Best Practices in Grid Integration of Variable Wind Power: Summary of Recent US Case Study Results and Mitigation Measures[1]

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***Abstract*— In only 6 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. As a result, numerous utility wind integration studies are being conducted in the US under a variety of industry structures. This paper will summarize results from a number of case studies conducted recently in the US, and outline a number of mitigation measures based on insights from the recent studies.**

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

I. Introduction

THE United States is experiencing an unprecedented period of wind power growth. The installed wind capacity grew from approximately 9,000 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. Conducting an integration study is a time consuming process, especially for an organization conducting one for the first time. These studies also serve to reduce the time required to conduct future studies, since the methods and results can provide guidance to new studies. The case studies summarized here address concerns about the impact of wind power's variability and uncertainty on power system reliability and costs.

Wind resources can be managed through proper plant interconnection, integration, transmission planning, and system and market operations. This paper will not address the physical interconnection issues, but rather will focus on the last three options. It is accordingly divided into three sections: 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]. These costs are for operational practices and policies that conform to the "status quo"; there was little attempt to find the "best" way to integrate wind. This finding will need to be reexamined as the results of higher-wind-penetration studies—in the range of 25% to 35% 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

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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 previously imposed through Open Access Transmission Tariffs under Federal Energy Regulatory Commission (FERC) Order No. 888 [3]. The FERC has recently decided to move towards cost based imbalance charges, as outlined in FERC Order 890 [4]. A variety of means, such as commercially available wind forecasting and others discussed in this paper, can be employed to reduce these costs.

Because wind is primarily an energy source, not a capacity source, no additional generation needs to be added to provide back-up 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. 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 integration impacts in the United States and in Europe over the past few years. This paper focuses on the United States; many of the European reports are summarized in Holttinen et al. [5] and Gross et al. [6]. The European results and insights are consistent with the U.S. studies examined here.

II. WIND PLANT INTEGRATION OPERATING IMPACTS

The upper Midwest region of the US has seen a large increase in wind power development in the past five years. Much of this development is taking place in the footprint of the Midwest Independent System Operator (MISO). Within MISO, the State of Minnesota has been particularly active, having recently passed a state Renewable Portfolio Standard (RPS) of 25% of electrical energy by 2025. The RPS was passed after completion of a study investigating the impact of increasing levels of wind penetration from 15% to 20% to 25% of electricity from wind by 2020. The study [7] is one of the most comprehensive performed to date in the US, and the question of reserve requirements and impacts on unit commitment were significant factors in the investigation, as were the roles of wind forecasting and market operation. This study will be reviewed and summarized here as an example of the most recent work from the US, and will be supplemented with additional results from recent work.

The primary objectives of the MN study were to evaluate the cost and reliability impacts associated with increasing levels of wind penetration up to 25% in the State of Minnesota, and to identify options for managing the impacts of that level of wind generation. The general approach in such a study is to carefully evaluate the physical impacts of wind on the grid, 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. These meteorological simulations need to employ physics-based weather models, use a robust input data set, and be of sufficient geographic resolution to accurately capture the topographical effects on wind variability. 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].

It is important to identify the type and amount of the different reserves to be provided in order to manage the variability and uncertainty associated with the wind generation. The need for additional reserves occurs across all time scales, from seconds (primary reserves) to minutes (secondary reserves) to tens of minutes (tertiary reserves) to hours and days. Production costs increase as the total operating reserve increases, as one would expect. However, it is important to note that the additional reserves are not fixed, but are a function of the amount of wind production at any particular time. Little additional reserve is required when the wind production is low. If reserves are being held for hourly variability, it is also important to note that not all of the reserve needs to be spinning. Changes in the later part of the hour can be covered by non-spinning reserves where available. The significance of this is that no charge is incurred unless they are used. It is important to understand the variable nature of the reserves required because of the reduced production cost compared to the case of fixed reserves. Indeed an important outcome of an integration study, and certainly of actual operating experience, is developing a good understanding of how to avoid over-planning system reserves and unnecessarily adding to the cost of integration.

