Factors Relevant to Incorporating Wind Power Plants into the Generating Mix in Restructured Electricity Markets

*By Michael R. Milligan**

Introduction

In many places throughout the world there is increasing interest in developing power plants that are fueled by the wind. Wind power plants are a clean source of electricity. However, many electric generating companies are reluctant to install significant wind capacity because of the intermittent nature of the resource. Wind power plants cannot be controlled in the same way as their conventional cousins, and are subject to the availability of the wind itself. From one year to the next, it is also likely that the yield from a wind power plant will vary. Both of these issues can be characterized as different aspects of risk, which is becoming an important topic as the electricity industry moves toward a greater degree of competition under restructuring.

To reduce the risk of depending too heavily on one specific type of generation or fuel, resource-planning techniques have incorporated methods of portfolio diversification theory. Financial option theory is also used to evaluate the relative costs of building a power plant now or building it later. Another strategy is hedging, which can consist of forward trading or contracts for differences. Applying these theories and practices to resource planning helps companies assess and reduce risks in the emerging competitive environment.

In the regulatory environment, risk is shared by the consumers and the power company, although some would argue that most risk is borne by the consumer while the monopoly power company enjoys a virtually guaranteed rate of return set by the regulator. But as electricity markets become more open, power companies are attempting to recognize and quantify various risks that they had previously been able to ignore. Some of these include the risk that a new unit won't be completed when it is needed, the risk of fuel cost escalation, or future regulations covering various emission levels. Intermittent power plants, such as wind plants, enter risk discussions in several ways. There is the obvious risk that the wind power plant may not produce power when it is needed, but that is balanced against the risk undertaken by building power plants for which lifetime-fuel costs cannot be accurately determined at the time of plant construction. Although the fuel for a wind plant is inexpensive and in plentiful supply, the timing of its availability is not always known in advance, and is subject to variation. Other risks faced by power producers include the risk of future emissions abatement requirements and the resulting effect of the cost of conventional power generation. Power companies facing restructuring are familiarizing themselves with the principles needed to analyze the risks and benefits associated with wind power plants. As we move forward, risk-based performance measures of power systems, markets, and generators will become more prevalent.

This paper examines some of the factors related to the operation of, and planning for, wind power plants. In spite of the move towards restructuring and new ways of doing business, utilities that are evaluating wind power plants are asking questions about the intermittency of wind and the implications of this intermittency on power system operation. To deal effectively with intermittency, accurate wind forecasts can prove helpful, both in regulated and in unregulated markets. Another important consideration involves the measurement of available capacity to determine whether electric capacity is sufficient to cover demand. This leads us into the area of reliability assessment, and to reliability-based measures of capacity credit.

The power generation industry is assumed to include many types of firms, ranging from small firms that own one or two generating resources, to behemoth firms with generation ownership up to 30,000 megawatts (MW) or more. In this paper the term "utility" means power generator (also known as generating company or GENCO), as we straddle environments that are still regulated and those that have restructured. It is also assumed that at least some of these companies will hold both wind-generating capability and other conventional power generators, and that restructuring is a work in progress. The electricity industry has not been down this road before, and predictions about how a specific market will perform can only be answered with experience. As one of the earliest examples of restructuring, the United Kingdom power system has recently made some very significant changes in many aspects of the operating procedure of the electricity supply industry. Current events in the California electricity market demonstrate that generating supply adequacy, reliability, and capacity measurements, are still very important. Further discussion in this paper concerning the electricity market is made under the assumption that the restructuring dust worldwide has not yet settled. There are many underlying technical issues that must be addressed by the market, and the first and even subsequent versions of the market rules may not address all of these issues.

The results presented in this paper are from various projects undertaken at the U.S. National Renewable Energy Laboratory (NREL), involving electricity production simulations using actual wind-speed data, generator data, and electric load data. Data were also used from several different utilities or regions and many wind sites. The hourly data used for wind power are based on actual wind data and are applied to various wind-turbine power curves, all of which represent actual wind turbines, to calculate the hourly power output of several hypothetical wind power plants. The electricity production simulation and reliability programs used for this work are Elfin (a load duration curve model produced by Environmental Defense) and P+ (an hourly chronological model produced by the P Plus Corporation). In the wake of restructuring, both of these models have been enhanced to allow for the new electricity markets, but the primary least-cost dispatch algorithms are still at the heart of the models. Results from an experimental chronological reliability model developed at NREL are also included in this work. Although some of the focus and emphasis changes, competitive pres-

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sure will induce firms to assess the best (least expensive) way to produce electricity, subject to profit maximization. To maintain the reliability of the electricity supply, either some form of reliability-based pricing or regulation may become necessary.

