Wind Integration Study

Introduction

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Preface

The wind study performed by EnerNex Corporation on behalf of Xcel Energy and the Minnesota Department of Commerce is a significant advance in the science of understanding the impacts of the variability of wind power on power system operation in the Midwest. The application of sophisticated, science-based atmospheric models to accurately characterize the variability of Midwest wind generation is a vast improvement over previous methods.

This introduction to the wind integration study provides an overview of the study and its findings. For a more detailed examination of the study methodology and results, the reader is referred to the two-volume report found on the Minnesota Department of Commerce website.

Volume 1: Wind Integration Study - Final Report

Volume 2: Characterization of the Wind Resource in the Upper Midwest

Introduction

Reliable power system operation requires a precise balance between load and generation. That means that power production must be increased simultaneously with increases in customer demand and reduced simultaneously with decreases in customer demand.

Wind generation is variable, but how this variation combines with variations in load is a critical factor in determining the impacts.   As the output of wind farms increases or decreases relative to the system load, the output of other sources of generation, such as coal or nuclear plants, must be adjusted.

Wind plants are becoming large enough to have measurable impact on system reliability and operating cost.

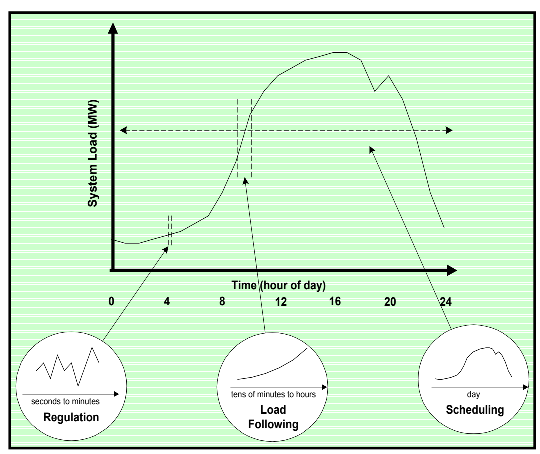
The purpose of this study was to evaluate the impacts on reliability and operating costs of 1500 megawatts of wind generation capacity on the Xcel Energy system with a projected 10,000 megawatts of peak customer load in the year 2010.

Overview of Utility System Operations

The Xcel Energy power system consists of a network of power plants and interconnecting power lines designed to deliver the output of the power plants, or generation, to customer loads. Within this system, generation and load must be matched on a real time basis. This is accomplished by system operators who constantly monitor system load and adjust the generation to changes in customer demand.

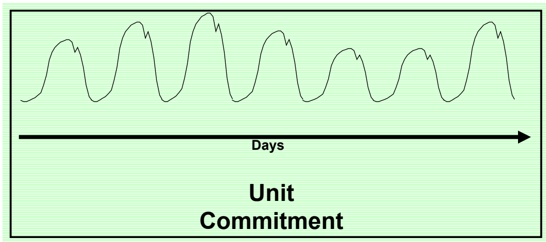
There are four time scales of interest in the monitoring operation of the power system: 1) regulation, 2) load following, 3) scheduling, and 4) unit commitment

Regulation is the process of maintaining system stability by adjusting certain generating units in response to fast fluctuations in the total system load. These fluctuations typically occur over a period of a few seconds to several minutes and are caused by customer actions as minor as turning on an air conditioning unit or as major as firing up a large industrial arc furnace.



Load following is the process of ramping generation up or down in response to daily load patterns. These patterns are typically predictable as load comes up in the morning and comes down in the evening.

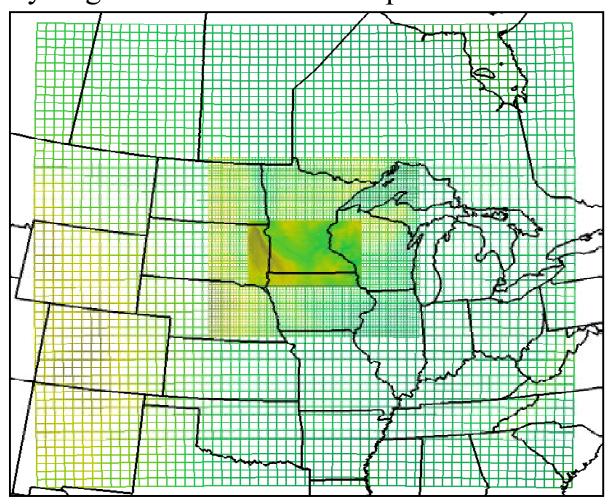
Scheduling is the practice of scheduling power plants for the next day based on short-term load forecasts and equipment availability.



Unit commitment is the practice of committing generation units several days in advance based on longer-term load forecasts, planned plant maintenance and other variables.

