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

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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; the former depend on the uncertain 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 consumers and power companies alike. Some would argue, however, that most risk is borne by the consumer, whereas the power company enjoys a virtual monopoly with a 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 on emission levels. In the case of wind power plants, there is the obvious risk that such plants may not produce power when it is needed; that is balanced, however, 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 free 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 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. Indeed, risk-based performance measures of power systems, markets, and generators will come into increasing use.

In this paper, we examine 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 is the measurement of available capacity (determining whether electric capacity is sufficient to cover demand), which leads us to reliability assessment and to reliability-based measures of capacity credit.

In this paper, we assume that the power generation industry includes many types of companies, ranging from small firms that own one or two generating resources, to large companies that can generate as much as 30,000 MW or more. We use "utility" here to mean power generator (or GENCO), as we straddle environments that are still regulated and those that have restructured. We also assume that at least some of these companies will hold both wind-generating and conventional power capabilities, and that restructuring is a work in progress. The electricity industry has not been down this road before; therefore, predictions about how a specific market will perform can only be answered with experience. In one of the earliest examples of restructuring, some significant changes were recently made in the United Kingdom's power system involving its electricity supply operating procedures. In California's recently deregulated electricity market, generating-supply adequacy, reliability, and capacity measurements are still very important issues. Indeed, as the "restructuring dust" worldwide continues to settle, many underlying technical issues remain to be addressed by the market. 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 National Renewable Energy Laboratory, 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). After restructuring, both of these models were enhanced for the new electricity markets; however, 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. At NREL, we think that the generating company of the future will have some of the characteristics of the many generation and transmission cooperatives that are operating today in the United States—minus the transmission and plus a profit motive. Although some of the focus and emphasis changes, competitive pressure will induce firms to assess the most cost-effective way to produce electricity, subject to profit maximization. To maintain the reliability of the electricity supply, some form of reliability-based pricing or regulation may become necessary.

The following are some questions relevant to incorporating wind plants into the generation mix: 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, deregulated environment?

2. THE VALUE OF WIND POWER PLANTS

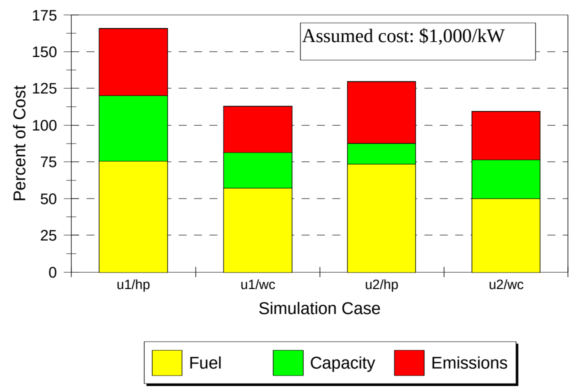
The energy value that wind power plants can provide to the grid is largely a result of the reduction in electricity generated from conventional power plants, made possible by the wind plant. We can calculate the value of offset fuel consumption and emissions using an electricity production simulation 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 used 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 with a portfolio that includes wind power plants will attempt to maximize the efficient use of these 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 changing wind patterns and their relationship to the expected load. A wind site that is attractive to one utility may not be as attractive to another. Milligan and Miller[1] 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[2], 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 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. (As agreed, the utilities were not identified.) We used two wind sites for this study, a West Coast mountain pass and a site from the High Plains. The vertical axis of the graph represents the benefit as a percent of cost, which is $1,000/kW. The diagram shows 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 resource at the plant.

Milligan also shows the results of several electricity production simulations using a chronological model. Using various combinations of utilities and wind regimes, he reveals the reduction in generation from those units on the margin during periods of significant wind generation when the chronological unit-commitment and economic dispatch are 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.

Figure 1. Value vs. cost for several wind site and utility combinations



3. 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. In this section, we assume that use of the term "capacity credit" may be more general in the newly restructured markets. We begin by discussing some general characteristics of various pool-bidding processes and the unique issues raised by wind power plants in these arrangements. Next, we discuss 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 estimates will be appropriate in the new electricity markets, however, is uncertain.