Some of the factors relevant to incorporating wind plants into the generation mix can be framed by these questions: Does a wind power plant offer any value to a generation company that owns a variety of generating resources? Can wind energy systems reduce the need for conventional generation in the industry supply portfolio? If so, how much generation can be displaced, and how can it be measured? Does the intermittency of wind power plants present any significant problems for the operation of electric power systems? Can any of these problems, or problems of lesser significance, be mitigated, and if so, how? Will it be possible for wind plant owners/operators to participate in the newly emerging electricity markets, such as day-ahead markets, in the new market structure?

The Value of Wind Power Plants

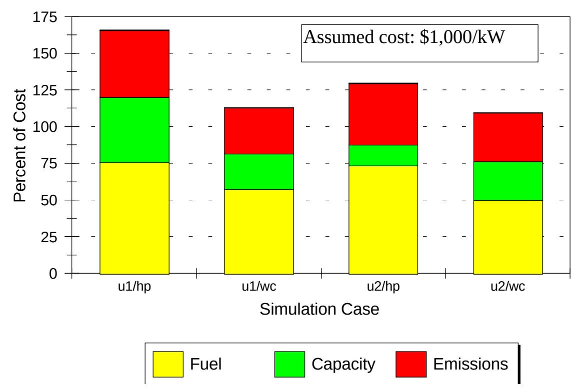
It is widely recognized that wind power plants can provide energy value to the grid. This value is a result of the reduction in electricity generated from conventional power plants, made possible by the wind plant. The value of offset fuel consumption and emissions reduction can be calculated by an electricity production simulation model. In many cases wind power plants can offset the need for conventional power plants. The variable and marginal costs of wind generation are typically less than most, if not all, other power plants because there is no fuel cost, and operation and maintenance costs are very low. In regulated electricity markets, this means that each wind-generated kilowatt-hour (kWh) would be utilized whenever available, making it possible for the utility to ramp back on other load-following power plants. As we move toward a restructured industry, generating companies with diverse generating portfolios will still attempt to produce electricity, subject to various bidding strategies, at lowest possible cost and highest possible profit. Therefore, a generating company that owns a portfolio of generators that includes wind power plants will attempt to maximize the efficient use of the wind plants to reduce fuel costs associated with conventional power generation.

The value that wind plants contribute to generating companies depends heavily on the GENCO's specific combination of generators, and the influences of the chronological wind pattern and its relationship to the expected load. A wind site that is attractive to one utility may not be as attractive to another. Milligan and Miller experimented with various combinations of wind sites and utility data and found significant variations in the benefit of otherwise identical wind power plants to different utilities. In a study by Milligan, two large utilities were modeled. The model paired each utility with each wind site, one at a time. The benefit provided by the wind power plant includes three parts: (1) energy, which represents the reduction in conventional fuel cost resulting from adding a wind power plant; (2) capacity, defined in this case by the shortage method adopted by the California Energy Commission (CEC) prior to restructuring in California; and (3) emissions value, which was also valued on a per/ton basis by the CEC prior to restructuring. The full social value of reduced emission levels may not find its way into the market, but is a well-known market externality. The energy, capacity, and emission values were calculated by initially running the model without any wind generation. After the results for this no-wind case were collected, the values were recalculated to include a 125 MW wind power plant. The difference between these two cases gives us the value provided by the wind power plant.

Figure 1 illustrates the results for the two utilities, U1 and U2 (the utilities are not identified because of prior agreement). The wind sites utilized in this study include a site from a West Coast mountain pass (WC) and a site from the High Plains (HP). The vertical axis of the graph represents the benefit as a percent of cost, which is $1,000/kW. It is clear from the diagram that (a) a given wind site will contribute a different level of value, depending on the utility, and (b) the value of wind power to a utility will vary as a function of the chronological variation of the wind power plant.

