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A Chronological Reliability Model Incorporating Wind Forecasts to Assess Wind Plant Reserve Allocation

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A CHRONOLOGICAL RELIABILITY MODEL INCORPORATING WIND FORECASTS TO ASSESS WIND PLANT RESERVE ALLOCATION

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ABSTRACT

Over the past several years, there has been considerable development and application of wind forecasting models. The main purpose of these models is to provide grid operators with the best information available so that conventional power generators can be scheduled as efficiently and as cost-effectively as possible. One of the important ancillary services is reserves, which involves scheduling additional capacity to guard against shortfalls. In a recent paper, Strbac and Kirschen [1] proposed a method to allocate the reserve burden to generators. Although Milligan adapted this technique to wind plants [2], neither of these papers accounts for the wind forecast in the reliability calculation. That omission is rectified here. For the system studied in this paper, we found that a reserve allocation scheme using 1-hour forecasts results in a small allocation of system reserve relative to the rated capacity of the wind power plant. This reserve allocation is even smaller when geographically dispersed wind sites are used instead of a large single site.

INTRODUCTION

As the utility industry moves toward a new market structure, many questions have yet to be answered. Many of these questions are related to how ancillary services, such as reserve and regulation, should be allocated to the various market players. Markets for ancillary services should be designed so that market participants can respond to market signals with an efficient quantity of ancillary services provided at a reasonable price. This efficient level of regulation and reserve should provide for the reliable and secure operation of the power supply.

This paper considers the market for reserves, defined as the quantity of generating capacity that is online or can be quickly brought online in cases of sudden system disturbances. These disturbances can include unexpected increases in demand and the sudden loss of generating capacity. In this paper, we focus exclusively on the hourly time step. If a system disturbance occurs during the hour, operating reserves must be sufficient to avoid an outage. The central question in this paper is not how to determine the proper level of operating reserves because different electrical control areas do not determine this in the same way. Instead, we focus on how the reserve burden, however calculated, should be distributed to the various generators in the system. The technique builds on Strbac and Kirschen's [1] proposed method, which is based on standard reliability theory and practice. Milligan [2] expands this technique by allowing for the hourly variation in wind output. However, neither of these papers considers the role of the hourly wind power forecast in the reliability calculation, which is the source of important information for the system scheduler.

In this paper, that omission is rectified, and the reliability calculation is modified so that if the forecast wind output exceeds actual output, that shortfall is counted as an unexpected "outage." When the distribution of these forecast errors is calculated over the relevant time period, the forecast power and the error distribution is computationally similar to a partial outage distribution for a conventional power plant. Using these reliability results, the system reserve can be allocated to both the wind generators and the conventional generators, as proposed by Strbac and Kirschen. A case study is also presented that illustrates the results of the method and shows that the reserve burden of a wind power plant is a small fraction of its rated capacity.

RESOURCE SCHEDULING

There are several time scales that are relevant to resource scheduling. The seconds-to-minutes time scale is called the regulation time scale. Generator output variations on this scale are typically a response to a computerized control signal. The next level is the load-following interval, which can range from minutes to hours. The unit-commitment time frame ranges from hours to days. This time scale encompasses various operating constraints that arise from physical limitations of thermal plants that make it impossible to start or stop power generation on short notice. In this paper, we focus on the time scale that sits squarely in the load-following time scale, and we restrict our attention to the hour-ahead time scale.

Generating units are scheduled in part based on their physical characteristics and in part on the economically efficient mode of operation that is unique to that plant. Given the constraints on the generator, slow-start plants such as coal or nuclear are generally scheduled as base-load units and are started and stopped infrequently, subject to minimum up-time and down-time constraints. Large base-load units contrast with quick-start units such as combustion turbines, which can be started and stopped within minutes and are not subject to the strict operating constraints of the slow-start units.

Hydro units usually have the ability to change output very quickly but may have other operating constraints. These constraints are often related to stream-flow restrictions and may impose limits on minimum or maximum output.

Wind power can only be generated when the wind blows. Often mischaracterized as an unpredictable resource, the intermittent nature of a wind power plant does indeed present unique challenges to system-scheduling operations. Constraints on wind power plants are not unique, however, because each technology has distinct characteristics and presents operators with challenges that must be overcome.

Although the technology mix in each electrical control area is unique, basic system-scheduling methods are similar. An hourly load forecast is calculated, and resources are scheduled on an hourly basis so that expected demand plus a reserve margin are met. In cases of unanticipated generator outage or higher-than-expected load, a sufficient reserve margin protects against outages. When resources are scheduled for the day ahead, all known data are taken into account. For example, if a two-unit coal plant is undergoing repairs on one of its boilers, that unit won't be scheduled. All units that can reasonably be expected to generate (given market or other dispatch rules and procedures) are scheduled, subject to demand and generator cost or price.

