Atmospheric Pressure

Weather, Wind Forecasting, and Energy Market Operations

THE MODERN ELECTRIC POWER SYSTEM constitutes a fascinating challenge in delivering reliable and inexpensive power using uncertain components in an increasingly complex world. While the components of the power system have always been uncertain and variable to some degree, the addition of wind and solar energy is increasing the need to directly manage these attributes in more sophisticated ways. Indeed, the growth of wind energy has served as a catalyst that is forcing us to develop the next generation of tools and practices for continued efficient and reliable system operations.

Wind is the fuel source for wind power plants, and because of the variability and complexity of the weather that creates the wind, wind power plants

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show variability and uncertainty in the instantaneous power that they deliver to the grid. The impacts of variability and uncertainty can be reduced in many ways. These include larger balancing areas (BAs) that combine the output from geographically dispersed wind plants to provide a more smoothed and predictable aggregated power level and having a sufficiently flexible power system that can reliably use the wind power at close to real time. But prediction is still the critical tool for scheduling wind energy so that we can better manage the system.

The technical nature of weather and wind power forecasting has been covered in past articles (see "For Further Reading"), so we'll discuss such things here only briefly. This article focuses on the latest trends and enhancements emerging in system operations as wind penetrations grow. We discuss technical improvements, current and pending market changes for very high levels of variable generation, the value of forecasting improvements, and the collaborative work that may lead to improved forecasting. This is work at the cutting edge, gathering the latest examples that the authors believe to be of special interest, and we expect this area to remain vibrant and dynamic for many years to come.

How Weather and Wind Power Forecasting Works

National weather services, including the National Oceanic and Atmospheric Administration (NOAA) in the United States, gather weather observations and provide a variety of different weather forecasts. Weather observations are obtained from many sources and many types of instruments: weather stations at airports and other locations, radar systems, aircraft, satellites, and more. Many observations are shared with other weather services around the world, creating a global snapshot of current weather conditions (see Figure 1). These observations are critical for creating weather forecasts.

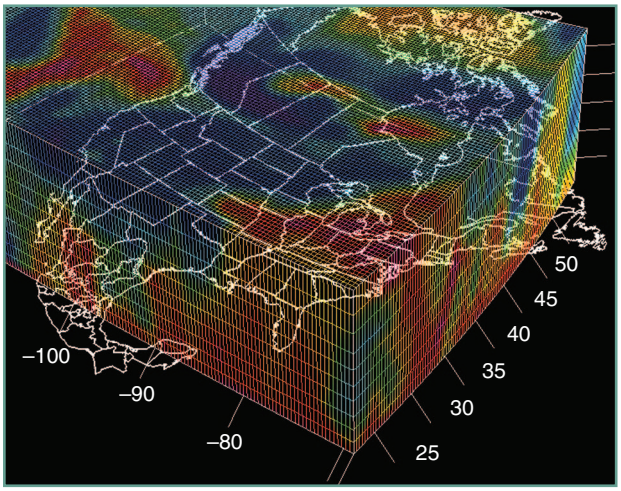

figure 1. Weather measurements from thousands of sources are assimilated, using the laws of physics to estimate values where measurements are not available, in order to create a representation of the entire atmosphere (courtesy of WindLogics Inc.).

Weather forecasting models use this snapshot as the starting point for predicting the weather changes for the coming hours and days. A numerical weather model is a computer simulation of the atmosphere and the physical processes that influence it. The various physical properties are represented or approximated by mathematical formulas that are implemented as computer programs, and the system of programs is run on fast computers to simulate the future state of the atmosphere. The quality of the results depends on both the quality of the starting point (current knowledge of the state of the atmosphere) and the fidelity of the simulation (how well the physical interactions are understood and represented).

Given the complexity and interactions of wind turbines with each other and with the localized terrain, a simple conversion from forecast wind speed variables to wind turbine power output does not provide a very good wind plant power forecast. Additional work is required to produce high-quality wind power forecasts, often using sophisticated combinations of statistical, learning system, or physical modeling techniques. Various companies and research groups are active in the areas of creating, supporting, and using optimized wind power forecasts. As shown in Figure 2, the methods for developing and using wind power forecasts are already quite sophisticated.

Weather forecasts and wind power forecasts are not perfect, however, and many opportunities for improvement remain. Fortunately, studies have shown that forecasts do not need to be perfect to be very useful and valuable. Winds do not change instantly, and changes are smoothed by the size of wind turbines and wind plants, so changes from minute to minute are manageable. Forecasts perform reasonably well for several days into the future, and as we will describe later, fundamental improvements in weather observations and models will provide ongoing incremental improvements in wind power forecast quality.