Figure 1

Value vs. Cost for Several Wind Site and Utility Combinations



Milligan also shows the results of several electricity production simulations using a chronological model. Using various combinations of utilities and wind regimes, this work shows the reduction in generation from those units on the margin during periods of significant wind generation when the chronological unit-commitment and economic dispatch is optimized to include the wind plant. For one of the large utilities that was studied, the total number of start-stop cycles from conventional power plants was reduced by about 700 cycles/year.

Forecasting, Capacity and Risk

There are several ways to look at the effective capacity of wind power plants. In regulated markets the term "capacity credit" is often used to describe the level of conventional capacity that a wind plant could replace. This section assumes that uses of the term "capacity credit" may be more general in the newly restructured markets. It begins by discussing some general characteristics of various pool bidding processes and the unique issues raised by wind power plants in these arrangements. The discussion will look at short-term markets and the role wind forecasting can play in those markets, followed by an examination of measures of capacity credit that are based on reliability estimates. These estimates have been used in some regulated environments. Whether these will be appropriate in the new electricity markets may still be open to some question.

Bidding Wind Power into the Supply Pool

Because electricity has a higher value during periods of system peak demand, generating companies will have a higher economic incentive to secure a bid into the pool during these times, as compared to periods of relatively low system demand. As the restructuring landscape continues to evolve, differences in many aspects of the wholesale electricity market will surface as they did in California in the United States, and in the United Kingdom. However, an emerging trend is for some mechanism by which buyers and sellers strike agreements on price and quantity during a period prior to the actual transaction. The elapsed time between the agreement and the actual exchange of power may range from hours to days in these short-term markets. This discussion only describes short-term operational transactions, ignoring any longer-term transactions so that we can focus on the operational market.

Wind power plant owners must participate in such bidding arrangements to sell power unless bilateral contracts or market bundling become significant. Although the short-term markets may include some provision to account for spinning reserves to cover unforeseen generator malfunction or higher than anticipated customer load, it is advantageous to the wind plant owner to ensure that the capacity or energy bid into the market can be supplied at the specified time of delivery. However, there are various mechanisms that can be used when contracted power is not delivered as specified. An example of one mechanism is the Balancing and Settlement Code (BSC) in the United Kingdom, in which market participants must pay for any imbalances during a settlement period that occurs after the time of the specified transaction. Therefore the wind plant operator, as do all power plant operators, has an economic incentive to bid quantities into the market that can be reasonably supplied.

For the wind plant operator there is an additional complication. The intermittent nature of the wind makes it impossible to control the power plant the same way a conventional unit is controlled. Significant social costs are imposed during outages, which is why all electrical systems maintain a spinning reserve. However, scheduling more generation than is needed also results in unnecessary costs. The incidence of these costs can vary widely, and can include any combination of the power generators, distribution companies, or ultimate consumers. The total generation supplied should equal total demand (allowing for reserves, ancillary services, etc.) to minimize costs that are induced by either an oversupply or undersupply of electricity. Therefore, the stochastic nature of the fuel source makes it vital for the wind plant operator to obtain an accurate forecast of the wind speed for the power delivery period.

An accurate forecast would have value in bilateral contracting, or any other arrangement under which the wind power plant operator/owner sells power on a scheduled basis. The value of an accurate wind forecast in a pool arrangement will depend on many factors; among them is the generation portfolio that is controlled by the GENCO. If a quick-response unit is part of that portfolio, that unit can be brought online quickly during unexpected lulls in the wind. Conversely, if there is an unexpected period of wind, it is possible that a combustion turbine or other similar unit can be ramped down to avoid the use of a relatively expensive fuel.

Milligan, Miller, and Chapman modeled two large utilities in two regulated markets and showed significant economic benefits of accurate wind forecasts. Their approach was to calculate the optimal unit commitment schedule under various assumptions about wind timing and availability. To introduce forecast error into the model, they modified the wind power availability after fixing the commitment schedule to a specific wind forecast. This allowed them to calculate the difference in power production cost that would result from wind forecasts from various degrees of accuracy ranging from 0% — 100%. They found that the economic benefits of an accurate forecast were substantial because errors in unit commitment and economic dispatch can be reduced or avoided. It is also likely that accurate wind forecasting will help reduce or eliminate any operating penalties that might otherwise occur because of the intermittent nature of the wind resource.