If a wind power plant is part of the power supply, it can participate in the same way. All known data are taken into account so that the wind power plant can be scheduled on an hourly basis for the day ahead. Although mechanical availability is also relevant to wind plants, a few turbines that are out of service in a large wind installation won't significantly impair the wind output. The main issue facing the wind plant operator is the accuracy of the wind forecast for the scheduling period. The best available forecast should be used to schedule the wind resource, just as the best available information is taken into account to schedule a conventional generator. In both cases, there may be financial penalties associated with a generator's inability to meet its scheduled output, and unanticipated excess generation may not produce profitable sales.

RELIABILITY AND RESOURCE SCHEDULING

When a buyer contracts with a seller for a given quantity of energy during a specific time period, the buyer would like some assurances that the seller can deliver according to the agreement. Some sellers may be more likely than others to fulfill their obligations. When dealing with sellers less likely to perform in accordance with the contract, the buyer might accumulate data that are based on past performance and use this data to account for the probability the seller can't deliver. Contracts can stipulate an alternative set of financial terms that are activated under these conditions. In other cases, the seller may arrange for a back-up supplier in case the contract cannot be fulfilled. Whatever the specific arrangement, some form of basic probability measure is used to help determine the likelihood that the load cannot be met.

Modern power systems have many types of markets, from fully regulated to more-or-less competitive. Whatever the market organization, schedulers learn from past experience which power resources are reliable. From a broader system perspective, it is necessary to assess the risk that the combination of scheduled resources may be inadequate to supply the load demand (in this paper, I ignore the reliability of transmission and distribution). Simple counting rules are inadequate here, although the simple counting of failures relative to power deliveries forms the basis of more complex calculations. A composite assessment of the system reliability is required, taking each supplier's track record into account. This composite assessment is called "reliability analysis." Common metrics include (but are not limited to) loss of load probability (LOLP) and expected unserved energy (EUE). Although the mathematics is not complicated, implementation of reliability calculations for a large supply system over time can be very computationally intensive. A system for which a positive EUE is calculated will not necessarily experience an outage that is induced by insufficient generation. Instead, larger EUE measures are simply indications that a higher *risk* of insufficient generation exists. I use EUE in this paper because it is widely used in the electric power industry and provides us with a tool to allocate the risk of outage to various generators. It is this risk, at least in part, that motivates power system operators to maintain a reserve margin at all times.

WIND POWER PLANTS, FORECASTING, AND RELIABILITY

Most commercial reliability and production simulation models do not adequately account for the variability of wind on a probabilistic basis. Milligan [3] introduced a sliding window technique that partially solves the problem. This approach was extended by Milligan [2] and applied to a reserve allocation method proposed by Strbac and Kirschen [1]. However, none of this work accounts for wind forecast errors, an omission that we rectify here.

To incorporate wind forecast errors into the reliability calculation, I adapted the sliding window technique so that it mimics the information that would be available to the system operator. The sliding window can be adjusted to reflect different market rules and other system characteristics. These adjustments allow the model user to choose the number of hours and days to use in the reliability calculation. If the number of chosen hours is 8,760, then the algorithm uses the forecast error distribution from the past year. Although that may be useful for planning studies, it is unlikely to be useful in operations.

Figure 1 illustrates a 6-hour sliding window. The window trails the current hour. In the example, the current hour is 7:00 AM, and 100 MW of wind output is forecast. In the preceding hours, we have collected both the actual and forecast wind power output levels, and these are shown in the figure. The first step is to calculate the forecast error for each of the 6 hours in the sliding window. These are shown at the bottom of the figure. If the actual wind output is less than the forecast output during an hour, the algorithm counts that as an LOLP event. For hours in which actual wind exceeds the forecast, this deviation is not counted toward an outage event. In these cases, zero replaces the negative forecast error for the reliability calculation.

The next step simply calculates the probability that the forecast wind power will be attained and the probabilities and associated power output levels if actual wind falls short of the forecast. Figure 2 illustrates this example: four times out of six the actual wind power at least attained the forecast, and two times out of four the actual wind fell short. The figure shows the 1/6 probability of a 10-MW shortfall, a 1/6 probability of a 20-MW shortfall, and the 4/6 probability of no shortfall.