How the forecasts are used in our tools, operations, and markets is also very important. The probabilistic nature of demand and generation must increasingly be reflected in our practices. The intrinsic nature of various fuel sources and generator types must be accommodated in fair and logical ways to maximize the value and robustness of our increasingly diverse systems. Ongoing improvements in weather forecasting and the forecasting of variable generation such as wind and solar power that are influenced by the weather will play a key role in the future of our power system.

Data Requirements for Wind Forecasting

The previous section highlighted the value of data to weather forecasting in general. The amount of data needed from the wind plant itself is quite a separate issue. Multiple wind forecasting vendors have demonstrated impressive results from tools that require the power data but require little (if any)

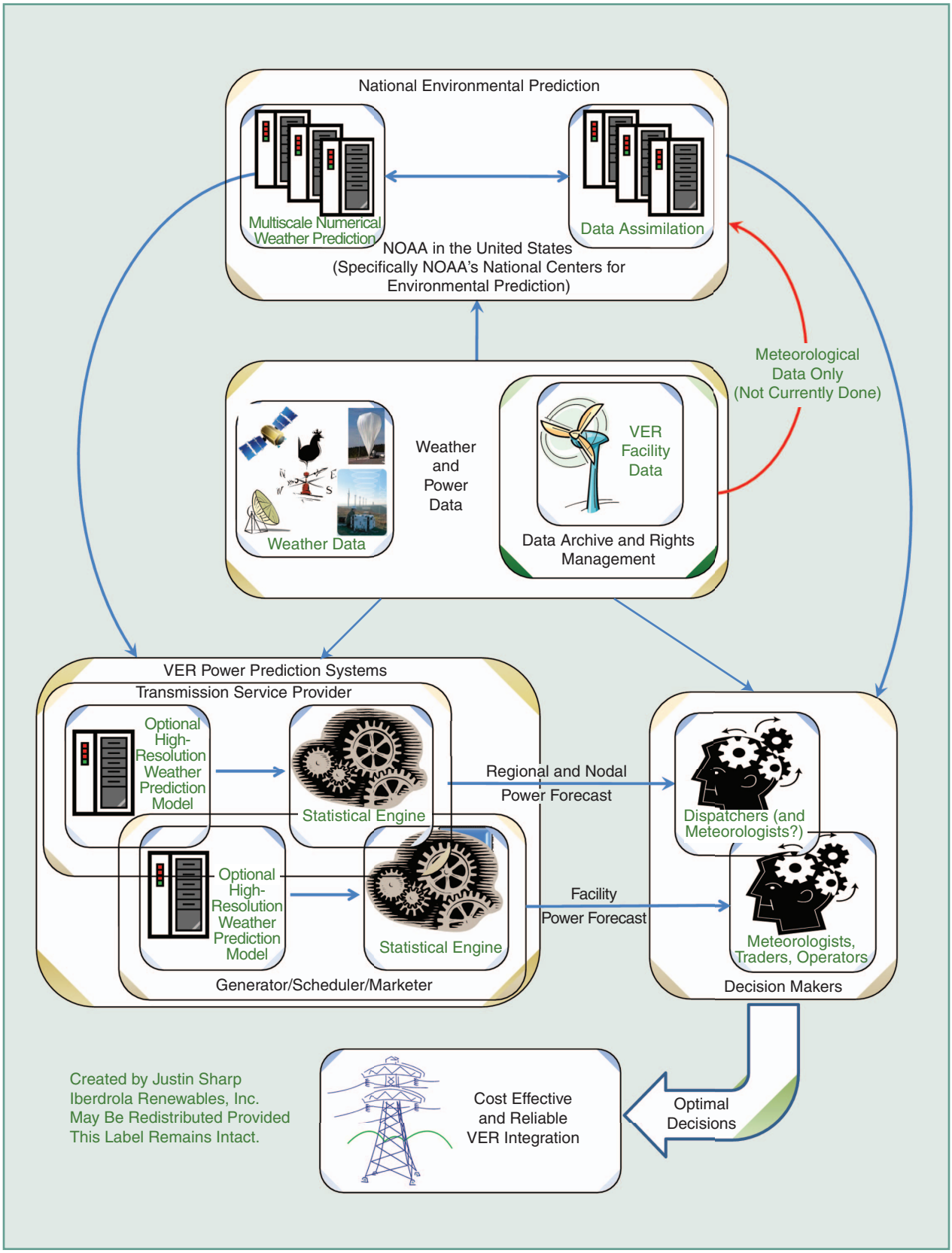

figure 2. Schematic illustration of the energy forecasting process for wind, a variable energy resource (VER), showing how observational data play a central role and how environmental predictions from national centers are the foundation of all power forecasts (courtesy of Iberdrola Renewables).

meteorological data from the wind plant. So what is the correct and reasonable balance when it comes to wind plant–specific data requirements?