The National Renewable Energy Laboratory is currently working with the Electric Power Research Institute on a wind energy forecasting development and testing program and is conducting independent research on wind forecasting techniques. Accurate wind forecasting may be one of the most important issues facing wind power plant operators in restructured electricity markets. As market-based electricity supply pools continue to develop around the world, wind plant operators must be able to participate in the various bidding arrangements. In the very short-term power markets, it remains to be seen whether separate capacity payments will be made, or whether energy will simply be more highly valued during peak periods than in non-peak periods. However, the penalty for over- or under-scheduling resources during the system peak is higher than during other periods. The most effective tool for the wind plant operator may be an accurate wind forecast for the period that is covered by the bidding process.

Reliability-based Measures of Capacity Credit

As utilities develop more risk-evaluation strategies, a central element will continue to be overall system reliability. This paper ignores the reliability aspects of the transmission and distribution grids, as the number and complexity of transactions on these grids continues to increase. However, this aspect of reliability will be critical in the future. For example, a recent international panel of electric-system reliability experts agreed that: (1) electrical reliability in the United States is very high today, particularly as viewed in the context of generation reliability; (2) the transactions in the wholesale market that will arise from the restructuring of the industry will be far more complex than they were in the past; and (3) system reliability will likely worsen, but will in any case continue to be an important issue in a restructured market. This section will focus on the reliability of the generating system. Recent experiences in parts of the United States indicate that concerns over the adequacy of the generation supply appear to be warranted. Given the stochas-

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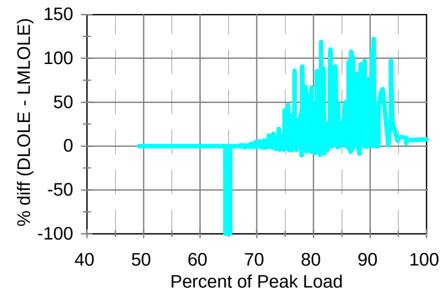
tic component of electricity demand and a corresponding stochastic component of the generation supply, the grid operator is still faced with the problem of balancing loads and resources. As regional coordinating councils or power pools evaluate the electricity supply in future peak periods, risk assessment will continue to be important. Large GENCOs still perform reliability studies, and measures such as loss of load probability (LOLP) are still used to assess system adequacy. Until the new BSC recently went into effect in the United Kingdom, LOLP was used to determine capacity prices, although that caused significant volatility in those prices.

There are several ways in which one can evaluate the reliability contribution of a single power plant to the generating system. One way involves calculating the reliability measure of choice (LOLP or expected energy not served, [ENS], for example) and comparing the results with and without the generator of interest. Another approach is closely related, but instead of using LOLP or ENS, the reliability measure is converted to a megawatt quantity by increasing the peak load until the reliability matches the base case (excluding the generator of interest). This quantity, called the effective load carrying capability (ELCC), is well known and has been widely used for many years. ELCC has traditionally been called a measure of capacity credit. To evaluate competing power plant options, one can calculate the ELCC of each plant to determine the effective capacity contributed by each one. Another related approach is to compare an intermittent power plant, such as wind, to its closest competitor; often a gas plant. The evaluation strategy works like this. For a given size gas plant, calculate the system reliability for the generating system, including the gas plant. Record the system reliability attained by the calculations. Then remove the gas plant, substituting increasing penetrations of wind capacity until the reliability measure equals the system reliability in the gas plant case. Once this equality has been achieved, the rated capacity in MW of the wind plant is reliability-equivalent to the gas plant.

ELCC can be calculated for a wind power plant, using the same basic technique as for conventional power generators. The advantage to using a measure such as ELCC is because it takes the relative load level and timing of wind power delivery into account. For example, a wind power plant that generates most of its output during off-peak periods would achieve a lower ELCC value than a wind plant that generates most of its energy during peak periods. ELCC also makes it possible to compare two or more generation options that deliver the same level of reliability to the grid. Although these calculations can be done with a load-duration model, the results are more accurate with actual hourly chronological wind power output and hourly chronological load data.