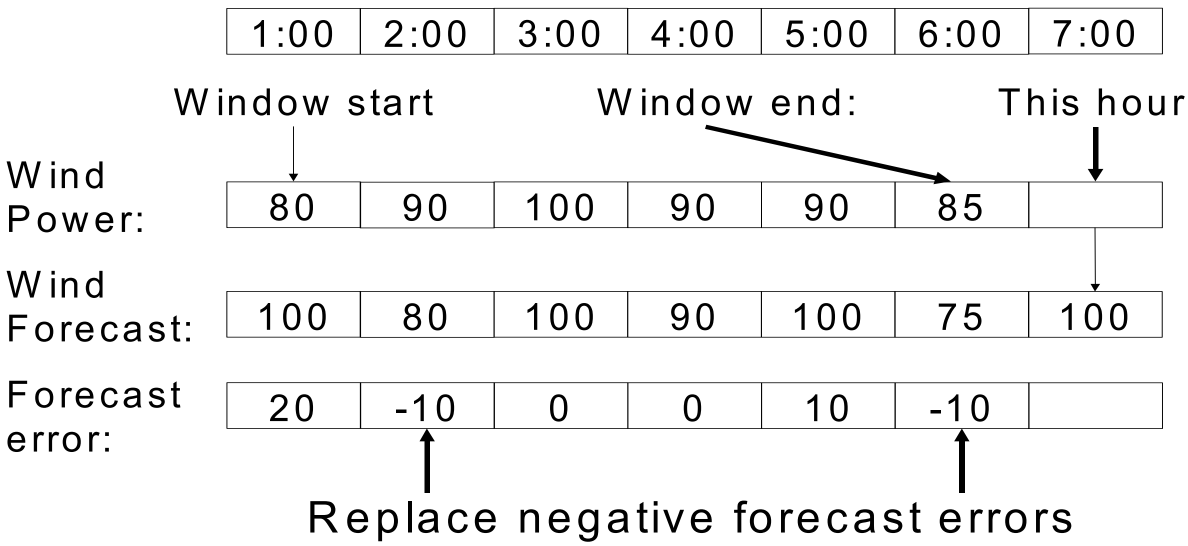

FIGURE 1. CALCULATING THE 1-HR FORECAST ERROR

The procedure advances through the year, one hour at a time. In each hour, the most recent 6-hour window is used to calculate the forecast error. The reason for this particular window size is that 6 hours approximately corresponds to the unit-commitment time scale for conventional slow-start units. The algorithm can easily be adjusted to use other window sizes if appropriate.

When we have obtained the results illustrated in Figure 2, the algorithm then convolves the wind plant into the system reliability calculation. This is done by treating the wind plant's forecast error and possible power output levels as though the plant is a conventional unit with multiple valve points and different forced outage rates associated with each output level. This technique is widely used in reliability modeling because it provides an accurate assessment of the system reliability when multi-block power plants are part of the electricity supply.

The sliding window provides the data for the forecast error, which is then used in the reliability calculation. Because the previous six hours may be too limiting, the algorithm can be altered to use forecast errors from several recent days. Figure 3 illustrates the time scale that is used for a 3-day window.

CASE STUDY: IOWA

This model was applied to data from Iowa that were used in a joint research project between NREL and the Iowa Wind Energy Institute [4]. This section discusses the statistical forecast model that was used, followed by a discussion of the simulation results.