Wind energy forecasts can be produced with no real-time data whatsoever. Geographic location can be approximated, wind power plant size is available through public sources, and a simple power curve can be approximated. Extract a wind speed from a publicly available numeric weather prediction model, and one has a crude forecasting system. Such models are cheap and simple but contain many approximation errors.

Having more data means getting better forecasts, but there are diminishing returns as the data become more granular and are obtained closer to real time. The infrastructure necessary to acquire large amounts of data in real time is expensive and difficult to maintain, and while the current power output level of the wind power plant is an excellent predictor of what it will be a few minutes into the future, weather variables are much more problematic. Forecasting systems that make use of great volumes of data are cumbersome and complex, and the cost-effectiveness of such data-intensive approaches must be weighed against that of the results from simpler methods.

Some basic data will greatly improve a wind energy forecast. Basic static data necessary for a good forecast include the geographic center of the wind power plant (latitude and longitude) and hub height. The basic dynamic data necessary are measures of the metered power output of the power plant (usually at five- or ten-minute intervals). This can be implemented through basic technology; a process that integrates the energy management system (EMS) output and makes it available to the organization creating the wind power forecast is generally sufficient. In addition, historic output lets a forecaster generate an empirical relationship between forecast wind speeds and output. If historical data are not available, a manufacturer's power curve or other approximation for power conversion can be used until enough data are gathered to generate an empirical relationship.

The next layer of data value consists of current wind power plant availability (the number of wind turbines available to generate right now) and forecast availability (the number of wind turbines expected to be available tomorrow). The former value lets a forecaster fine-tune the power conversion to account for lost generation due to maintenance. The latter can be blended into a wind energy production forecast to derate output according to a planned maintenance schedule. The challenge is developing a convenient interface wind power plant operators can use to submit their maintenance schedules and educating them about the importance of using it.

Curtailment instructions from the system operator should also be incorporated into the data, both for correcting historical data and for the operational wind power forecast. If the forecast is not aware of curtailments due to transmission limitations or market instructions, the forecast will obviously be unable to reflect such power differences. Similarly, if curtailment is not identified in historical power data, the data may be detrimental to the forecaster.

Wind speed and direction data at the wind power plants should be considered after power, availability, and curtailment information, although the value of this data will depend on the wind power forecast methods adopted. Some forecast providers insist on lots of wind speed data, while others use methods that optimize directly to power and do not require wind speed data to generate a good power forecast. The quality of the power forecast is what matters, of course, so forecast end users must carefully weigh the costs of data requirements against the provided benefits.

Wind speed data can be collected from an on-site meteorological tower. Alternatively, the average of the nacelle wind speeds may provide a more accurate picture of wind speeds across the wind power plant, although nacelle wind speed is influenced by the turbulence from the turbine blades. The forecast provider will generally suggest which is most useful, depending on its forecasting methods.

Finally, full turbine-level data (wind speed, temperature, and power) and perhaps additional off-site meteorological data (temperature, wind speed, wind direction, humidity, and air pressure) make up the ultimate level of granularity that could be considered. Intuitively, it would seem that off-site data could be used in the short-term time horizon to predict large changes in output—so-called ramp forecasts. To date, research seems to show that the additional turbine-level and off-site meteorological data have mixed or marginal value in improving forecast performance, and a clearer understanding of the cost-benefit value is needed. Research continues in this area, in particular with the U.S. Department of Energy (DOE) and NOAA effort to assimilate large amounts of additional meteorological data with the goal of improving short-term forecasts for the wind industry (this initiative will be discussed below).

Ramp Forecasting and Decision Support

More recently, industry members and forecast providers have begun to investigate the need for forecasts created specifically to detect significant ramps in variable generation power output. Many of the standard forecast products currently in operation were designed using more conventional optimization functions, such as minimizing root-mean-square error (RMSE). Minimizing average error may have a tendency to "wash out" the ramps (i.e., may fail to show the duration and magnitude of a ramp event). For grid operators, extreme events are often of the greatest importance as they may affect their ability to match energy demand and supply. A natural step forward is therefore to design modified forecast products that will specifically address these periods when the risk to reliable grid operation is potentially the highest.