However, many chronological production simulation and reliability models may not accurately capture the probability that a wind plant may not deliver its statistically expected output and also model the time-variability of a wind plant. Figure 2 shows a comparison of the conventional reliability calculation of loss of lead expectation (LOLE) as calculated by a commercial model, and calculated by an experimental chronological reliability model developed at NREL. The graph shows the difference as a function of the load level for the electrical supply in Minnesota, along with a large composite wind site. The graph shows that there is a significant difference between what is normally calculated

Figure 2
Comparison of Reliability Measures of a Wind Power Plant



when wind power is treated as a load-modifier (LMLOLE) in the modeling process, as compared to a direct assessment based on the chronology of the wind power output (DLOLE). As the need for wind power plant reliability assessment increases, it will be important to adjust the fundamental reliability algorithm so that more accuracy can be achieved.

Will ELCC still be relevant in the new markets? There will continue to be a need to measure capacity contributions and risk. If ELCC is not the right measure, another may take its place for large-scale evaluations of generation adequacy (pools, control areas, etc.) Investors and GENCOs also need information that helps compare different power generation options, risks, and estimated rates-of-return for alternative power plants. These rates-of-return may be based, at least in part, on capacity payments, depending on the structure of contracting in the electricity market. ELCC provides important information about how the plant operates in the context of the market or GENCO assets and has a built-in risk component, so it may continue to be useful as risk analysis becomes more important in the new markets. ELCC or variations on ELCC could also play a role in determining capacity payments or risk-based assessments of whether a wind plant operator is likely to meet a bid into a day-ahead or hours-ahead market. Because of the evolutionary nature of restructuring, the notion of capacity credit may be somewhat transitional in nature, and whether ELCC continues its useful life in the long term may be open to some question.

Year-To-Year Variability and Extensions to Generalized Risk Assessment

Because wind speed can vary significantly from year to year and from hour to hour, capacity credit estimates that are based on a single year (or less) of data and modeled without taking this variation into account may not be credible. This section examines modeling techniques that can help assess this variation, and suggests that these methods can be extended for generalized risk assessment.

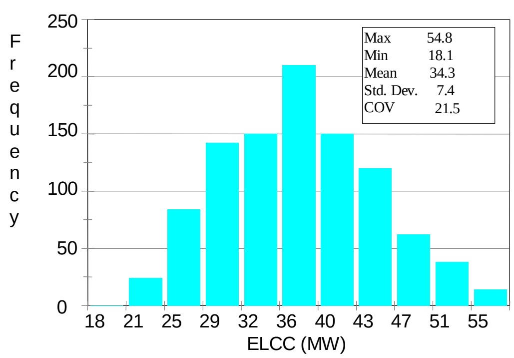
Many production-cost and reliability models have a Monte Carlo option that allows sampling from the probability distributions of generator availability. This approach is used to obtain a better estimate of the range of possible outcomes than can be provided by the usual convolution approach.

Another advantage of the Monte Carlo method is that it provides estimates of various probability distributions, such as system reliability and system costs. The P+ model also has a branching option that combines the more efficient convolution approach with the more precise Monte Carlo method. The branching technique performs the usual convolution on all but one generator. This generator's state will be sampled repeatedly via Monte Carlo, holding all other generator values to the expected values from the convolution. This allows the analyst to focus on the effects of a particular generator, without paying the full price of heavy execution time that can be exacted by full Monte Carlo simulations. An excellent discussion of this technique in the context of chronological production cost models can be found in Marnay and Strauss.

This approach appears to be ideal for modeling wind power plants. Unfortunately, the Monte Carlo simulation procedures generally sample from a very simple probability distribution that is not appropriate for wind power plants. This leads us to consider separating the probabilistic sampling from the production-cost model. The method involves repeated creation of synthetic wind-speed data, that can easily be used to calculate hourly wind power output. One can obtain a sequence of such data sets, and then run a series of production model simulations, capturing the results of these runs and summarizing in a convenient form. The Monte Carlo process is used to create the synthetic wind series, and the production-cost or reliability model can be applied to each. This is sometimes called "Sequential Monte Carlo" to differentiate it from the Monte Carlo logic that is often found in the models themselves. Milligan illustrates such a Monte Carlo method, and it is similar to a technique proposed by Billinton and Chen. Milligan applies this approach to a 13-year data set, and compares the capacity credit results obtained with the external Monte Carlo method with results using the actual wind-speed data. The findings indicate that this modeling procedure did a very good job of estimating the variability in capacity credit, but somewhat underestimated the variation in energy production. Milligan and Graham extend the basic framework, using the Elfin and P+ models, and introduce a reduction technique to help minimize the significant model run-time that is required for the full simulation set.