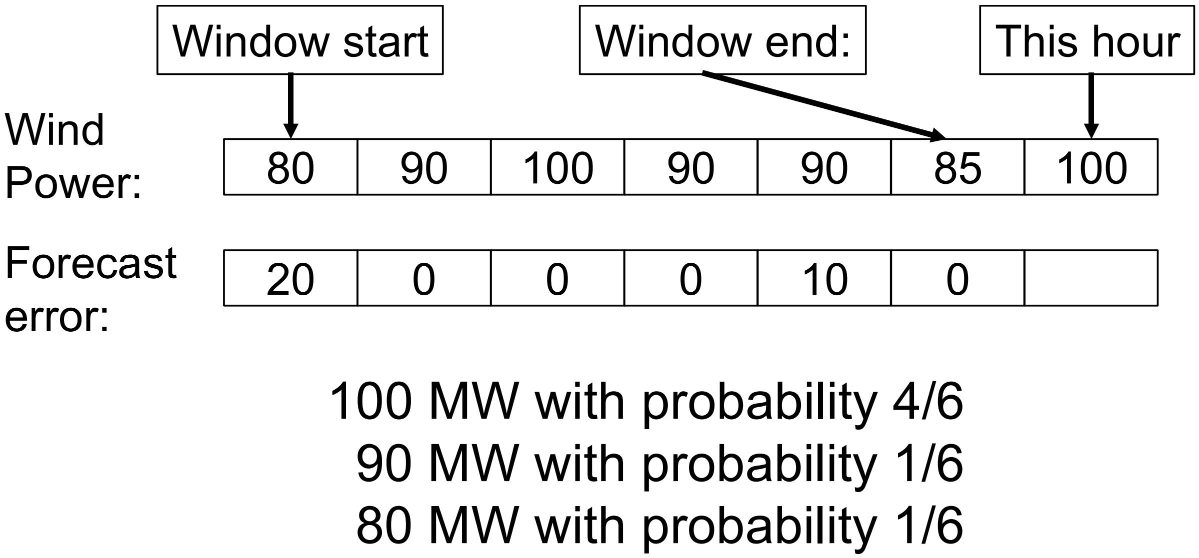

FIGURE 2. ADAPTING THE 1-HR FORECAST ERROR DISTRIBUTION IN THE SLIDING WINDOW FOR THE RELIABILITY CALCULATION

For this study, a basic multiple regression model was used as the basis of the 1-hour wind-speed forecast. In practice, it might be useful to develop wind forecasts for several hours or even several days in advance, but that is beyond the scope of this study. This forecast model was developed on the assumption that the average wind speed (and presumably power output) for the previous hour is known, (ws_{t-1} and p_{t-1}). Because the present hour, hour t, is not yet over, the only information about the wind speed is based on the emerging trend and won't be known until the hour is over. In order to develop a forecast for the next hour's wind speed (ws_{t+1}) that can be used to calculate the next hour's wind power (p_{t+1}), the model uses the trend information that is available in hour t, which is modeled as a 0 (indicating no increase in wind speed from the previous hour) or a 1 (indicating an increase from the previous hour). The wind speed from the previous hour, ws_{t-1}, is also used in the forecast model. The regression equation is:

$$\sqrt{ws_{t+1}} = b_1 + b_2 d_t + b_3\sqrt{ws_{t-1}}$$

where ws_{t+1} is the wind speed forecast in the next hour; ws_{t-1} is the actual wind speed in the previous hour; d_t is the trend variable for the current hour; and b_1, b_2, and b_3 are the regression coefficients to be estimated. The regression equation was estimated using the radical over the wind speed variables because of heteroscedasticity in the error term that was detected without scaling the wind speed.

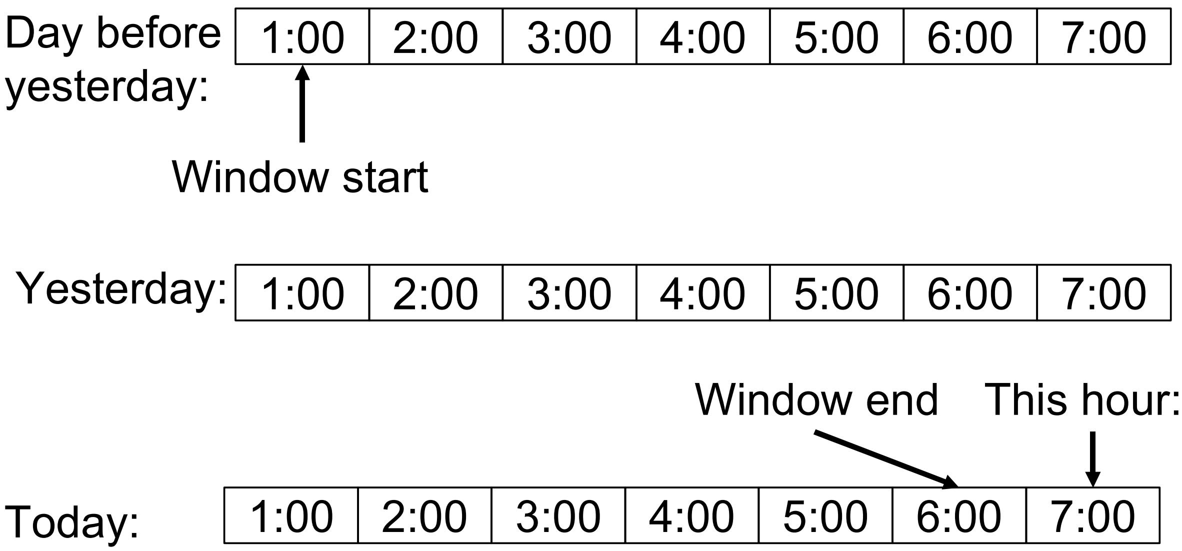

FIGURE 3. EXPANDING THE SLIDING WINDOW

Figure 4 illustrates the 1-hour forecasts for a week in July for the Estherville site. The algorithm appears to do a good job on an hour-ahead basis.