When the value of ramp forecasting is discussed, the definition of a ramp event is extremely important. Whether

a ramp is a rare or a common event and how accurately the forecast matches ramp events are strongly influenced by the choice of ramp criteria. It is common to characterize a ramp as a large change in wind power production over a short time interval (e.g., a 20% power increase within 30 minutes, with the percentage being relative to the total size of the wind power plant). Figure 3 illustrates how different ramp definitions can lead to different numbers of events. For predictions for regional aggregates of U.S. wind power plants, the number of ramp events can easily vary between 50 and 1,000 events per year depending on what is considered to be a "ramp event."

There are a number of approaches that can be taken to implement forecasts aimed at detecting ramping. A simple method would be to modify a more common deterministic forecasting product to use an optimization function that penalizes the forecast error more heavily during ramping intervals. This would result in ramping periods being given higher priority during the tuning process and provide grid operators with more accurate information during these types of events. This type of product may also lend itself well to probabilistic forecasting tools through which an operator would be provided with information regarding the likelihood of a ramp event occurring within some short time frame. The manner in which probabilistic information can be used by operators in a meaningful way is in itself a complex topic.

The creation of the forecast is only one step in providing system operators with information that is both clear and actionable. The design of the user interface should be driven by the manner in which the forecast will be used. For example, a ramp forecast could provide additional insight when determining the need to commit or decommit additional generation resources for the next six hours. Additionally, a ramp forecast would help operators determine whether or not to deploy system reserves in the next 30 min. Different uses may require different user interfaces.

Another important factor in the development of the interface is to keep the presentation simple. This can be achieved by presenting graphical information for specific time frames and by aggregating data on a regional or systemwide basis. Figure 4, taken from the ramp forecast tool in production at the Electric Reliability Council of Texas (ERCOT), shows an example of such an interface. The displays provide a view of what is expected from the variable generation resources along with confidence bands around the forecast.

Although a ramp forecast product will provide additional situational awareness, in many cases it will be most effective when used along with other types of forecast products (i.e., a forecast tuned to minimize average error) or integrated into a unified forecast product. For example, ramp events and their uncertainty in timing can be visualized in addition to the standard optimized forecast as shown in Figure 5. The benefit of such an approach is that predicted gradients due to up- or down-ramps are clearly visible to the operator.

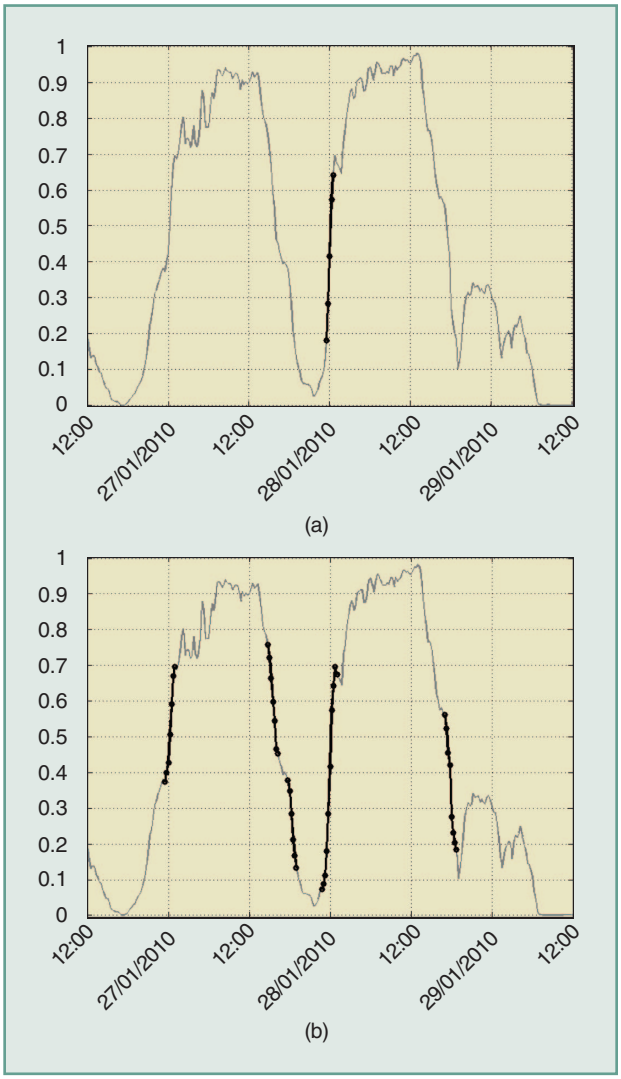

figure 3. A plot of normalized power output versus time showing wind ramps. In (a), with a ramp definition of a 20% power change within 30 min (marked by the thick dotted line), only one strong ramp event was detected in the shown period. In (b), with a ramp definition of a 20% power change within 60 min, five ramp events were detected in the same period.