The Milligan and Graham study examined the influence of inter-annual variations in wind on ELCC, production cost, and the scheduling of various conventional generators. Their approach was to generate 1000 synthetic hourly time-series of wind speed with properties similar to actual hourly wind speed. For each of the synthetic series, they ran a production simulation model and calculated ELCC. Although this approach is very time-consuming, it helps answer basic questions about the likelihood of significant variations in the timing and availability of wind power. Figure 3 shows a frequency distribution of 1000 model runs based on a wind plant with a rated capacity of 100 MW. From the graph we can determine that 500 times out of 1000 we would expect the ELCC of this particular wind plant to fall between 32% and 40% of rated capacity.

Figure 3
Estimated Variations in Effective Load Carrying Capability of Wind Power Plant



The same technique can be applied to various other items of interest. For example, a GENCO can run such a model to determine the likelihood of committing a conventional unit given a particular bidding strategy and expected wind forecast error. Milligan and Graham successfully applied this method to examine various generating schedules and costs that would vary as a function of year-to-year changes in wind generation. One of the by-products of this type of modeling is the probability distribution of the parameter of interest.

Impacts of Geographic Dispersion

Several studies have examined the issue of geographically dispersed wind sites and the potential smoothing benefit on aggregate wind power output. The principle behind this benefit is that lulls in the wind tend to be more pronounced locally than over a wide geographic area. Building wind capacity at different locations may help reduce the problems caused by the intermittency of the wind resource, although the benefit of this geographic spread may be limited by various control area constraints. Wind developers in competitive electricity markets will likely examine these effects closely and use broader geographic areas to reduce the risks of not meeting committed capacity targets and highly varying wind output. Kahn's analysis is based on data collected in California. Grubb analyzes the effects of smoothing from wind generating units in Britain. Milligan and Artig examined a reliability optimization for the state of Minnesota but did not address economic benefits. Ernst provides an analysis of short-term, high-resolution wind data in Germany. And Milligan and Factor examined a geographical optimization using two optimization targets: reliability and economic benefit. All of these studies find that the geographic spread of wind generators provides a smoothing benefit when wind output is aggregated. Although it is measured differently in these studies, the results appear to be robust across time-scales ranging from minutes to hours.

From here, the analysis can get a bit complicated. The benefits of geographically dispersed utility-scale wind power plants can be analyzed to maximize a number of optimization targets. A joint project undertaken by NREL and the Minnesota Department of Public Service set out with a goal to find the combination and sizes of wind power plants that would maximize system reliability. Eight hundred twenty-five MW of rated wind capacity was selected as the total level of installed capacity, corresponding to the capacity level that was negotiated between the state of Minnesota and Northern States Power as part of the Prairie Island nuclear waste storage agreement. Milligan and Artig applied a fuzzy logic

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search technique to examine the most promising locations and sizes, evaluating the composite generating system reliability as a function of the geographic dispersion of wind capacity for the state of Minnesota. They found that the highest level of generating system reliability was possible by installing the wind capacity at a combination of sites, and that hourly variation in wind power output can be substantially reduced when a combination of sites is used.

Milligan and Factor did a similar analysis for the state of Iowa, confirming the results from the Minnesota study. They applied both a dynamic fuzzy search technique and a genetic algorithm to the optimization process. However, in this case, there were twelve wind sites with a total installed capacity target of 1600 MW. Their model was run with projected hourly load data for the year 2015, along with detailed information about all power generators and significant power exchanges in the wholesale power market in Iowa. To reduce computer run-time to a manageable level, they considered 50 MW as the smallest increment of wind capacity development that could be built at a single site. Even with this restriction, there are approximately 5 x 10^9 possible ways to build 1600 MW among twelve sites. Given the extremely large number of potential solutions, their technique provides several alternative solution sets, each of which represents either the best or close-to-the-best combination of sites. In this study, they redefined "best" to be that combination of sites that would minimize the cost of running the conventional generating units. Additional model runs identified the combination and location of sites that would maximize electric system reliability, and these are described in their paper.