3.1 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 restructuring continues, 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. One of the emerging trends, however, is one in 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. We only describe 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. 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, like all power plant operators, has an economic incentive to bid quantities into the market that can be reasonably supplied.

There is an additional complication, however, for the wind plant operator. 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 and ancillary services, for example) 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.

The value of an accurate wind forecast depends on many factors, among them 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[3] 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 varying in accuracy from 0% to 100%. They found an asymmetrical relationship in benefits, depending on whether the wind power forecast was too high or too low. The scale of benefits depends on a variety of factors. The capacity of the wind power plant used for this study is 1250 MW, less mechanical and electrical losses and wake effects that total about 25%. The results show that there is significant benefit to an accurate wind forecast.

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, therefore, may be an accurate wind forecast for the period that is covered by the bidding process.

3.2 Reliability-based Measures of Capacity Credit

As utilities develop more risk-evaluation strategies, overall system reliability will remain critical. In this paper, we ignore the reliability aspects of the transmission and distribution grids, as the number and complexity of transactions on these grids continues to increase. However, an international panel of electric-system reliability experts recently agreed that:
(1) electrical reliability--particularly generation reliability--in the United States is very high today; (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.[4]

According to recent indications, concerns over the adequacy of the generation supply in the United States do appear to be warranted. Given the stochastic 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 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 capacity prices.

There are several ways to evaluate the reliability contribution of a single power plant to the generating system. One way is to calculate the reliability measure of choice (LOLP or expected energy not served, for example) and compare the results with and without the generator of interest. Another approach involves converting to a megawatt quantity by increasing the peak load until the reliability matches the basecase (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 its ELCC. 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.

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 and control areas, for example) Investors and GENCOs also need information to help them 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. Whether ELCC continues its useful life in the long term, therefore, may be problematic.

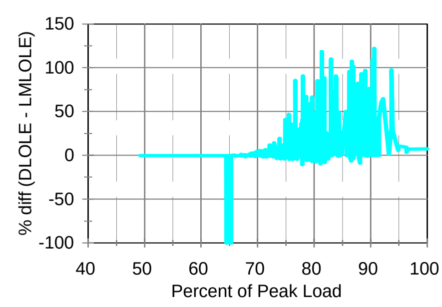
ELCC can be calculated for a wind power plant, using the same basic technique as for conventional power generators. Because wind power plants can only operate when the wind blows, the ELCC must be calculated so periods of lull are taken into account. The most accurate way to do this is to use actual hourly chronological wind power output and hourly chronological load data.

There is an additional issue involving the calculation of ELCC and other related reliability measures involving wind power plants. Conventional production simulation and reliability models do not typically 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 of LOLE as calculated by a commercial model, and then, as 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 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, the basic reliability algorithm must be adjusted so that more accuracy can be achieved.

3.3 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. In this section, we examine modeling techniques that can help assess this variation; we further suggest how these methods can be extended for generalized risk assessment.

Figure 2. Comparison of reliability measures of a wind power plant

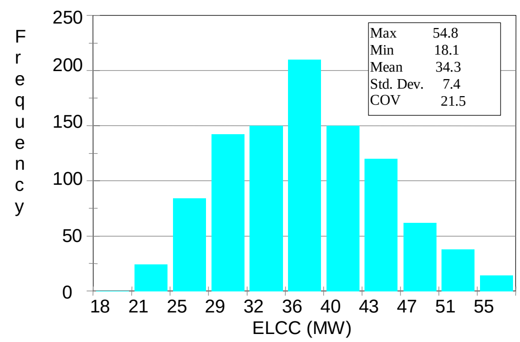


Many production-cost and reliability models have a Monte Carlo option that allows sampling from the probability distributions of generator availability. This approach is used to obtain a better estimate of the range of possible outcomes than can be provided by the usual convolution approach. Another 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[5].