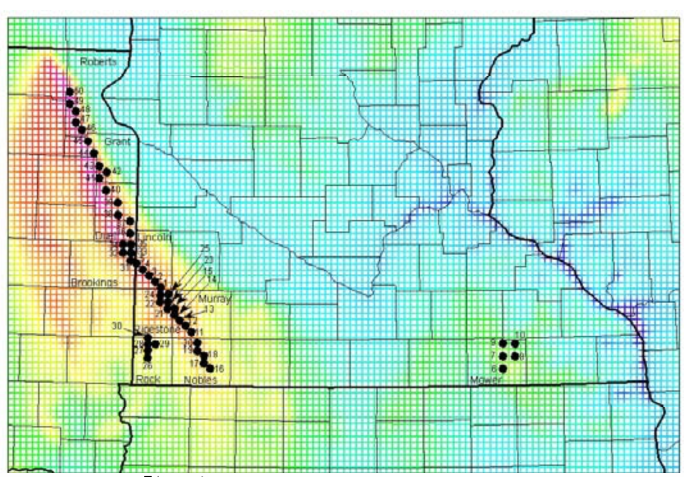
Wind Resource Characterization

Predicting how all the wind plants in the 1500-megawatt scenario appear in the aggregate to the Xcel system operators and planners is a critical aspect of the study. The total amount of wind generation will likely consist of many large and small facilities spread out over a large land area, with individual facilities separated by tens of miles over approximately two hundred miles.



The National Center for Environmental Prediction collects data and runs models to provide standard weather forecasts. A weather research company, WindLogics, archives that data. Sophisticated simulations utilized that archived weather data to "recreate" the weather for the years 2000, 2002, and 2003.

The figure on the right shows the grid used with the numerical model to simulate the actual meteorology occurring over the upper Midwest. The simulation featured three grids with two internal, nested grids of successively higher resolution. On the innermost grid, specific points that were either co-located with existing wind plants or likely prospects for future development were identified along Buffalo Ridge and in Mower county. See illustration on the left.



Wind speed data along with other key atmospheric variables from these selected points were saved at ten-minute intervals as the simulation progressed through three years of weather modeling. The results of the simulations were then applied to another set of data archived by WindLogics from the National Center for Atmospheric Research. This database represents 55 years of atmospheric data. This process "normalizes" the model data to better represent the historic character of the wind resource for the area of interest over 55 years.

The wind speed data was converted to wind generation data by applying power curves for existing and prospective commercial wind turbines at each of the selected locations.

Xcel System Model

A model of the projected Xcel system profile for 2010 was developed. The model included historical system load and plant performance data as well as projected load growth and generator additions. The geographic distribution of the individual wind plants comprising the 1500-megawatt scenario is depicted in the following table.

County	Nameplate Capacity
Lincoln	350 MW
Pipestone	250 MW
Nobles	250 MW
Murray	150 MW
Rock	50 MW
Mower	150 MW
Brookings (SD)	100 MW
Deuel (SD)	100 MW
Grant (SD)	50 MW
Roberts (SD)	50 MW
Total	**1,500 MW**

The wind generation scenario was derived from the numerical weather model data discussed in the previous section on Wind Resource Characterization. However, the 10-minute resolution of the WindLogic dataset is inadequate for fully characterizing the impacts of the 1500 megawatts of wind generation on the short time period of regulation control.

To estimate the short time period characteristics of the wind generation in the study scenario, one-second resolution monitoring data from the National Renewable Energy Laboratory for the Buffalo Ridge substation and Lake Benton II wind plant was included in the model.

The resulting model was then used to evaluate reliability impacts and operating cost impacts described in the following sections.

Reliability Impacts

The reliability impact of 1500 megawatts of wind power on the Xcel system was determined utilizing a concept called effective load carrying capability (ELCC). ELCC is a measure of the capacity value of any generator. This method of measuring reliability has been applied to traditional power plants for many years. However, it is a fairly new concept when applied to wind.

Each power plant contributes to system reliability based on its specific characteristics. Since no power plant is 100% reliable, this method takes unplanned outages into account. For example, a base load coal plant could experience an unplanned outage at any time. However, since the unplanned outage has a low probability of occurring, the ELCC for the coal plant is relatively high. Since the variability of the wind resource adds a level of uncertainty in addition to its turbine outage probability, its ELCC is expected to be lower.

This study used a reliability simulation software model to calculate the ELCC of wind in the study area. Three years of wind generation data was analyzed. That data was mapped on the proposed Xcel 2010 system and hourly generation and loads were calculated for three years. The results show that the ELCC of the system improves by 400 megawatts, or 27% of nameplate capacity, with the addition of 1500 megawatts of wind resource.

Thus, the addition of 1500 megawatts of wind turbine capacity on the Xcel system contributes 400 megawatts of reliability to the projected Xcel system peak load of 10,000 megawatts in the year 2010.