Figure 4
Top 12 Site Combinations Based on Economic Benefit for Iowa

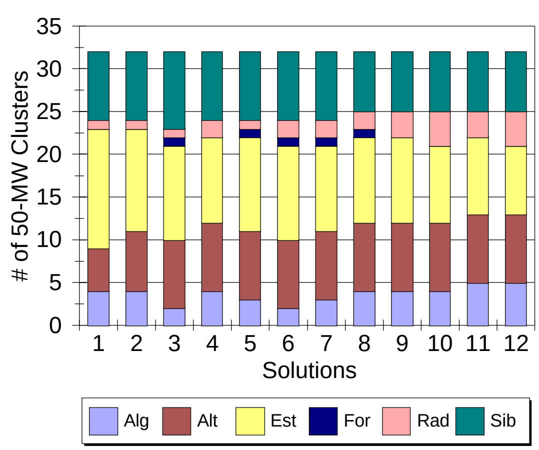

Figure 4 illustrates the basic results. Each bar represents a solution that identifies a particular combination of wind plant locations and sizes. For example, the bar on the far left side shows a recommendation of 4 50-MW clusters at Algona ("Alg"), 5 clusters at Alta ("Alt"), 13 clusters at Estherville ("Est"), and so forth. Bar two shows a slightly different combination of sites than bar one: more wind capacity at Alta is traded against less capacity at Estherville. Even though the number of clusters at Alta and Estherville differ significantly between the two solutions, the economic benefit between these two solutions is extremely small.

Not all sites were chosen for potential development. This suggests that although geographic dispersion can provide benefits, it is not a foregone conclusion that sites not in proximity of each other will necessarily provide economic or reliability benefits to the grid.

Milligan and Factor did significant testing of alternative site combinations that they considered close to the choices recommended by their model. They found a very large number of additional site combinations that were nearly as good (by their metric) as the site combinations that appear in Figure 4. They believe that these multiple solutions provide significant latitude to take other constraints into account that the modeling process does not explicitly recognize. Some of these constraints include transmission constraints, land-use constraints, or other operational issues such as local voltage or volt ampere reactive (VAR) support. This modeling process allows them to investigate the merit of building a small amount of capacity at one of the sites that was not chosen by the optimization process, given that they make small changes in the capacity recommendations at the remaining 11 sites. This provides decision-makers with extraordinary latitude in selecting the locations and sizing of geographically dispersed wind power plants.

Other Issues

On the basis of day-to-day operations, various power pools and control areas have specific ways of assessing the operational capacity credit of all generators in the region. This capacity credit is assessed in part to determine whether available capacity exists in the region during the specified time period. Wind power plants can provide operational capacity credit, although typically at some fraction of rated capacity. As various operating regions and pools mature under restructured electricity markets, the pool accreditation rules may be re-evaluated. It will be important for these rules to treat all resources in an unbiased way and yet recognize the difficulties imposed by intermittent power plants.

In the analysis of Iowa, Milligan and Factor used the capacity credit procedure from the Mid-Continent Area Power Pool (MAPP), one of only two pools that specifically addresses wind power plants. Applying this method to the top 12 fuzzy solutions, the annual average capacity credit was 47% of the rated capacity of the composite wind plant, with significant monthly variation. The MAPP method is based on finding the median output of the power plant during a four-hour window surrounding the monthly system peak, as contrasted with LOLP-based methods that consider a broader time period, weighting the more critical peak hours according to the potential loss of service.

Wind power plants must be located at sites that have a good wind resource. Unfortunately, this may be at a location that is far away from the load center and/or from a transmission interconnection point. There can be an additional complication even if transmission is nearby, but the line is nearly fully loaded during times of peak wind plant output. Because wind power plants typically operate at annual capacity factors in the range of 20% — 40%, the high fixed cost of transmission line construction is spread over fewer kWh than for most conventional power plants. As wind operators bid into an electricity supply pool, transmission capacity must also be available at the time the wind power is available, and this introduces additional complications into the life of the wind plant operator. However, for a wind plant that may reach its peak output for a small number of hours during the year, limited curtailment of wind power output might be preferable to expensive transmission upgrades that are needed for a limited time. The formation and revision of transmission access rules will play an important part in wind plant development in the new millennium. Rules should not impose implicit or explicit barriers to entry, and must fairly allocate costs, even across multiple operating regions. Penalty-based rules in ancillary services markets are less desirable than make-up rules, allowing the generator to replace capacity or standby power that may have been incorrectly supplied. However, penalties that result from operating practices different than instructed by the system operator would be acceptable. The National Wind Coordinating Committee in the United States has analyzed these and other additional transmission issues. The results are available on the internet at http://www.nationalwind.org/pubs.

