Reducing the Variability of Wind Power Generation for Participation in Day Ahead Electricity Markets

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Abstract

Uncertainty and variability in the wind resource create obstacles for the participation of wind power in forward markets, such as regional day ahead electricity markets. Studies performed in various states have developed methods to improve wind forecasting and so reduce the inherent uncertainty in a day ahead schedule for wind power generation. This paper addresses the issue of the variability in wind power generation by estimating the next ten-minute production level for a hypothetical wind farm, and then dispatching additional dedicated resources, such as responsive load or a gas turbine, in order to reduce the net variability of the generation in the next ten-minutes. Historical wind data from ISO-ne are used with an auto-regressive moving average model to develop the next ten-minute forecast. Preliminary results estimate the capacity required for the dedicated resources to maintain the wind output within a specified percentage of the submitted day ahead schedule.

1. Introduction

The installed capacity for wind power in the United States is projected to increase substantially in response to interest in low-emissions power sources and a desire to decrease the national dependence on imported petroleum. From its current level of less than one percent of national electricity sales, wind power generation could grow to a level of twenty percent of retail electricity sales, in Minnesota for example, by the year 2020 [1]. The extent of uncertainty and variability in wind generation makes this resource different from the traditional, dispatchable generation resources, with the result that wind power generation cannot be readily integrated into standard system operating procedures. At relatively low levels of installed capacity, wind turbines and the output from large wind farms can essentially be absorbed into traditional system operations without degrading system reliability. At the current higher projected levels of penetration, wind power requires more sophisticated mechanisms to maximize its participation in the power system without penalizing it for the unavoidably intermittent nature of its resource.

The development of electricity markets offers new opportunities for the operators of wind farms, as the widespread use of locational marginal prices allows wind generation to be sold in real time markets and receive this standard price. Participation in forward markets is also important in order to allow wind farms to receive credit for their contribution to installed capacity (and therefore to system reliability). In addition, advances in wind forecasting and turbine controls suggest that wind power could soon be participating in ancillary services markets. Nonetheless, the persistence of rules that penalize scheduling deviations along with the lack of system and market operator experience with intermittent resources create obstacles to the projected large increase in wind turbine installed capacity. This paper investigates the option of pairing wind generation with a second, dedicated resource, in order to reduce the net variability of the wind power output, and so allow wind to participate more fully in markets. The proposed method could be used by wind farm operators to facilitate bidding the net wind power into regional day ahead electricity markets, and to receive compensation for the contribution of wind generating capacity to system reliability .

Section 2 discusses the government regulations and recent state-level developments related to the participation of wind generation in electricity markets. Section 3 reviews some current demand response programs that could be expanded to allow load to respond to variations in wind output in addition to, or instead of, responding to price or reliability-based signals. Section 4 introduces the auto-regressive moving average, ARMA, model used in analyzing the wind resource data and developing a "next hour" and "next ten-minute" forecasts. Section 5 presents the results of the modeling and quantifies the capacity that would be required from each of the paired resource options in order to maintain the net wind generation output to within five and fifteen percent of the submitted day ahead schedule. Section 6 presents conclusions and future work.

2. Wind power and electricity markets

Typical electricity market structures, as operated by Independent System Operators (ISO) in the United States, include day ahead, hour ahead and real time markets, with an increasing number of ancillary services markets as well. The majority of these markets have transmission service offered through tariffs designed under FERC Order 888. Orders 888, 889 and 2000 include rules and regulations that also impact many of the rules in the electricity markets. Of primary significance to intermittent resources, such as wind power, is the Order 888 provision that financial penalties can be levied on market participants that deviate from their day ahead schedules by more than ±1.5 percent.

These penalties are intended to persuade market participants to be as accurate as possible in their day ahead schedules, and presume that it is in fact possible to submit a schedule that will be within 1.5 percent of the real time generation and load. The inherent uncertainty in meteorological data means that wind generators are unable to reliably predict the next day's generation with this level of accuracy. The result is that, when expected to meet the scheduling accuracy of FERC Order 888, wind generation cannot participate in the day ahead markets without incurring significant penalties in real time. FERC began investigating a mechanism to remove the scheduling deviation penalties for intermittent resources in the notice of proposed rulemaking, RM05-10. The proposed rulemaking was withdrawn in April, 2007 as discussed in [2].