The Minnesota system, which was the subject of the study, consists of the consolidation of four main balancing areas into a single balancing area for control performance purposes. This assumption is expected to be realized in practice with the start-up of the MISO Ancillary Services market in 2007. Simulations investigating 15%, 20%, and 25% wind energy penetration of the Minnesota balancing area retail load in 2020 were conducted. The 2020 system peak load is estimated at 20,000 MW, and the installed wind capacity is 5700 MW for the 25% wind energy case. Regardless of the power market structure, most studies divide the wind impacts into the time frames that correspond to grid operation. Fig. 1 illustrates these time scales. The reserve categories identified and modeled in the simulations included regulating reserve, contingency reserve, load following reserve, and operating reserve margin. 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.

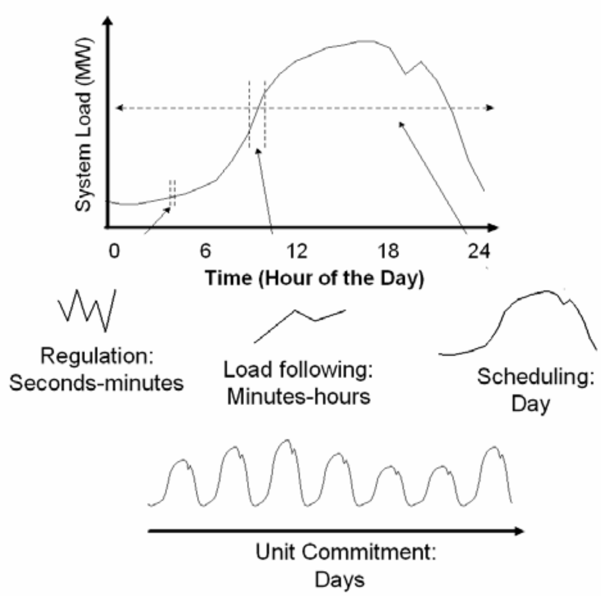

Fig. 1. Time scales for grid operations [1]

Regulating reserve provides compensation for system imbalances over very short periods of time (seconds to minutes). This service is provided from units with the necessary response rate operating on Automatic Generation Control (AGC). Based on conversations with operations personnel from MISO, the relationship shown in Fig. 2 was derived for the system without wind.

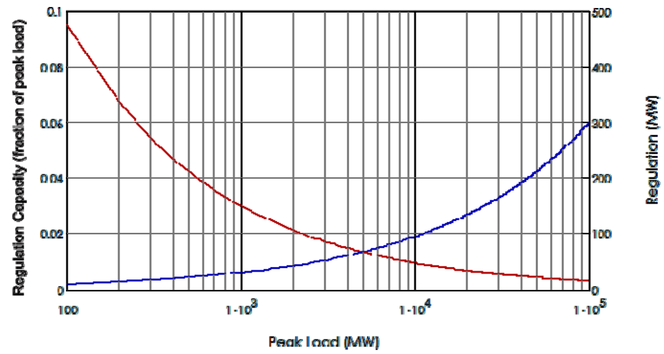

Fig. 2. Approximate Regulating Requirements for a Balancing Authority as a Function of Peak Demand [7]

Although the regulation capacity decreases as a percent of peak load, the actual MW required increases, but yields a number significantly less for the combined balancing areas than for the sum of the individual balancing areas, as shown in Table 1.

Balancing Authority	*Peak Load (MW)*	*Regulating Requirement (from chart)*	*Regulating Requirement (% of peak)*
GRE	3443	56 MW	1.617%
MP	2564	48 MW	1.874%
NSP	12091	104 MW	0.863%
OTP	2886	51 MW	1.766%
Sum of Regulating Capacity		**259 MW**	
Combined	20984	**137 MW**	**0.655%**

Table 1. Estimated Regulating Requirements for Individual and Aggregate MN Balancing Authorities [7]

Using Table 1 as a starting point, based on the NREL analysis [9] of the regulation time frame characteristic of 2 MW for a 100 turbine wind plant, the regulation requirement for the Minnesota balancing area is shown in Table 2.