Benefits of System Size, Flexibility, and Ancillary Services

In general, larger markets are more adept at handling higher wind penetration rates based on a number of general principles:

- ✔ Larger markets are typically more geographically diverse. Geographical diversity of wind resources reduces the aggregated short-term fluctuations and forecast errors in wind power.
- ✔ Larger markets typically use a centralized wind power forecast (or several of them) and security-constrained unit commitment and economic dispatch tools.

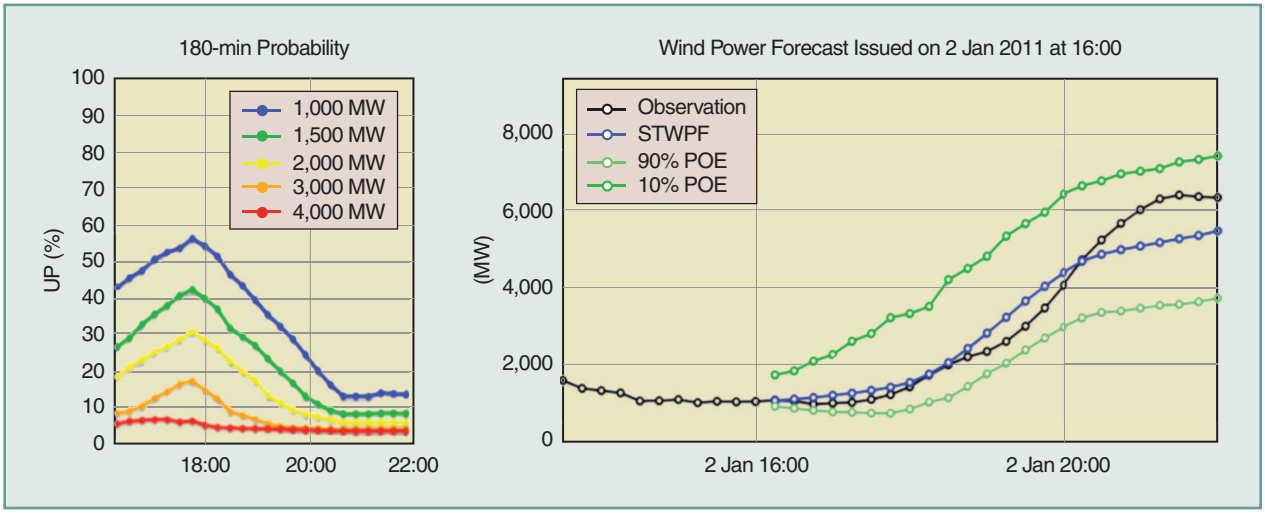

figure 4. Displays of ramp event probabilities and forecast power output at ERCOT.

Integrating the wind power forecast into the dispatch analysis lets the market proactively schedule resources to address changes in wind power output. Economically dispatching a larger fleet of generation at five-minute intervals can reduce the amount of intrahour regulation that is required to maintain system control. Another benefit of an accurate wind power forecast is reducing the costs associated with over- or underscheduling intraday or day-ahead generation.

- ✔ Larger markets typically use a single, centralized BA. A single, large BA aggregates multiple wind plants, allowing random weather errors to cancel out and reducing overall variability. It also encompasses more resources with which to balance the wind and provides efficient market operations with transparent prices for dealing with energy and ancillary service needs.
- ✔ Larger markets typically have an organized committee structure with task forces developed whose scope includes addressing planning, markets, operations, and reliability issues specific to a high market penetration of variable resources and recommending types of technologies, requirements, rules, or business changes that can be vetted by market participants.