In addition to removing penalties associated with schedule deviations, it is important to find mechanisms that allow wind to be acknowledged for its contribution to system reliability. One method would be through participation in day ahead markets. Though the full nameplate capacity of installed wind turbines will not count toward generation adequacy, some fraction will. Recent studies have estimated this capacity value to be between 10 and 41 percent, with an average of 20 percent in California [3], between five and twenty percent in Minnesota [1] and an average of 30 percent in New York State [4]. A second motivation for encouraging wind participation in day ahead markets is to transform the perception of wind power from that of negative load to that of a capacity resource. In real time markets, and at low levels of penetration, wind is treated as negative load. Through participation in day ahead markets, wind could be integrated into system and market operations as a generating resource that could provide not only energy but also capacity and ancillary services [4].

A variety of approaches have been investigated and implemented to facilitate increased participation of wind in day ahead markets. The easiest mechanism is simply to waive the schedule deviation penalties for wind power generation, as has been done by the New York ISO, ISO New England, PJM and ERCOT [5], [6]. One step beyond simply waiving the deviation penalties would be a market rule allowing all energy provided in real time to receive the LMP. This rule was promoted by FERC as part of the standard market design rulemaking, and is implemented for wind power in a number of ISO markets [5].

As interest in wind generation grows and regional expansion plans include possibilities for significant wind capacity, simply waiving schedule deviation penalties does not adequately address the underlying issue however – that uncertainty and variability in wind generation do impose real costs on system operation in terms of efficient unit commitment, and through providing services such as balancing and regulation.

The issue of uncertainty in wind generation can be addressed by improving the accuracy of forecasting the wind resource. To this end, the Minnesota Public Utilities Commission ordered a study to investigate the impacts of incorporating wind generation at the level of 20 percent of retail electricity sales by the year 2020 [1]. For this study, sophisticated meteorological modeling was performed by WindLogics [7] for the years 2003, 2004 and 2005. The results of this study demonstrated that the day ahead forecast errors were as low as 20 percent. In addition, the broader analysis as performed by EnerNex found that as spatial and geographic diversity of the wind turbine sites increased, the error decreased by up to 43 percent [1].

A second state to actively investigate a mechanism to facilitate the participation of wind power in the day ahead market is California. In 2004 FERC approved California's plan for its Participating Intermittent Resource Program, PIRP [8]. In this program, intermittent resources such as wind and solar agree to telemeter local meteorological data and real time power generation to the California ISO. For wind farms, the ISO then sends the meteorological data to a designated wind forecasting company [9] which has contractually agreed to provide both day ahead and hour ahead forecasts. If the participating resources submit schedules consistent with the forecasts, then they are not subject to penalties for deviations from the forecasts. The financial settlements for the PIRP occur at the end of each month, with the wind generators being charged a weighted average price for the net monthly deviations. This value will approach zero as the accuracy of the forecasts improves. The PIRP in California has been operating since August 2004, and currently has 600MW of wind generation enrolled (equal to 22 percent of the state's installed wind capacity), with the cumulative average deviation of the forecast close to one percent for 2005 and 2006 [10].

These programs demonstrate that wind forecasting decreases the uncertainty in day ahead schedules, and when combined with flexible market structures and settlements facilitate increased involvement of wind power generation in the day ahead markets. The inherent variability in wind generation remains though, even as the uncertainty is reduced. To address the variability inherent in wind output, this paper investigates the possibility of pairing wind output with responsive demand, in order to reduce the variability in the net wind output. Recent advances in demand response that would enable this pairing are discussed in section 3.

3. Demand response and wind variability

To a large extent, load exhibits the same characteristics – uncertainty and variability – as wind power. Load patterns though, have been more extensively studied for many years and so are better understood and more accurately forecasted than the wind resource. The purpose of this effort in load modeling is to understand load patterns well enough to operate the power system through the control of individual generation and transmission facilities, in order to serve load and maintain system reliability. Thus, load is extensively modeled and *other* facilities are controlled to serve load, with relatively little effort made to control load itself. This trend is not absolute, as there are traditional utility mechanisms, such as interruptible contracts and direct load control, to reduce load at times when system reliability would otherwise be threatened. There is also persistent interest in developing mechanisms for more dynamic load response for both reliability and economic purposes.