Scenario	Regulation Capacity Requirement
Base	137 MW
15% Wind Generation	149 MW
20% Wind Generation	153 MW
25% Wind Generation	157 MW

Table 2. Estimated Regulation Requirement for MN Balancing Authority in 2020 [7]

The single largest contingency in the MAPP Generation Reserve Sharing Pool, of which the Minnesota balancing area is a part, is the loss of a 500 kV line to Manitoba with imports of 1500 MW. This remains the single largest contingency for the study period, so the Minnesota share of 660 MW for this contingency, 330 MW spinning and 330 MW non-spinning (quick-start), remained unchanged. Further consolidation into the Midwest Contingency Reserve Sharing Group in 2007 is expected to further reduce this obligation.

Within the hour, once the regulation service has been provided, additional flexibility is required to follow the slower trends in the net load shape from hour to hour. This flexibility is provided through the 5 minute market. Additional flexibility is required in the market as additional wind generation is installed. This additional flexibility was determined based on a statistical analysis of the 5 minute changes in the net load. The standard deviation of these changes is shown in Table 3.

Scenario	Standard Deviation of 5-minute changes
Base	50 MW
15% Wind Generation	55 MW
20% Wind Generation	57 MW
25% Wind Generation	62 MW

TABLE 3. SUMMARY OF FIVE MINUTE VARIABILITY [7]

Two standard deviations encompass over 95% of all variations, which was deemed sufficient to meet the CPS2 criterion. This requires that the difference between load and generation over a 10 minute period must be smaller than a specified limit for 90% or more of the 10 minute intervals during a month.

Due to the favorable impact of a large number of wind plants distributed over a significant geographical footprint, the major variability and uncertainty associated with the wind plant output is moved into time frames from one to several hours ahead. A persistence forecast is a good proxy for the forecasting method expected to be used for this time frame. Table 4 shows the next-hour standard deviation from a persistence forecast for the three wind generation scenarios.

Scenario	Standard Deviation of 1-hour Wind Generation Change
15% Wind Generation	155 MW
20% Wind Generation	204 MW
25% Wind Generation	269 MW

Table 4. Next Hour Deviation from Persistence Forecast by Wind Generation Scenario [7]

In the study, additional hourly reserves of twice the standard deviation, referred to as operating reserve margin, were conservatively decided upon to accommodate the unpredicted hourly changes in the wind generation.

Based upon the above considerations, a table of Total Operating Reserves (Table 5) can be constructed. This table summarizes the additional reserves carried due to the variability and uncertainty of the wind plant output as described above, given in MW and in % of balancing area peak load.

Reserve Category	Base		15% Wind		20% Wind		25% Wind	
	MW	%	MW	%	MW	%	MW	%
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-Spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load Following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating Reserve Margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total Operating Reserves	**1049**	**5.00%**	**1229**	**5.86%**	**1335**	**6.36%**	**1479**	**7.05%**

Table 5. Estimated Operating Reserve Requirement for MN Balancing Authority with 2020 Load [7]

A simulation of the market behavior both with and without a day-ahead wind plant forecast was conducted in the Minnesota study. Ignoring wind plant output in the day-ahead unit commitment introduces inefficiencies into the market operation. Without a wind forecast, units are committed to supply a greater amount of load than actually exists. The production costs are less for the case with a wind forecast than the case without. Market participants will respond to incorrect market signals if the wind forecast is ignored, and generation will be offered into the market and committed to serve load which would already be served by the wind. 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.

Three years of high resolution wind and load data were used in the study. The results in Fig. 3 show that the cost of wind integration ranged from a low of $2.11/MWh of wind generation for 15% wind penetration in one year to a high of $4.41/MWh of wind generation for 25% wind penetration in another year, compared to the same energy delivered in firm, flat blocks on a daily basis. These are total costs and include both the cost of additional reserves, and cost of variability and day-ahead forecast error associated with the wind generation.