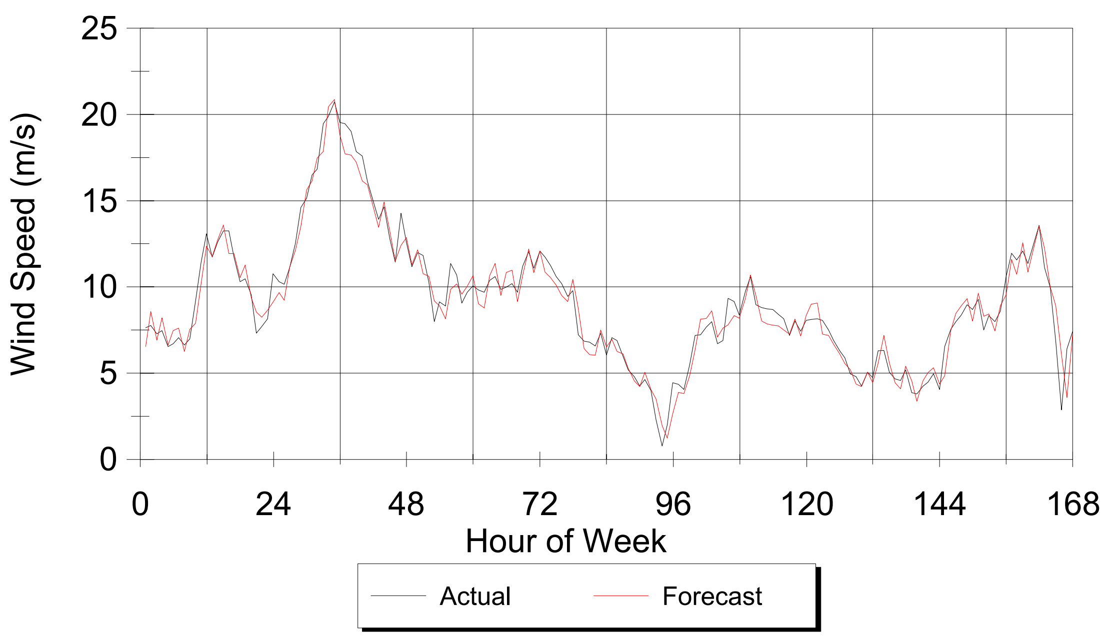

FIGURE 4. EXAMPLE OF 1-HOUR FORECAST FOR ONE WEEK DURING THE PEAK MONTH

Once the wind speed forecast is calculated, it is then possible to calculate the expected power output for the next hour. For this study, I used the Vestas V1650 turbine configured for a 1,600-MW wind site at Estherville. The hourly window was chosen to be 6 hours, roughly corresponding to the unit-commitment time scale, and the day window varied from 1-15 days in increments of 2. Because the reserve allocation can be calculated on an hourly basis, the simulation results are reported by showing the maximum, minimum, and mean values for the reserve allocation of the wind plant.

Figure 5 illustrates the results of the first set of modeling runs. The maximum reserve allocation that falls to the wind plant is about 5.5% of the rated capacity of the wind plant and occurs for one hour of the year using a day-window size of one. As the number of days in the window increases, the forecast error distribution smooths out, and this maximum reserve obligation falls to just under 2% of the rated wind plant capacity.