Recent efforts to allow load to be more responsive to system conditions and a more active participant in electricity markets arise for multiple reasons. In addition to giving customers incentives to decrease their demand in the short run to improve system reliability during times of system peak, demand response can be used in the long term to decrease required capacity expansion and lower total costs. Demand response is also an important and essentially absent element in electricity markets. If it were to be more widely implemented, market efficiency would be likely to improve. The following section introduces demand response programs in three regions of the country, that reveal significant customer interest in these programs. This is followed by a brief discussion of enabling technologies.

3.1. Regional demand response programs

Responding to incentives for increased demand response, utilities and regional system operators throughout the country have implemented a variety of such programs. Building upon the long standing peak/off-peak pricing program, various regions have implemented a critical peak pricing program, CPP. This program offers peak/off-peak rates for most days, with a third, higher rate applicable during designated critical peak events, for which the operator send alerts to program participants. In California, CPP is offered by the three major utilities to residential, commercial and industrial customers. In aggregate, homes participating in CPP, and that are equipped with advanced demand response technologies (for automatic response) have been able to reduce their demand 20 percent overall relative to non-CPP homes, and up to 50 percent during summer super peak events [11].

As a second example, in the late 1990s in Chicago, a local non-profit organization (the Center for Neighborhood Technology) and Commonwealth Edison partnered to create the Community Energy Cooperative (CEC) [12]. The CEC in turn developed the Energy Smart Pricing Plan, a residential real time pricing program, that began in 2003 [13]. In the first two years of operation, participants in the program decreased their overall electricity consumption by up to 20 percent, saving 15 percent on their electricity bills [12]. Enabling technologies such as interval meters and automatic air conditioner cycling have led to positive customer response to the program, which is being expanded in 2007 so that all customers will have the option of receiving a real time electricity price.

A third example is New England, which has a variety of demand response programs, ranging from long term direct load control contracts to programs for real time pricing (though currently the real time pricing program relies on hourly prices published a day in advance so participants can plan their next-day demand pattern). The peak demand for New England in 2006 was 28GW with the total demand response potential estimated to be 2800MW, approximately 10 percent of peak [14]. Regionally, only 2.6 percent of load is enrolled in demand response programs. Southwest Connecticut, which frequently suffers from transmission congestion, has achieved 6.8 percent load enrollment in demand response programs, equal to 506 MW of load. The Southwest Connecticut estimated potential for demand response is 700 MW [14].

3.2. Demand response technologies

This section provides a brief overview of some current demand response technologies that could be used to allow customers to alter their demand level in response to wind power generation variability. Facilitating the advances in demand response capability are new technologies such as interval meters (which measure electricity usage in 10 to 15 minute increments), smart chips for appliances (such as those being developed at Pacific Northwest Laboratories [15]) and internet-based automated demand response for heating, air conditioning, and other appliances in residential, commercial and industrial facilities. California's Demand Response Research Center [16] analyzes advanced demand response technologies. The three major California utilities have also equipped customers with smart thermostats and an always-on gateway to control groups of appliances [17]. Major utilities across the country, including California and New York, are installing smart meters throughout their service territories. Surveys of the Energy Smart Pricing Program in Chicago indicate that customers found participation to be easy and readily accepted automatic air conditioner cycling. This program has enjoyed an average retention rate for three years of 95 percent [18], [19], indicating customer acceptance of the need to alter their demand patterns in exchange for lower overall electricity bills.

4. Development of the analysis model

This section discusses the modeling of wind power data performed for this paper. The analysis presented below proceeds along the following stages. First, wind speed data for New England locations was obtained from [20]. The wind speed data were converted to wind turbine power output as discussed in section 4.1. The regional wind power generation data were analyzed with an ARMA model of order one, in order to develop an hour ahead and a next-ten-minute forecast, as presented in section 4.2. Finally, the development of a day-ahead forecast is discussed in section 4.3.