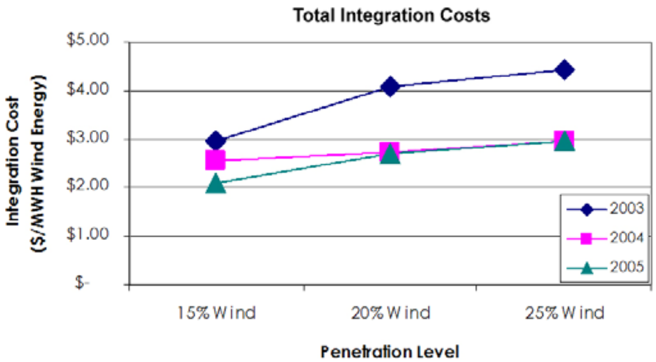

Fig. 3. Total integration costs for three penetration levels and pattern years [7]

The cost of the additional reserves attributable to wind generation is included in the wind integration cost. Special hourly runs were made to isolate this cost, which was found to be about \$.11/MWh of wind energy at the 20% penetration level. The remainder of the cost is related to how the variability and uncertainty of the wind generation affects the unit commitment and market operation.

The geographical dispersion of the wind plant was found to be an important factor in reducing the variability of the total wind plant output. The number of hours spent near full output or near zero output was significantly reduced compared to multiple smaller wind plants looked at in isolation. Variability inside the hour was not a significant cost element in the study, and the reduced inter-hour variability caused a reduction in the burden placed on unit commitment and dispatch. A critical assumption in this regard was that transmission was expanded in accord with the MISO Regional Study Group assumptions, which included transmission expansion plans within Minnesota and to the rest of MISO, allowing for robust market operation.

In the study, the Minnesota balancing authority was assigned responsibility for all the reserves and intra-hour resources for balancing. At the hourly level, the day-ahead markets and in-the-day re-dispatch at the hourly level were administered by MISO for the entire footprint. Since the real-time market actually operates on five-minute increments, further efficiencies could be obtained if it were assumed that out-of-state resources were available to balance within the hour.

In summary, the study showed that the aggregation of load, wind, and generating resources over a wide area, combined with structures that seek to optimize for the whole rather than for individual pieces, have tangible and significant benefits for wind integration, and that a robust transmission system is key to achieving these benefits.

In other recent work carried out in the US, both the greater variability that wind imposes on the system, and the increase in the uncertainty introduced into the day-ahead unit-commitment process, have been found to have similar impacts on the integration cost [10], [11], [12], [13], [14]. 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 6 shows the integration cost results from some of the major studies recently undertaken in the United States.

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 (Fig. 4). In some cases, simplified methods are used to approximate the rigorous reliability analysis [15].

III. 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 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 is more appropriate for wind than a penalty-based tariff. This provides 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

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commit-ment 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
Dec 06	MN/MNPUC	30	na	na	na	na	4.41
July 04	CA RPS Multi-year Analysis	4	0.45	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

Table 6. Wind integration Costs in the US [UWIG]

