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Estimating the System Costs of Wind Power Forecast Uncertainty

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***Abstract*—**Uncertainty in forecasts of wind power generation raises concerns of integrating wind power into power system operations and electricity markets at acceptable costs. The analysis presented in this paper uses an optimal power flow (OPF) model in a Monte Carlo Simulation (MCS) framework to estimate the additional cost of power system operation with uncertain output from a wind farm. A base case dispatch is established along with alternate dispatches based upon a probability distribution of real time wind power generation. The cost of the uncertainty in wind power forecasts is then quantified in terms of the difference in production cost between the base case and the cost for system dispatch under scenarios drawn from the distribution of real time wind power generation. Using various regional load levels and ramp capabilities of other generators, the results from the OPF and MCS show that wind power forecast uncertainty for the test system can increase production cost between 2.5% and 11%.

***Index Terms*—**Wind power integration, Monte Carlo simulation.

I. Introduction

All forms of electric power generation have uncertainty associated with their output level, though significantly more concern surrounds the output from wind turbines than from conventional steam generators. The research discussed here presents a method for quantifying the system costs associated with the uncertainty in the forecasts of wind power generation. This project is part of a larger project developing methods to integrate wind power into electricity markets.

A number of studies present sophisticated forecasting techniques [1], [2], [3]. The methods and results presented in this paper examine the impact of forecasting errors between the hour ahead and real-time market phases. Issues for market integration are discussed in [4],[5]. The research presented in this paper includes the effect of transmission system in modeling wind power as part of the power system. Preliminary results are discussed in [6],[7].

This project quantifies the system cost of the uncertainty of wind power generation in terms of the change in production cost between the dispatch using an hour-ahead wind forecast and the real-time dispatch using actual wind generation. The modeling encompasses time series data of power generation from a wind farm, a linear regression model for hour ahead forecast, Monte Carlo simulation to capture the uncertainty of the real-time wind power generation. An optimal power flow is used to represent the transmission network and the role of the network in constraining the system response to changes from the forecast to the actual dispatch.

Section II presents the data used for the system simulations, including the development of the time series data for wind power generation from a hypothetical wind farm in Nantucket Sound, MA, and the use of the 39 bus IEEE test system. Section III presents the method used to represent uncertainty in the wind power generation, including a linear regression hour-ahead forecasting model, the development of the distribution of forecast errors and the Monte Carlo simulation using the distribution of forecast errors. Section IV presents results from simulating the 39 bus system with the wind farm, under different scenarios of load level and generator ramp rate. Finally, the implication of the results and the next steps in the project are presented in Section V.

II. Wind Farm and Power Network Models

A significant cost associated with wind generation forecast uncertainty results from the need for additional resources at real-time dispatch, when forecast errors leave the system either with excess or insufficient generation to meet load. The cost to the system of adapting to these forecast errors is constrained by the current state of the other generators on the system, and potential transmission constraints on the network. Therefore, the method presented here requires a simulated wind farm and power system network.

A. The Simulated Wind Farm

The power generation from a wind farm is modeled using time series wind speed data that is translated to power output using a turbine power curve. For the modeling presented here, ten-minute wind speed data from Nantucket Sound, MA [8] is used in conjunction with the GE 2.5MW turbine power curve [9] to represent the output from a 550 MW wind farm. This hypothetical wind farm represents approximately 10% of the regional generating capacity. To capture the effect that geographic diversity has on decreasing the variability in wind power generation, the method presented in [10] was implemented. This algorithm involves adjusting the wind speed data from a single point with a moving block average to represent the wind speed across the wind farm. The turbine power curve is also adjusted to represent the effective aggregated power curve from the multiple turbines in the wind farm.

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The adjusted wind speed data is then translated to power output using the aggregated power curve. Figures 1, 2 and 3 show the original and adjusted wind speed data, power curve, and power output respectively, demonstrating the positive role of geographic diversity in decreasing the variability in wind power generation.

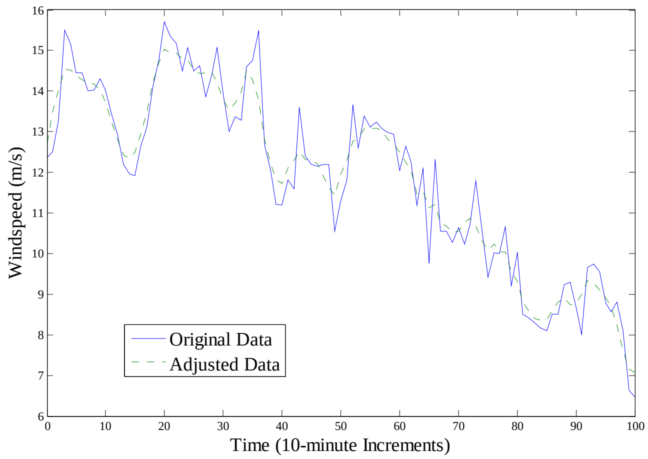

Figure 1. Wind speed data: original and adjusted for geographic diversity

As illustrated in Figure 1, the effect of adjusting this wind speed data for diversification causes a reduction in the variability of the wind speed time series.