The goal of this modeling is to develop three data sets that can be compared and analyzed in order to quantify both the variability in the wind output and the subsequent capacity of a dedicated resource required to mitigate this variability. If a dedicated resource, such as demand response, can be used to reduce the net variability of the wind-plus-demand-response output, then the combined resource will present a more predictable and controllable (*i.e.,* dispatchable) resource, facilitating the integration of the wind resource into system and market operations.

The three data sets developed for the analysis in this paper are a day-ahead wind generation schedule (or forecast), an hour-ahead schedule, and a next-ten-minute forecast. The error between the day-ahead and hour-ahead schedules can be met with slower responding (30 minute to one hour) resources, while the error between the hour ahead and next-ten-minute forecasts can be addressed with fast responding resources, such as automatic demand response systems [15], [16], [17].

4.1. Converting wind speed data to wind turbine power output

The basic properties of the wind are its speed, direction, and fluctuations in this speed and direction. These properties are affected both by local terrain, in terms of vegetation, buildings, and topography, and by the height of the wind above these features. The relationship between wind speed and height is shown in the equation below, where speed increases from V_1 to V_2 as height increases from H_1 to H_2 [23]:

$$V_2 = V_1(H_2/H_1)^a \qquad (1)$$

The exponent, a, depends on atmospheric pressure and stability, as well as the roughness of the terrain and wind direction. A standard lower value for 'a' is 1/7, which loosely represents most terrains. This value is not appropriate for use with mountain ridges, which have rather extreme terrain; an upper boundary for 'a' for New England was calculated from data for Stratton Mt. VT at a value of 0.426. A conservative value of 0.250, between these two boundaries, is used in this analysis. The hub height of the turbine (H_2) is further modified by the height of the tree canopy by decreasing the effective hub height by ¾ of the tree height [24].

Wind speed is an important characteristic of the wind, yet for wind power generation is ultimately concerned with the power in the wind, and not specifically with its speed. Equation (2) relates wind power to wind speed, where P_w represents the power in the wind, ρ the air density, A the area swept by the turbine blades, and v the velocity, or wind speed

$$P_w = (½)\, \rho A v^3 \quad (2)$$

To estimate the power captured by the wind turbine, the effect of the rotor on the wind must be taken into account. As the turbine extracts energy from the wind, the wind will begin to flow around the rotor rather than through it, until in the limit there would be no wind moving through the rotor at all. The wind begins to flow around the rotor when the wind speed of the wake is 1/3 of the incident wind speed, or when the rotor experiences a wind speed 2/3 of the incident speed, which marks the maximum possible power extraction from the wind. With these limits on the wind speed experienced by the rotor, the maximum power extraction by the turbine, P_T, can be calculated as [25]

$$P_T = (16/27)^* (½)\, \rho A v^3 \quad (3)$$

Future work will rely on the using the power curve from a specific wind turbine technology. The results in this paper rely on (3) for calculating the power generated by a wind turbine.

4.2. Auto-regressive model for wind power

The area of wind forecasting is advancing rapidly and many sophisticated models exist for forecasting wind speeds over various time horizons [1], [7], [8], [9], [10]. For the purposes of this paper, we develop a first-order ARMA model, as has been used in early wind speed and wind power forecasting [21], and proposed here predominantly for use in forecasting the next-ten-minute wind power output. The purpose of this model is to provide a basis for developing a mechanism to forecast wind output variability, at the wind farm level, and then mitigate this variability through the use of an alternative, dedicated resource such as demand response. Although a more sophisticated forecasting technique would improve the accuracy of the forecast, it would also likely require more time to actually calculate the forecast. The approach used here, of a first order ARMA model, is sufficient for our exploration of using dedicated demand response resources for reducing wind power generation variability, and is also fast enough to be implemented for the ten-minute time frame.

Wind speed data at ten minute intervals was obtained from the University of Massachusetts historical data archives [20], for Dartmouth, MA in the ISO-ne region. The wind speed data was converted to theoretical wind power output using the relationship described in Section 4.1. The development of the day-ahead forecast is discussed in section 4.3. For developing the forecasts for the next hour and next ten-minute wind power generation, a first order autoregressive model is used. This model takes the form:

$$X_t = \alpha + \beta X_{(t-1)} + \varepsilon_t \quad (4)$$

The resulting parameters for this model are summarized in Table 1.