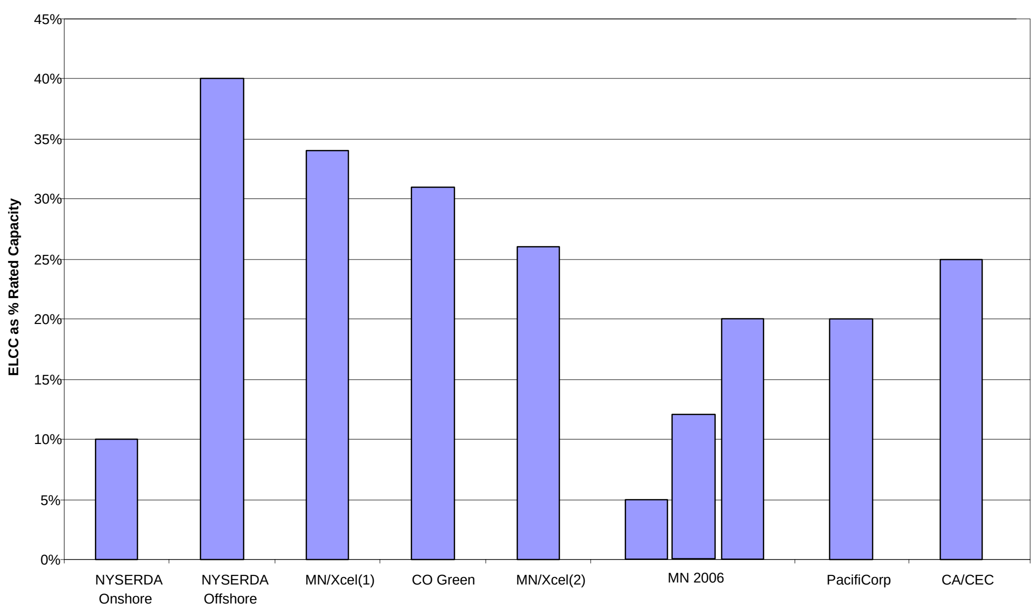

Fig. 4. Wind Plant Capacity Value from Selected Studies [UWIG]

imbalance to all entities, not just wind. FERC recently addressed this issue in Order 890, which widens the bandwidth for renewable intermittent/variable generation and moves most wind imbalance to a cost-based payment.

Market areas 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 [11]. 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 and to examine whether there is physical interconnected capability that could be tapped to help with these events if proper market mechanisms are available.

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 ACE (Area Control Error) 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. FERC Order 890 now requires such a product to be offered, resembling a firm transmission product but with some level of potential curtailment that can be capped at an agreed-upon level by the buyer and seller. The recent FERC Order 890 also addresses the calculation of ATC in order to provide for greater consistency in ATC calculation. 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.

IV. 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 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 35% and have found that the primary considerations are economic, not physical. The question is one of dealing with the cost of 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 35% in response to state-level RPS requirements. Such studies are being conducted in California, Colorado, Wisconsin, the Pacific Northwest, and the complete 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:

- **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. Conducting this evaluation necessarily depends upon an accurate prediction of wind power plant output and associated variability, that is time synchronized with the system load profile.
- **Aggregation of wind plant output over large geographical regions:** Due to the lack of correlation between wind plant output over broad geographical regions (100's of km), a substantial smoothing effect can be achieved by aggregating the output of wind plants in a variety of locations. This can help reduce the variability within the hour, as well as inter-hour, and thereby reduce the burden on the reserve requirements. [7]
- **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 [20] Furthermore, due to the significant influence of wind forecasting on this cost, defining and employing appropriate methods for creating wind power forecasts and their inclusion into integration cost studies is quite important.
- **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]
- **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 makes the unused capacity available for other transactions when the line is lightly loaded. [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 Federal Energy Policy Act of 2005 (EPACT 2005) is moving forward with identifying new transmission corridors that could help with this problem. [21] Innovative policies are also being considered at the state-level to facilitate building of transmission to wind resource areas, in some cases in advance of commitments to build the wind generation.

- **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 [22]
- **Adopting market rules and tariff provisions that are more appropriate to weather-driven resources:** For example, imbalance penalties that are meant to incentivize the behavior of fossil generators cannot be used to affect the behavior of a wind-driven resource, and have been eliminated. Weather-driven resources should pay the costs they cause, rather than penalties for behavior they cannot affect [22]
- **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.

V. 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 which 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 nearly 50,000 MW of wind capacity, which serves as a valuable knowledge base for the United States, with 11,600 MW of capacity. Based on this experience, the following conclusions can be drawn:

- **Wind Plant Integration Operational Impacts:** World-wide 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. Recent changes include the elimination of imbalance penalties dealing with the differences between scheduled and actual production, and a flexible-firm transmission product to enable greater use of existing transmission system capacity which 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 valuable insights will be obtained 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, and on ways that the impacts of wind's variability and uncertainty can be addressed in a cost-effective manner.

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