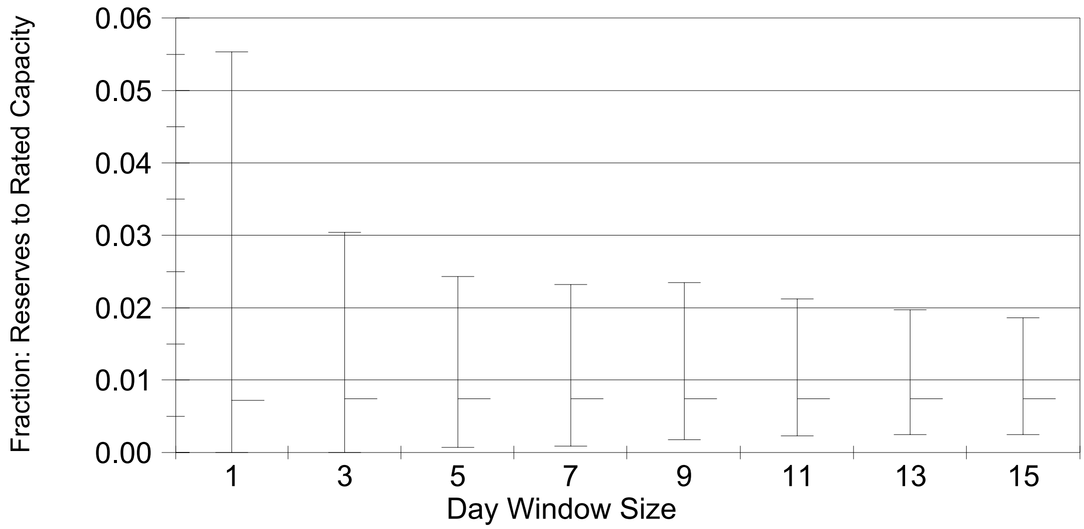

FIGURE 5. RESERVE ALLOCATION FOR WIND PLANT, BASE CASE

The middle tick mark shows the mean reserve obligation over the year for the various day-window sizes, and the highest and lowest hourly values for the year appear accordingly in the figure. In all cases, this mean reserve level is less than 1% of rated capacity, and the minimum value is significantly lower.

A number of additional cases were run so that we could get an idea how better forecasting technology would affect the reserve allocation. We did this by repeatedly scaling the wind-speed forecast errors and re-running the model. The results appear in Figures 6, 7, and 8.

In the joint study with the Iowa Wind Energy Institute [4], a number of geographically dispersed wind sites were identified. To maximize the system-wide benefit of installing large quantities of wind capacity, an optimization algorithm was applied, and several optimal or near-optimal sites were recommended for large-scale development. To explore the implication of geographically disperse wind development on reserve allocation, one of the optimal site combinations was run so that we could compare results from a single site (Estherville) with a combined site. The combined site consists of 200 MW at Algona, 250 MW at Alta, 700 MW at Estherville, 50 MW at Radcliffe, and 400 MW at Sibley. The results appear in Figure 9, which show a similar reserve allocation to the 50% forecast error reduction case that appears in Figure

7. It is likely that alternative capacity allocations at these sites, or at different sites, would result in a different reserve allocation than the one in the figure.

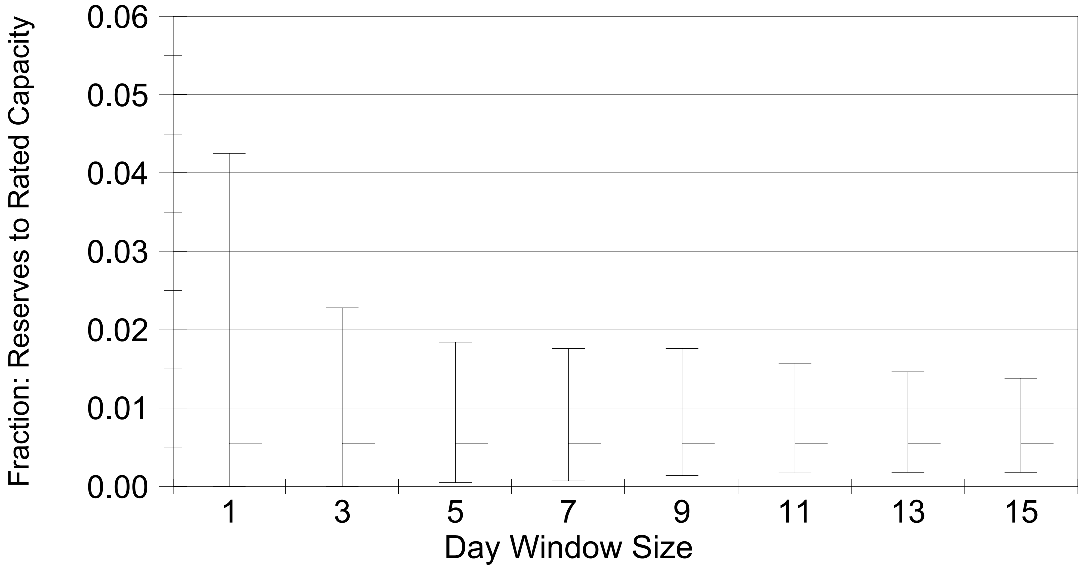

FIGURE 6. WIND RESERVE ALLOCATION WITH 25% FORECAST IMPROVEMENT

As can be seen in Figure 9, geographically dispersed sites significantly reduce the reserve burden. This combination of sites has approximately the same effect on the reserve allocation as a 50% improvement in forecasting accuracy. These results further support the development of geographically dispersed wind sites to mitigate the effects of unknown variability on aggregate wind power output.