Table 1. Autoregressive model parameters

parameter	10 Minute-Model	Hour-Ahead Avg. Model
α	0	0
β	0.96	0.98
R^2	0.92	0.96
Standard Error	99.5	70.3

It is interesting to note that the accuracy of the average hour-ahead AR(1) model is slightly higher than the model developed for the 10 minute-ahead prediction. However, the hour-ahead model uses the previous hourly average to predict the average wind generation in the next hour. The effect of averaging this data over six ten-minute time intervals is to dampen the fluctuations. As a result, the AR(1) is slightly more effective at predicting hour-ahead than 10-minute ahead observations.

Sample results of these models applied to the forecasting of hour-ahead and 10-minute ahead time series are provided in Figures 1 and 2, respectively.

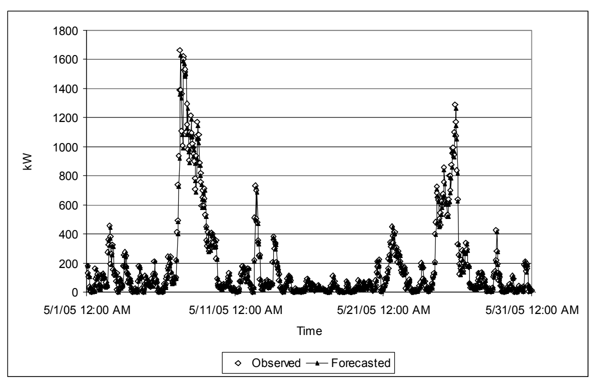

Figure 1. Sample hour-ahead AR(1) results

The figures plot both the observed data, as obtained from the UMass historical data along with the coincident forecasts. Visual inspection of the time series in Figures 1 and 2 indicate that the AR(1) forecasting model, while not sophisticated, provides a reasonable basis for discussing the framework presented in this paper.

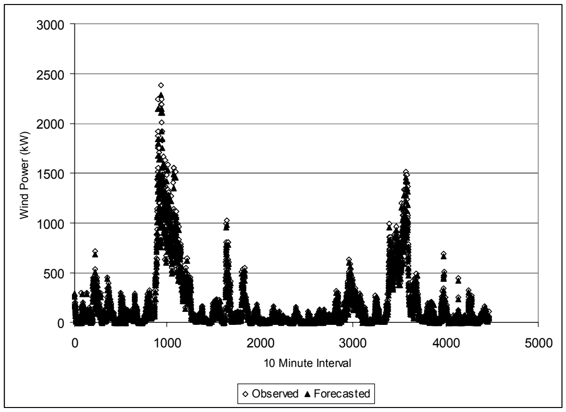

Figure 2. Sample 10 min-ahead AR(1) results

4.3. Developing a day-ahead forecast

If the analysis presented in this paper were implemented for an actual system, it is assumed that a day ahead forecast from other sources would be available. For the purposes of the analysis in this paper a day-ahead forecast for wind power generation was created by introducing error into the known day-of wind power generation. A similar method for simulating forecasting errors has been presented in [22]. To be consistent with actual forecasting errors, data from an analysis of the observed errors in the day-ahead forecasts of the CAISO PIRP were utilized [8]. These results for the first year of the PIRP found that for 26 percent of the day ahead forecasts, the error is within four percent of the installed capacity, and further that only 8.3 percent of the hours have an error that exceeds 40 percent of the installed capacity [8]. The histogram of the day-ahead wind forecast errors presented in [8] forms the basis of this analysis, and is show in Figure 3.

The distribution of errors is loosely represented by moment matching to a Gaussian distribution, as is overlaid in the figure. To produce a simulated day-ahead generation schedule for the wind generation in this paper, errors drawn from this random distribution are added to the available wind power data. In essence, known wind power generation potential is corrupted with errors similar to those that would be expected in an actual day-ahead forecast. The resulting time series is used as the day ahead dispatch schedule for the wind generator.