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[6] illustrates such a Monte Carlo method, and it is similar to a technique proposed by Billinton and Chen[7]. Milligan[8] 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[9] 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. As the accurate assessment of risk plays a larger role in the analysis of restructured power markets, techniques such as this will become more widespread and useful.

4. 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. 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[10] analysis is based on data collected in California. Grubb[11] analyzes the effects of smoothing from wind generating units in Britain. Milligan and Artig[12] examined a reliability optimization for the state of Minnesota but did not address economic benefits. Ernst[13] provides an analysis of short-term, high-resolution wind data in Germany. And Milligan and Factor[14] examined geographical optimization using two optimization targets: reliability and economic benefit. All of these analysts found 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. In one joint project, NREL and the Minnesota Department of Public Service set out 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 Company as part of the Prairie Island nuclear waste storage agreement. Milligan and Artig applied a fuzzy-logic search technique to examine the most promising locations and sizes, evaluating the system reliability for the state of Minnesota. They found that a number of promising site combinations offered the most reliability for generating systems.

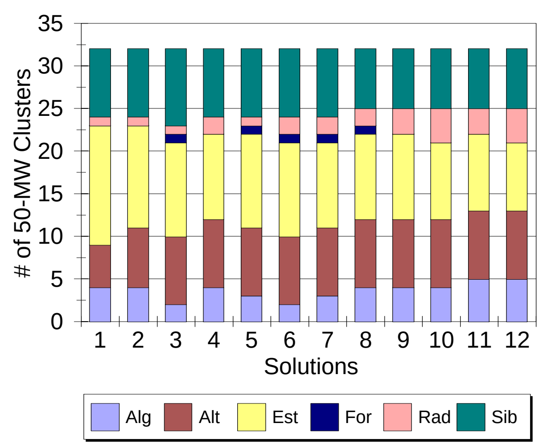
Milligan and Factor did a similar analysis for the state of Iowa, applying both a dynamic fuzzy-search technique and a genetic algorithm to the optimization process. However, in this case, there were 12 wind sites with a total installed capacity target of 1600 MW. Their model was run with projected hourly 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 5×10^9 possible ways to build 1600 MW among 12 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. In additional model runs, they identified the combination and location of sites that would maximize reliability and described these in their paper.

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 difference in 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 tested alternative site combinations that they considered close to the choices recommended by their model. They found many 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 support. This modeling process allows them to investigate the merit of building a small amount of capacity at one of the sites that were 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.

Figure 4. Top 12 site combinations based on economic benefit for Iowa



5. 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 reevaluated. Under these rules, all resources should be treated in an unbiased way, recognizing the difficulties imposed by intermittent power plants.

In their 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 address 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 between 20% and 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; this introduces additional complications into the life of the wind plant operator. 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; penalties resulting from operating practices different than those instructed by the system operator would be acceptable, however. The U.S. National Wind Coordinating Council has analyzed these and other additional transmission issues. The results are available on the Internet at http://www.nationalwind.org/pubs.

However, there are still several unanswered questions. The analyses performed in Minnesota and Iowa considered broad effects of geographical dispersion on one-hour data; however, there may be additional smoothing effects that were not considered by this model. There are other issues surrounding the short-term fluctuation of wind turbines: 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. 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. In another project, NREL is adapting 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 anecdotal smoothing effects are not yet well understood, nor is it clear how robust this smoothing effect will be to different sites around the world. There are other implications of this work. As power plant 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 may reduce the burden on regulation and other operational factors, although these are not yet well understood.

6. SUMMARY

We have begun to understand some 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. In addition, as the electricity system moves towards a more competitively based market structure, many of these issues will be addressed in the context of the new electricity markets. In the future, one key issue will be to adapt our knowledge base from the old to the new market structures.

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., 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 by geographic dispersion. Although these smoothing effects have been documented in both high-resolution data and hourly data, they are not currently well understood. However, the anecdotal evidence suggests that these smoothing benefits can be substantial. 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 the future development of wind. As 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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