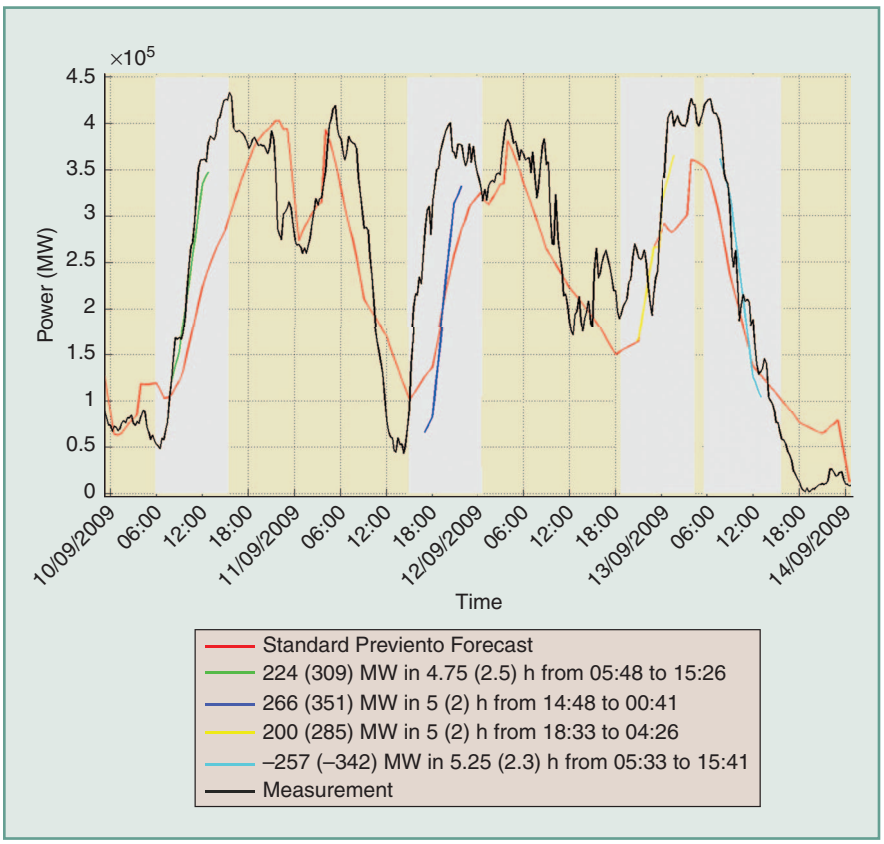

figure 5. Display of predicted ramp events (colored lines) in connection with the standard RMSE-tuned forecast (red line). The uncertainty of the ramp timing is indicated by the shaded regions. The black line shows the actual power generation. (Courtesy of Energy & Meteo Systems.)

As one example, these principles are being applied by the California Independent System Operator (CAISO), which expects to see very large increases in wind and solar energy by 2020 (see Figure 6). Given these expected changes to the generation mix, CAISO has conducted several detailed analyses

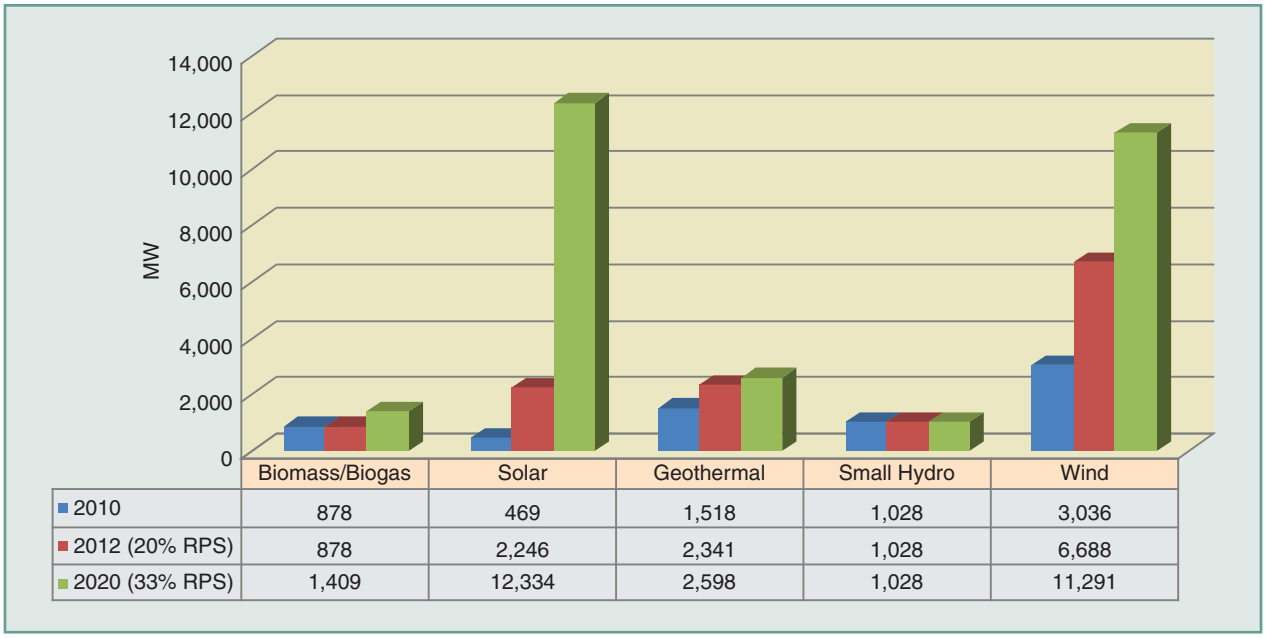

figure 6. California renewable resources expected in 2012 and 2020.

over the past several years to arrive at a better understanding of the operational and transmission requirements of wind integration and to evaluate the operational capabilities of the existing generation fleet.