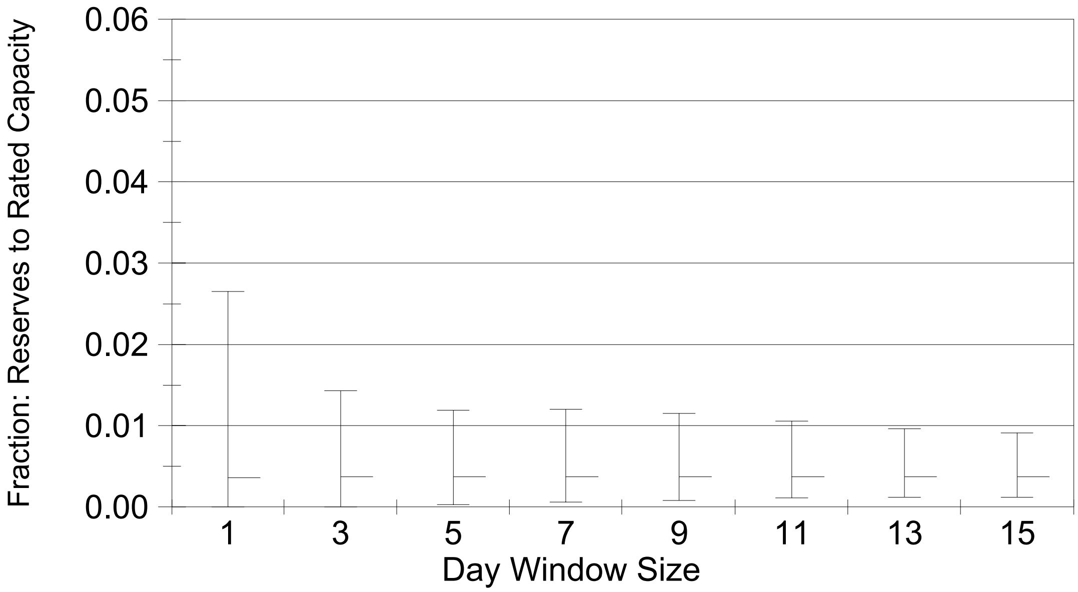

FIGURE 7. WIND RESERVE ALLOCATION WITH 50% FORECAST IMPROVEMENT

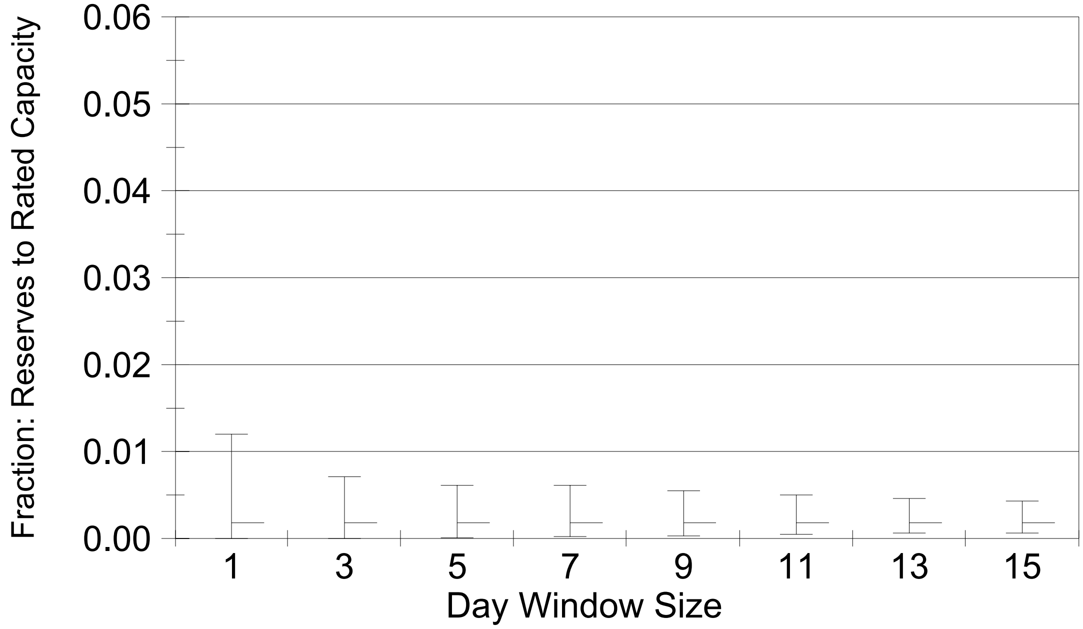

FIGURE 8. WIND RESERVE ALLOCATION WITH 75% FORECAST IMPROVEMENT

IMPLICATIONS AND APPLICATIONS OF THE METHOD

The implications of this analysis are that wind does indeed contribute to system risk, as measured by EUE. However, when the 1-hour-ahead wind forecast is taken into account, this contribution to system risk is very small compared to the rated capacity of the wind plant. Reserves are necessary because of the system-wide risk of outages, suggesting a direct link between unit reliability and outage risk. Spreading the cost of this risk to all generators in a way that encourages reliable generators and accurate forecasts provides a clear market signal to improve this aspect of system reliability. Using this method to allocate the cost of risk mitigation is not excessively burdensome to wind power plants for the system studied in this paper. The very worst case analyzed results in a reserve allocation that is less than 6% of the installed wind capacity, and the annual average reserve allocation is less than 1% of the wind-plant-rated capacity in all cases. Similar analyses should be undertaken for other systems to establish whether these results are robust to other wind regimes, load shapes, and generator characteristics.