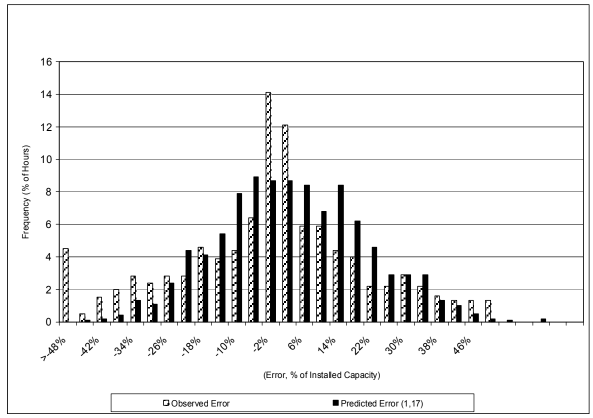

Figure 3. Distribution of day ahead forecast errors

The uncertainty of this forecast is a key element in the results of the analysis, and future work includes analysis of sensitivity to the form and parameters of the error distribution.

5. Pairing the wind resource with other resources

The goal of this work is to determine the feasibility and the capacity required to use an alternative resource to dampen both errors in wind generation forecasts and also the inherent variability in real-time wind power generation. Related work is presented in [26]. The initial investigation presented in this paper considers the errors between the day-ahead schedule, discussed in Section 4.3, and the hour-ahead and 10-minute ahead forecasts. As a mechanism to reconcile first, the hour-ahead schedule with the day-ahead schedule, and second, the ten-minute schedule (real-time output) with the hour-ahead schedule, we propose pairing demand-response resources with the wind generation in order to have the demand respond to wind variability rather than (or in addition to) price and reliability signals.

Specifically, demand response resources will be used to partially balance deviations between the day ahead, hour by hour, schedule and the hour ahead forecast. Once the hour ahead forecast is completed, slower responding resources can be dispatched to partially balance the deviation between the original day ahead schedule and the current hour ahead schedule. In this analysis we propose to mitigate 50 percent of the estimated MW deviation between the day ahead and hour ahead schedules using the demand response resources. Preliminary analysis indicated that excessive cycling of the resources would occur if the entire scheduling deviation were mitigated based on the hour ahead forecast, since the next-ten-minute forecast will introduce additional adjustments. Accordingly, the generation forecast is re-assessed ten minutes ahead of dispatch, and fast response resources are adjusted to mitigate the additional deviations predicted at this shorter timescale.

5.1. Day-ahead to hour-ahead deviations

For an illustration of this approach, we first compare the day ahead schedule (described in Section 4.3) to the hour ahead schedule (discussed in Section 4.2). The result of this comparison is a MW value of generation shortfall or excess expected between the day ahead and hour ahead schedules. Based on the magnitude of this discrepancy, a decision will be made whether to activate the demand response resource or not. The purpose of this assessment an hour ahead of dispatch is to take advantage of the additional weather information available and to be able to utilize slower responding resources to mitigate the expected scheduling deviation.

Since further deviations are expected between the hour ahead schedule and real time output though, the paired demand response resource will never be dispatched to meet completely the deviation between the day ahead and hour ahead schedules. Instead, a specific deviation threshold, or dead band, is specified, inside which the demand response resource will not be dispatched. Finally, when the alternative resource is dispatched based on the schedule deviations, it is only called upon to mitigate 50 percent of this anticipated deviation. The remaining excess or shortfall in wind power output will be addressed with faster responding demand response alternatives, to be dispatched after each next-ten-minute forecast is made.

Figures 4 and 5 illustrate one possible outcome for one month of operation of a hypothetical 1MW wind turbine in Dartmouth, MA. Each figure quantifies the number of hours of the demand response (or any alternative) resource requirement over the course of each day of the month, for the given threshold, or level of variance. Figure 4 illustrates the case of a five percent threshold; if the hour ahead forecast is more than five percent above or below the day ahead schedule, the alternative resource is dispatched in order to mitigate 50 percent of the deviation. Figure 5 illustrates the same scenario with a 15 percent threshold.