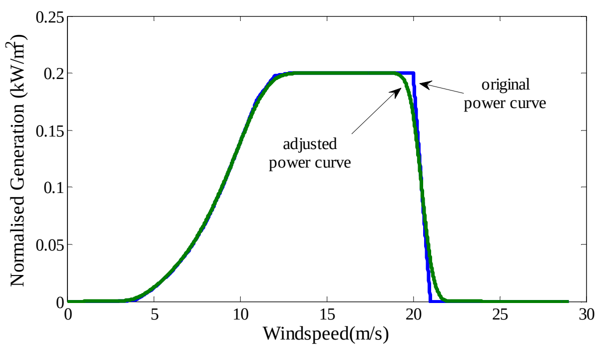

Figure 2. Original and aggregated GE 2.5MW power curve

It is shown in Figure 2 that the resulting power curve has a slightly smoother transition at the cut out speed of the turbine. This represents the spatial diversity of the wind across the area of the wind farm.

The final result of this diversification is summarized in Figure 3. This figure shows the wind power output from a theoretical wind farm using the original windspeed data with the theoretical turbine power curve, as well as the adjusted wind speeds with the power curve (shown in Figure 2) representing a small wind farm.

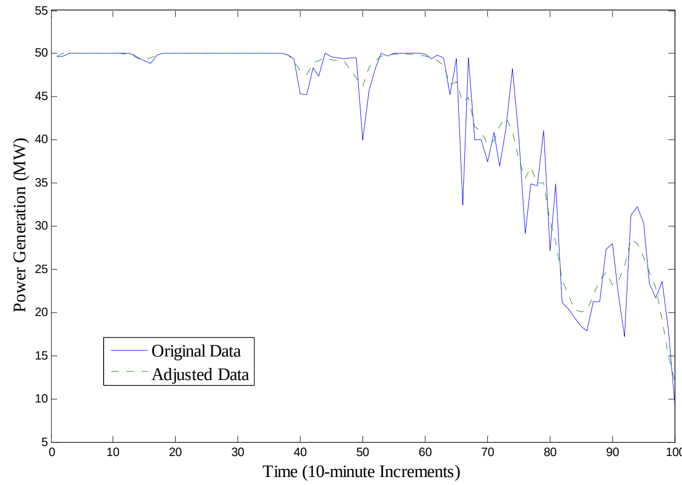

Figure 3. Wind farm power output: Original and Adjusted

B. The Transmission Network

The transmission system is represented with the 39 bus test system, loosely based upon the ISOne power grid. Figure 4 shows the 39 bus test system, in which the bottom right star represents the location of the hypothetical wind farm modeled in this project. To model the impact of wind power in this test system, one generator is replaced with the wind generation. The method used to model the uncertainty associated with the wind power output is discussed below in section III.

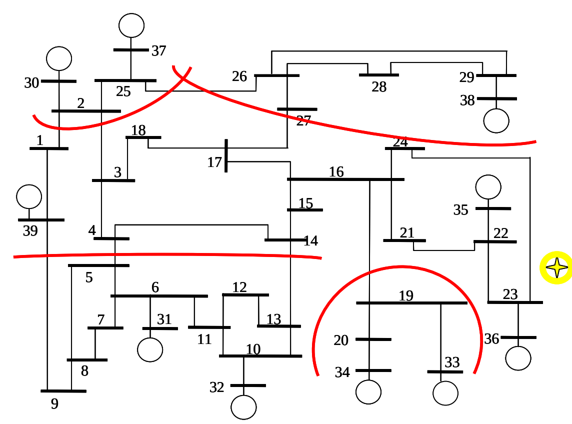

Figure 4. The 39 bus test system, with wind farm shown as lower right star

III. Assessing the Impact of Uncertainty with the Optimal Power Flow

The electric power system is modeled with the optimal power flow in Matpower [11], using the 39 bus test system. Twelve scenarios are simulated, with differences between the scenarios arising from changes to the regional load level and constraints on the level that other generators can ramp their output up or down in response to the uncertain wind farm output. Specifically, a base case dispatch is established for each scenario. Forecast errors are implemented in a Monte Carlo Simulation (MCS) framework.

A. Wind Farm Output Forecast Errors

Beginning with one year of ten-minute wind speed data, an hour ahead forecast is created using a linear regression model of the complete dataset. Each hour's forecast is then converted to a hypothetical wind farm output and compared to the actual power output, both determined using the method discussed above in section II. From this comparison, a distribution of forecast errors is determined, with the results shown in Figure 5.