These studies have revealed that it is important to have system flexibility to provide load following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than those currently experienced. The studies also showed that forecast uncertainty will increase the need for some resource capacity and ancillary services and potentially create an opportunity for new load- and ramp-following services in the future. While still being discussed with stakeholders, these challenges could require a combination of operational, market, and policy solutions, including bringing fast-responding storage and other flexible technologies into the ancillary service markets.

The CAISO studies also showed the likelihood of an increased occurrence and magnitude of *overgeneration*, a condition where there is more supply from nondispatchable resources than demand. To mitigate such conditions, system operators may increasingly require intermittent resources to be flexible and incorporate them as part of their dispatch systems. This is discussed in more detail in the next section.

In addition, CAISO and other balancing authorities throughout North America are participating in a field trial concerning area control error limits. The field trial is serving as a proof of concept for a draft NERC reliability standard, BAL-007, that would change how balancing authorities measure area control error (ACE) by allowing them greater flexibility when system frequency is stable. The results of the field trial have impacts on energy dispatched from regulation resources and may reduce the amount of regulation that is needed in the future.

In general, analysis by system operators is showing the need for greater fleet flexibility, including flexibility from the renewable resources themselves. By working with stakeholders to determine market rules and incentives that encourage participation, CAISO and other system operators are building greater system flexibility to meet the needs of future power systems with higher levels of variable generation.

Wind Dispatch and Control

The rapid growth of wind capacity across the world presents a new challenge for grid operators. With wind plants often interconnecting in concentrated clusters, current transmission networks are often incapable of delivering all the potential wind energy from the region. Additionally, in regions with sophisticated wholesale electricity markets, constraining conditions such as local transmission congestion can result in deflated (or even negative) market prices that reflect the local value of energy at a given time.

One technique to address the lack of available transmission, as well as the market impacts of too much wind generation at any given time, is to let wind plants be redispatched to lower output levels during periods when it is not economic or reliable for them to continue producing at full capability. To accomplish this, several ISOs have taken steps to integrate wind energy into their security-constrained economic dispatch (SCED), allowing them to redispatch wind plants to lower output levels according to current grid and market conditions.

In one example, the New York Independent System Operator (NYISO) has developed a program that integrates its real-time wind forecast into the real-time dispatch. NYISO uses its wind forecast to predict the output level at which a wind plant will be generating over the next five-minute

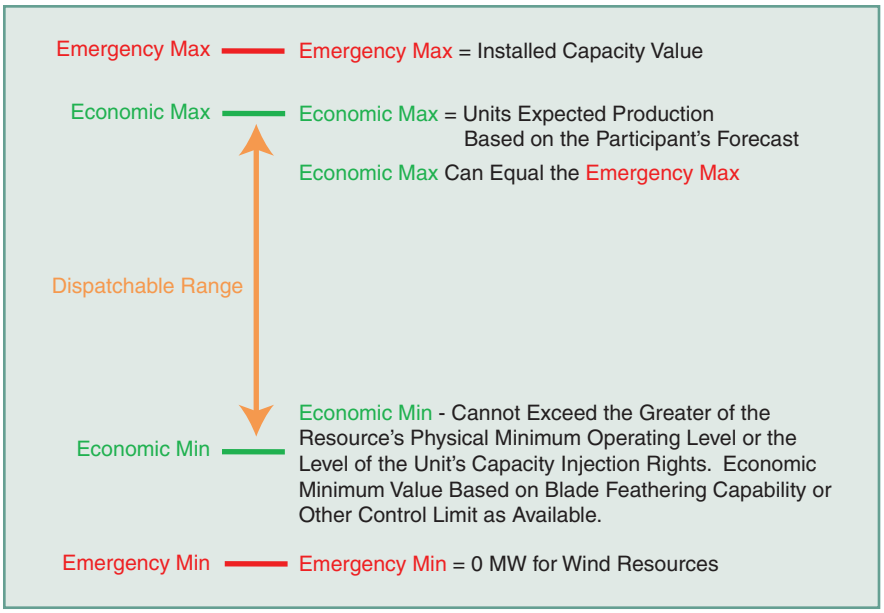

figure 7. Wind operating limits in PJM.

through 60-min time horizon, broken up into several time steps. At each time step, NYISO determines the output level at which the wind plant is economic to operate by using an economic offer curve supplied by the wind plant. If the wind plant is economic only at an output level that is lower than its forecast level, NYISO will send a redispatch signal to the wind plant, requiring the wind plant to reduce its output to the economic level. If the wind plant is economic at its full forecast output level, then the wind plant is permitted to operate at any output level. This dispatch evaluation occurs every five minutes.