There are a number of possible applications of this method. From an operational standpoint, this technique could be used as a true-up market-balancing mechanism. Depending on specific settlement procedures, at the end of the true-up period a post hoc evaluation could assess the reserve allocation and assign specific payments to generators. A variation of this approach could use the past year's data to establish reserve fractions for the current year. Even if the worst-case wind scenario is adopted, wind's share of the reserve burden would be less than the 7% rule of thumb that is often applied in practice, and this reserve burden falls to about 3% if the wind capacity is spread among many geographically disperse sites. This method can also be used to help determine the value of increasing the wind forecast accuracy, albeit from the limited standpoint of the reserve allocation. And during the planning stages of a wind project, it would be possible to demonstrate that wind's contribution to system risk, as measured by EUE, is not onerous.

The Iowa case study is based on 1-hour-ahead forecasts, a limitation to this study. A more complete study might include longer-range forecasts. The length of the forecast period should be determined based on the operating system characteristics, such as the level of quick-start capacity, unit minimum up-times and down-times, market structure, and other related constraints. Congruent with a longer-term forecast, the forecast method should be expanded beyond the simple statistical model used herein.

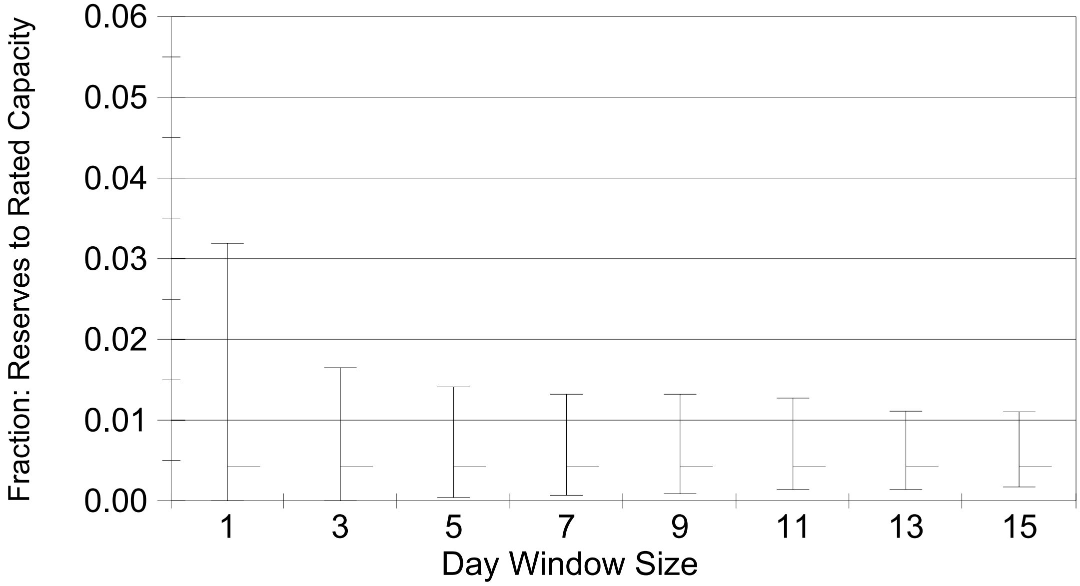

FIGURE 9. WIND RESERVE ALLOCATION WITH GEOGRAPHIC DISPERSION

CONCLUSIONS

Although the results of this case study are based on actual system data and simulated wind power data, there are many financial settlement mechanisms and a variety of electricity market structures that continue to evolve. The algorithm proposed in this paper can be adapted to those markets and can use more sophisticated forecasting methods and longer forecast periods.

Even though wind power output can be highly variable, it can be predicted with a reasonable degree of accuracy in the 1-hour-ahead time scale. Once the forecast error distribution can be estimated, it is possible to calculate the risk posed by wind forecast errors relative to the risk of other power plant outages. Using standard reliability calculations and a variation of the reserve allocation proposed by Strbac and Kirschen, we find that the reserve allocation to wind power plants is a small percentage of the wind plant rated capacity.

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