tariff provisions that are more appropriate to weather-driven resources**: Imbalance penalties that are meant to incentivize the behavior of fossil generators cannot be used to affect the behavior of a wind-driven resource. Weather-driven resources should pay the costs they cause, rather than penalties for behavior they cannot affect [21].
- **Consolidating balancing areas into larger entities or accessing a larger resource base through the use of dynamic scheduling or some form of ACE sharing**: Load and generation both benefit from the statistics of large numbers as they are aggregated over larger geographical areas [23]. Load diversity reduces the magnitude of the peak load with respect to the installed generation, just as wind diversity reduces the magnitude and frequency of the tails on the variability distributions. This reduces the number of hours during which the most expensive units on the dispatch "stack" will be operated and reduces the operating reserve requirement.

In summary, a varied set of options is available to deal with the issues created by increasing penetrations of wind capacity. Additional insights will come from a significant body of work currently underway.

VI. Conclusions

Wind energy has grown from a technology making a very small contribution to the national energy picture to one with the potential to make a much larger contribution. Wind turbines and wind power plants have characteristics that are different from conventional equipment but that are compatible with the current system design. Rapid advances are being made in the design and application of wind power plants as greater understanding of the application requirements develops and increased operating experience is obtained. A significant body of operating experience has been obtained in Europe with 40 000 MW of wind capacity, which serves as a valuable knowledge base for the United States, with 11 600 MW of capacity.

- **Wind Plant Interconnection**: Modern wind plants in excess of 100 MW are routinely being built and interconnected. They are required to provide similar levels of LVRT capability and reactive power control as a conventional power plant. They must also provide SCADA information as required by the transmission service provider. Additional requirements of voltage control, output control, and ramp rate control can be met if required. Machines with power electronic controls have also demonstrated the capability to provide governor response and inertial response. Stability studies using sophisticated models of the doubly fed induction machine have demonstrated the ability of modern wind plants to improve system performance by damping power swings and supporting post-fault voltage recovery. They have also pointed out the need for continued improvements in machine models for dynamic studies.
- **Wind Plant Integration Operational Impacts**: Worldwide experience has demonstrated the need for multiple years of synthetic wind plant output time series data, synchronized with load data for the same time period, to perform utility studies. Data sets for the different time scales of grid operation, including regulation, load following, and scheduling, must be provided for use in conventional utility simulation techniques. The unique characteristics of wind that must be dealt with are the variability and uncertainty in its output. It is increasingly recognized that utilities are used to dealing with both of these characteristics in the load, only to a different degree. An analysis of the net load variability in the different time frames, with and without wind, can give good insight into the additional reserves required to maintain reliable system operation. It is now recognized that the variability of the wind plant output cannot be dealt with in isolation, as it is the net system that needs to be balanced. The issue of uncertainty is increasingly being dealt with through improved wind forecasting techniques. Wind integration studies have shown that wind integration costs of up to \$5 to \$6/MWh of wind energy can be expected for capacity penetrations of up to 20% to 30% of peak load.
- **Wind Capacity Value**: Although the primary benefit of wind power is as an energy resource, it can also provide some capacity value to a system and contribute to a reduction in LOLP. There are well-established techniques using standard reliability models to calculate the ELCC of a wind plant. The ELCC depends primarily on the timing of the wind energy delivery relative to times of high system risk. The capacity value of wind has been shown to range from approximately 10% to 40% of the wind plant rated capacity. Capacity for daily reliability purposes must be provided through some combination of existing market mechanisms and utility unit commitment processes.

- **Transmission Planning and Market Operations**: It is clear that new transmission will be required to move large amounts of remote wind energy to market. Many regional transmission planning studies are underway to investigate the requirements and the changes that must be made to existing rules in recognition of the unique characteristics of wind energy. These changes concern imbalance penalties dealing with the differences between scheduled and actual production as well as a flexible-firm transmission product to enable greater use of existing transmission system capacity that may be contractually, but not physically, committed. There is growing recognition that well-functioning day-ahead and real-time markets provide the best means to deal with wind variability and that aggregation of wind plants over large geographical areas provide an effective mechanism to reduce wind plant variability. Similarly, it is increasingly recognized that large balancing areas can help manage wind plant variability more easily than small balancing areas. System ACE sharing and dynamic scheduling are additional approaches to achieve the same benefits.
- **Accommodating More Wind in the Future**: The insights gained from the ongoing studies and increasing operating experience are providing insights into how to accommodate the increasing wind penetrations of the future. It is clear that understanding and quantifying wind plant impacts on utility systems is a critical first step. This requires good wind plant output and behavior models and good wind plant forecasts. Continuing advances in wind plant operational capability, as well as increased flexibility in the operation of the remainder of the system, are critical for the future. Means to expand the transmission system, as well as make better use of the existing grid, are critically important to accommodate increased amounts of wind power. Developing deep, liquid day-ahead and hour-ahead markets is important to providing a cost-effective mechanism for dealing with wind variability, as is the need to aggregate and balance wind plant output over broad geographical regions. Finally, market rules and tariff provisions more appropriate to weather-driven resources should be adopted.

As additional integration studies and analyses are carried out around the county and around the world, we expect additional insights that will be valuable as wind penetration increases. With the increase in wind installations, actual operational experience will also contribute significantly to our understanding of wind impacts on the system as well as on ways that the impacts of wind's variability and uncertainty can be addressed in a cost-effective manner.

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