There are still several unanswered questions regarding additional smoothing effects that were not considered by these hourly analyses. How much smoothing occurs within a wind power plant on a second to second basis? What are the impacts of short-term fluctuations on frequency regulation and spinning reserve requirements? Ernst began to analyze these questions by looking at some high-resolution data from the German 250 MW Wind Turbine Measurement Program. He calculated the smoothing impact of a small number of turbines on regulation, load following, and reserves. He found that a large number of turbines spread over relatively large distances may cause a significant decrease in the relative ancillary service requirements assigned to the wind plant. Ernst also found that there is a clear diversity benefit during short time periods (on the scale of minutes) that arises from the spacing of turbines at the site. Analysis of the regulation impact of the wind power plant can also be influenced by the spatial diversity of the turbines. NREL is currently collecting one-second data from a wind plant in the Midwest, and will conduct a detailed analysis of the power fluctuations and their impact on ancillary services. Another project underway at NREL is to adapt the experimental chronological reliability model so that reliability-based calculations can be used as a basis for allocating the spinning reserve burden to all power plants according to their capacity and frequency of variability.

The smoothing effects from large numbers of wind turbines and from geographically disperse sites appear to be significant. However, it is not yet clear how robust this smoothing effect will be to different sites around the world. As power plant owners and operators examine the question of how to diversify their holdings of different types of power plants to mitigate risk, it seems clear that wind plant site diversification plays an important role in this type of decision analysis. Site diversification reduces risks of sudden drops in wind power and spreads the risk of forecast errors. Smoother wind plant output appears to reduce the burden on regulation and other operational factors.

It is also important to analyze the impact of a wind power plant on spinning reserves and ancillary services in the proper context. For example, in a typical utility control area the level of required spinning reserve is assessed on a system-wide basis, and normally includes consideration of the largest hazard. At relatively low penetration levels, the variability of the wind plant would likely be significantly lower than the largest single generating unit in the control area. Utilities deal with uncontrollable load on a routine basis, and in fact are used to forecasting load based on weather, day of the week, and other factors. Although wind forecasting and power variability may be new issues for grid operators, it appears to be an extension of familiar ideas.

Summary

We understand many of the issues surrounding the use of large-scale wind power plants in regulated markets through a combination of growing experience with wind power plants and the application of various modeling methods and techniques. As the use of wind energy increases, this understanding will expand to a more empirical base and to additional wind sites. Many of these issues will also be addressed as the electricity system moves towards a more competitively based market structure.

From past work we know that wind power plants have capacity, energy, and emissions value, depending on a variety of factors. As the utility industry enters an era of increasing risks, companies will need to be fully aware of the various risks posed by the new markets. The use of large-scale wind power plants presents some risk, i.e., the risk of no wind when it is needed, but alleviates others, i.e. the risk of future fuel cost escalation or the risk of tighter constraints on future emissions levels. Some of these risks can be mitigated by good siting and geographic dispersion. These smoothing effects have been documented in both high-resolution data and hourly data, and can be substantial. It will be useful to apply existing modeling and analysis techniques to additional sites when data becomes available. Other wind-related risks can be mitigated by accurate wind forecasts to help wind plant operators bid into the electricity supply markets.

Transmission will play an important role in future development of wind. As the regulatory and market forces evolve in the newly emerging competitive markets, there are many unresolved issues concerning reasonable and fair cost allocations, incentives for market players to provide sufficient transmission, and consistent rules governing different regions. For competition to succeed, it is critical that transmission access is afforded to all technologies in a way that does not reward those players with substantial market power.

There are several other important issues that must be addressed that will play an important role in determining the success of wind power plants in the new electricity markets. They include the specific regulatory environment of the new markets, power pool rules, and bidding and settlement procedures. Significant levels of market power on the part of large generation owners will also have an important influence on the role of large-scale wind power plants in the restructured market.

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