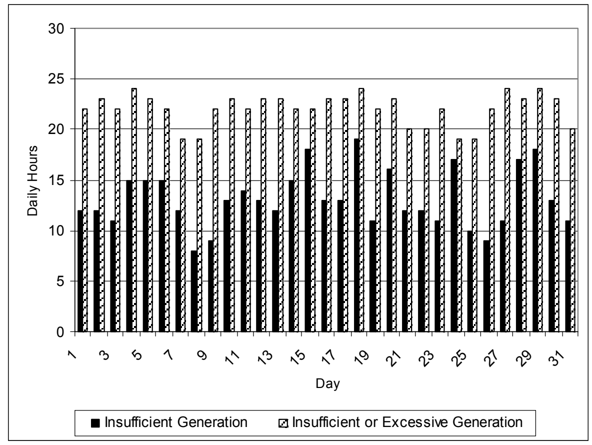

Figure 4. Daily hours of alternative resource required (five percent threshold)

These figures show, for example, that for a five percent threshold, 27 days in the month would require between 20 and 24 hours of access to the paired resource in order to adequately mitigate the variability in the wind generation. This drops to 15 days required for a 15 percent deviation threshold. These figures indicate a need for significant access to the capacity of the paired resource in order to mitigate the scheduling deviations in the wind generation.

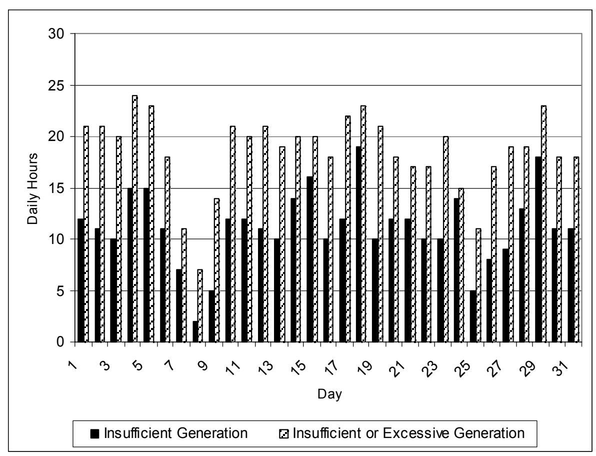

Figure 5. Daily hours of alternative resource required (15 percent threshold)

The magnitude and frequency of the required dispatch for the alternative resource in the hour-ahead time frame are plotted in Figure 6. This figure illustrates the approach for the hypothetical 1MW wind turbine in Dartmouth, MA. We consider that the alternative resource will be dispatched to cover 50 percent of the deviation between the day ahead and hour ahead wind generation schedules.

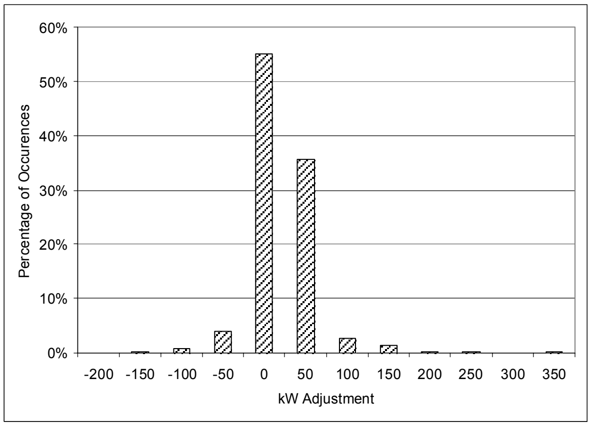

Figure 6. Histogram of hour-ahead adjustments

This figure shows that for more than 50 percent of the time, the paired demand response resources are not required to be dispatched. For 36 percent of the time, a dispatch of 50 kW is required (five percent of the 1 MW turbine capacity) If this were scaled, to a proposed 30 MW wind farm for Florida, MA for example [27], 1.5 MW of slow responding demand response resources in New England would be required to be dedicated to balance these hourly wind farm scheduling deviations (*e.g.,* for 36 percent of the hours). This capacity is well below the regional potential of 2,800MW.

For reliability-based demand response in New England, resources that respond within 30 minutes are paid \$0.50/kWh. Alternatively, price-based programs guarantee participants a minimum price of \$0.10/kWh [28]. These translate into costs between \$150 and \$750 per hour for the dedicated demand response to mitigate the day ahead to hour ahead scheduling deviations. For 36 percent of the hours during the month, this translates to a cost of \$40,000 to \$200,000 per month. These costs represent a worst case scenario, since the variability in the wind output will decrease significantly as the geographic diversity of the wind farm is increased [1]. Also note that the cost estimates presented above are based on linear scaling of the results for the 1MW modeled turbine. These estimates will be improved in the next stages of this analysis, as discussed in section 6.