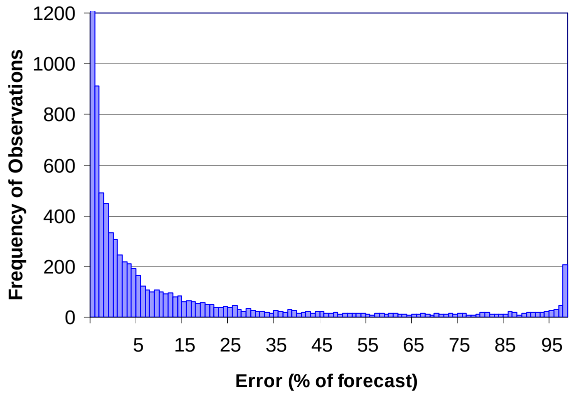

Figure 5. Distribution of hour-ahead power output forecast errors

B. A Monte Carlo Simulation Framework

The cost associated with forecast errors is stochastic in that the magnitude of the error is variable, and the costs resulting will depend on the stochastic error, as well as the system load, capacity and ramp rates of the other generators on the system. In order to capture this uncertainty, the OPF calculation is implemented in an MCS framework.

In this approach, the hour ahead dispatch is determined from the wind forecast. A forecast error realization is obtained by sampling the distribution described in Section III-A. With the corrected forecast, the OPF is used to recalculate the dispatch. The new dispatch is constrained by the ramp limits of the other generators on the system, and their current output based on the initial hour ahead dispatch. The initial set of twelve scenarios are defined by changing the regional load level and the ramp rates of the non-wind generators. For regional load, the real power demand at each bus in the test system is increased 5%, 10% or 15%. For all the generators in the test system other than the wind farm, the ramp rates of the generators are constrained to 2.5% and 5% of the total installed capacity of each generator. In the opf input file, this is achieved by setting the dispatch point of each generator to its dispatch in the base case simulation, and setting the minimum and maximum power levels to 2.5% or 5% below and above this point.

IV. Results

The objective of the modeling in this project is to quantify the system costs of the uncertainty in wind generation forecasts. Figure 6 shows the results of the simulations, with system costs represented in terms of total production cost, in $/hr, of the power system meeting regional load.

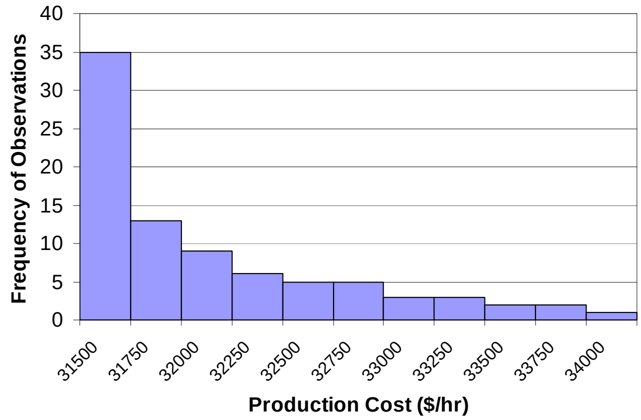

Figure 6. Increase in Production Cost Resulting from Wind Speed Forecast Errors

These results show that the production cost increases between 2.5% and 11% for the different scenarios, depending upon load level and ramp capability of the other generators. However, in one third of the cases, the additional cost of this uncertainty is within 2.5% of the base cost. When the ramp rate is constrained to 1% of the installed capacity overall, an additional effect of the wind power uncertainty is observed – that of infeasible OPF solutions up to 38% of the time. This indicates that that under the specified conditions the system would be unable to meet load. Such results are not an indication of wind power increasing the likelihood of power system blackouts, but rather an indication of an overly constrained system and the need for load response as system resources become more constrained.

V. Conclusions

The power system simulations presented above capture some of the system costs of uncertainty in wind power forecasts, specifically focused on real power generation and demand. The modeling simulates the behavior of a transmission network that includes a wind farm, using an OPF. The uncertainty in the forecast error is captured through the use of a MCS framework. The system costs of wind power uncertainty are represented as changes to the $/hr cost of producing and transmitting power to the regional load centers. These costs are shown to increase between 2.5% and 11% with the initial set of scenarios analyzed for this project.

The next phases for the modeling include creating different forecasting models and subsequent distributions of forecast errors conditioned upon wind power output levels. Multiple wind farms will be modeled to increase the geographic diversity while also highlighting the possibility of the transmission network in exacerbating the uncertainty of wind power output. In defining the scenarios, the time series data for regional load and wind speed will be correlated. Finally, ramp rates for individual generators will be defined according to different technology capabilities.

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