Operating Cost Impacts

The operating costs to serve the load are affected by the plans and procedures necessary to accommodate the variability of the wind generation and to maintain the reliability of the power system. These costs are called integration costs. The system is impacted over the time frames ranging from a few seconds to several days and are defined as regulation, load following, scheduling, and unit commitment. Refer to the previous section, Overview of Utility System Operations, for a graphic depiction of these time frames.

Regulation: The operating cost impact of wind on the ability to react to short term fluctuations in customer demand over a period of a few seconds to several minutes.

The study determined that the variability of 1500 megawatts of electricity on the Xcel system requires the reservation of an additional 7.8 megawatts of reserve capacity. A reserve capacity of 7.8 megawatts times the number of hours in a year would generate 68,328-megawatt hours of energy per year.

The cost of this incremental regulating requirement can be estimated by calculating the opportunity cost of the additional reserve capacity. The opportunity cost is computed as the revenue, less production cost, for energy that cannot be sold from the regulating capacity of 7.8 megawatts of electricity, or the cost of 68,328-megawatt hours of energy per year.

Xcel Energy currently employs large fossil fuel units for regulation so the production cost is approximately $10 per megawatt hour. The study assumed that this energy could be sold at $25 per megawatt hour, generating an opportunity cost of $15 per megawatt hour. Thus, the opportunity cost is just over $1,000,000 per year.

At an average capacity factor of 35%, the annual production from the 1500 megawatts of wind generation is 4.5 million-megawatt hours per year. One million dollars of opportunity cost spread over 4.5 million-megawatt hours produces a regulation cost, due to the variability of wind, of $0.23 per megawatt hour.

Load following: The fact that the wind resource sometimes fluctuates contrary to system load fluctuations creates an operating cost impact. For example, the wind may drop off as load picks up in the morning or the wind may pick up as load drops off in the evening.

It was determined through statistical analysis that the load exhibits significantly more variability than does wind generation over these short time frames. Therefore, the increase in operating cost due to load following is negligible. Thus, no monetary value was assigned.

Scheduling & Unit Commitment: Because wind plant output is not predictable and/or the wind forecast is not accurate, there is an operating cost impact for scheduling and committing units for the next day and several days ahead.

Because many generating units cannot be stopped and started at will, operating plans are developed to look at the expected demand over the coming days and commit generating units to meet this demand at the lowest possible production cost. These plans are developed by system schedulers, utilizing unit commitment and scheduling software.

The basis for the following simulations was a two-year history of hourly system load data and hourly wind generation data

The first step in this analysis was to build a reference system using the unit commitment and scheduling program. On the reference system it was assumed that the daily energy from wind generation was known precisely, and that it was delivered in equal amounts over the 24 hours of the day. These model runs produced a reference system production cost.

In the second step, projected load and wind generation forecasts were assumed. The program determined the lowest cost way to meet the load and accommodate the wind generation as it was forecast to be delivered. The forecast wind generation was then replaced by the actual wind generation to determine the lowest cost way to meet the load and accommodate the wind generation as it actually happened. The difference between the costs utilizing forecasted wind data and the costs utilizing actual wind data is the actual system production cost.

The difference between the reference system production cost from the first step and the actual system production cost from the second step is the scheduling and unit commitment integration cost due to the variability of wind.

This cost was determined to be $4.37 per megawatt hour of wind generation.

Summary

As we see greater levels of wind penetration into the Midwest power system, the question arises as to how much wind can be reliably integrated and the cost of absorbing that amount of wind.

The study concludes that 1500 megawatts of wind energy can be reliably integrated on the Xcel system. The study also concludes that 1500 megawatts of wind contributes 400 megawatts of effective load carrying capability, or 400 megawatts of reliability.

The analysis conducted in this study indicates the costs of integrating 1500 megawatts of wind generation into the Xcel control area in 2010 are no higher than $4.60 per megawatt hour of wind generation. This represents a wind penetration level of 15% on a projected peak load system of 10,000 megawatts.

The total costs include $0.23 per megawatt hour as the opportunity cost associated with an increase of 7.8-megawatts of reserve capacity to satisfy the regulation requirement; and $4.37 per megawatt hour of wind generation attributable to unit commitment and scheduling costs. The increase in production cost due to load following was determined by statistical analysis of the data to be negligible.

The study concludes that these costs are conservative, or worst case costs for a number of reasons. First of all, the emergence of wholesale energy markets could provide a less costly alternative to using internal resources to compensate for the variability of wind. Secondly, these costs are based on current state of the art forecasting and scheduling and unit commitment techniques. These techniques should improve as experience with wind integrating grows and the integration cost of wind should decrease for this level of wind penetration.

The production costs due to the variability of wind are unique to the characteristics of the system being studied and these findings cannot be assumed to apply to non-Xcel control areas or the aggregate of all control areas in Minnesota.

The study did not examine wind penetration beyond the 15% penetration level and did not indicate at which penetration level wind may become non-cost effective.