In comparison to the costs for demand response, ten percent of the capacity of a 15 MW gas turbine could be dedicated to respond to the wind generation variability. For small gas turbines, the cost of electricity is estimated to be \$0.11/kWh [29], close to the lower bound for the demand response resources. For new gas turbines, ramp rates of 55MW/min down to 13.7MW/min are possible [30].

5.2. Hour-ahead to ten-minute-ahead deviations

The next step in the proposed resource pairing approach is to reassess the wind power generation forecast at ten minutes prior to dispatch. In this time frame, the forecast is more accurate, and requires faster response from the dedicated resources. Ten minutes before dispatch, the deviation between the hour ahead wind generation schedule, the hour ahead alternative resource schedule, and the ten minute forecast is assessed and further adjustments enacted; as quantified in Figure 7. This figure shows that for 80 percent of the time, the required adjustment of the alternative resource dispatch is between -100 and 100 kW (ten percent of the 1 MW turbine capacity modeled). To balance these deviations, demand response resources able to respond within ten minutes will be dispatched. These resources are likely to be part of automatic demand response systems, as discussed in section 3.

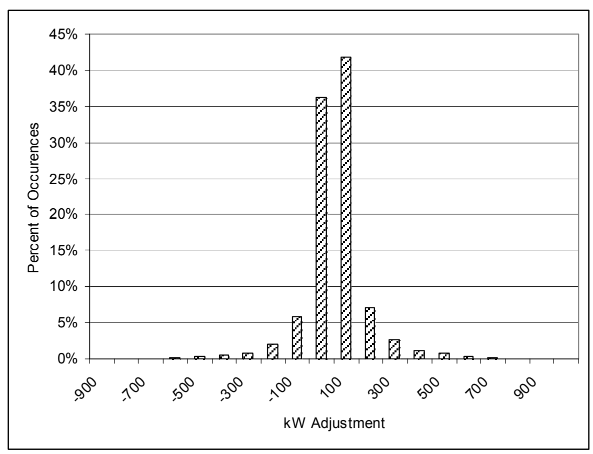

Figure 7. Histogram of 10 minute-ahead adjustments

It is interesting to note that the distribution of adjustments at 10 minutes ahead of dispatch shows some larger deviations than those adjustments made based on the hour-ahead forecast. The reason for this is two-fold; first, there are many more observations at the 10-min intervals than at hour intervals, and the hour ahead fluctuations are dampened by the averaging effect previously discussed. As a result of the six-fold increase in observations, there are significantly more opportunities for larger realizations from both ends of the tail of the distribution.

This illustrates that the effect of uncertainty in the forecast is perhaps the most important factor in the sample scenario presented here. Clearly, as more accurate forecasting techniques are employed, better decisions can be made at each time scale. An important step in exploring the validity of the framework described here would be an assessment of its sensitivity to reduction of uncertainty in the wind forecast.

6. Conclusions and future work

In general, the uncertainty and variability in load is accepted as the basis for power system operations. These same characteristics in the wind resource raise significant obstacles for the integration of wind power generation into system and market operations. This paper introduces an analysis of pairing wind generation with dedicated demand response resources in order to decrease the net variability of the wind generation. The preliminary analysis, for a single 1 MW turbine, indicates that approximately five percent of the turbine capacity, or 50 kW, would need to be matched by slow responding demand response (or other) resource, with an additional 10 percent of faster responding resources, in order to reduce the net schedule deviations to 15 percent. The lower end of the cost estimate, based on real time pricing programs in New England, is $1,200,000 per month, for a 30 MW wind farm.

The next stages for this analysis will focus on making the analysis more widely applicable and robust, through analysis of multiple years of wind data (as opposed to the single month presented above), as well as analysis of aggregated output from multiple wind farm locations. These proposed improvements upon the analysis presented in this paper are anticipated to reduce the uncertainty and variability in the net wind generation, which will reduce the required reliance upon and cost of the dedicated demand response resources.

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