The NYISO program lets wind plants indicate their economic willingness to produce energy and to be dispatched according to those instructions. In turn, NYISO is able to make more efficient dispatch decisions by including wind resources in the mix of resources available to address a system constraint. Note that the wind power plant is effectively required to reduce its output only during a system constraint and can otherwise deliver all its available energy.

Similarly, the PJM Interconnection (PJM) has taken several steps to enhance the grid operator's ability to manage wind resources. All generating resources are now able to submit negative economic offers, enabling wind resources to submit flexible offers that better reflect the price at which they will reduce output. Also, in order to ensure that resources do not force emergency procedures, generators must be able to adjust their output levels when operating in the range between the economic minimum and the maximum facility output (MFO) (see Figure 7). Resources may not submit an economic minimum in the real-time energy market that exceeds the greater of the resource's physical minimum operating level or the level of its capacity interconnection rights (CIRs). For wind plants, the CIRs are typically equal to 13% of the MFO.

PJM can request a wind generator to reduce its output if it is contributing to a transmission constraint. During constrained operations, generating resources will be redispatched in a cost-effective way based on their bid parameters. Curtailments will be based on unit offers and lowest US$/MW relief on the constraint (see Figure 8). Because of the variable nature of wind, PJM's unit dispatch system will only curtail (not increase) wind resources to control transmission constraints.

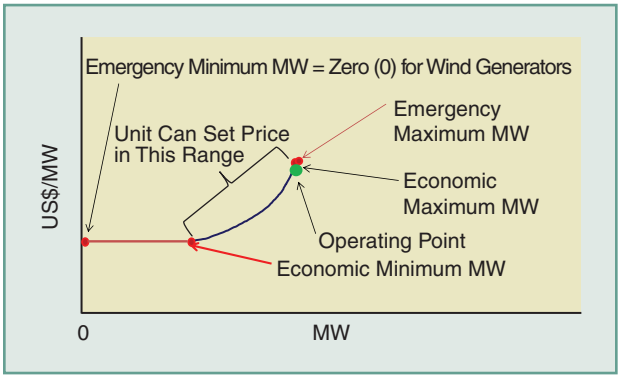

figure 8. A PJM constraint curtailment example. If wind is affecting the constraint and is the cost-effective solution, the dispatch will lower the desired wind base points toward the economic minimum.

Value of Wind Forecast Improvements

How much is improved wind power forecast accuracy worth? The value of forecasting improvements depends on many factors, including system conditions and actual operational practice. One factor is the type of forecasting improvement, e.g., whether errors are reduced on average, for extreme events, or for ramp events. The value also depends on the nature of the power system balancing the wind. A larger BA is generally more forgiving of forecast errors (because it aggregates wind power plants over a larger geographic area), has a wider variety of generation choices, and allows more flexibility to make changes based on the forecasting improvements than a smaller area. Finally, value depends on the sign of the error and the state of the system when the error occurs: wind exceeding its forecast may be a bigger concern when baseload units are already at minimum output, and a wind ramp might not be a major issue when gas combustion turbines that can readily back down are online.

Various case studies have examined the value of forecasting, and we report on three of them here: Western Electricity Coordinating Council (WECC), Alberta Electricity System Operator (AESO), and Xcel Energy.

WECC

The Western Wind and Solar Integration Study (WWSIS) analyzed operational impacts of up to 30% wind and 5% solar penetration in the WestConnect region of WECC. Hourly simulations of WECC operations modeled the production value from various levels of improvements in the day-ahead forecasts. Figure 9(a) shows a modest value for a 10% across-the-board improvement in forecast error, with approximately double the value for a 20% improvement. Figure 9(b) shows the further operational savings to be had as forecasts become perfect (100% improvement). Although a perfect forecast is not possible, this shows that the early, incremental improvements in forecast accuracy are the most valuable.

Roughly extrapolating these results to the entire U.S. power grid, based on the relative size of WECC versus the rest of the country, this analysis found that a 20% improvement in day-ahead wind forecasts resulted in US$260 million and US$975 million worth of annual savings in operating costs based on 14% and 24% wind energy penetration, respectively.

In addition, the analysis considered the impacts of improved forecasting on operating reserves and curtailment. With 24% wind energy penetration in WECC and no accompanying addition of operating reserves, some operating reserve shortfalls occurred. A 10% improvement in forecast errors reduced those shortfalls by about half, and a 20% improvement reduced the shortfalls by about two-thirds. Curtailment was also reduced by 4% for a 10% forecasting improvement and by 6% for a 20% improvement in forecast errors.

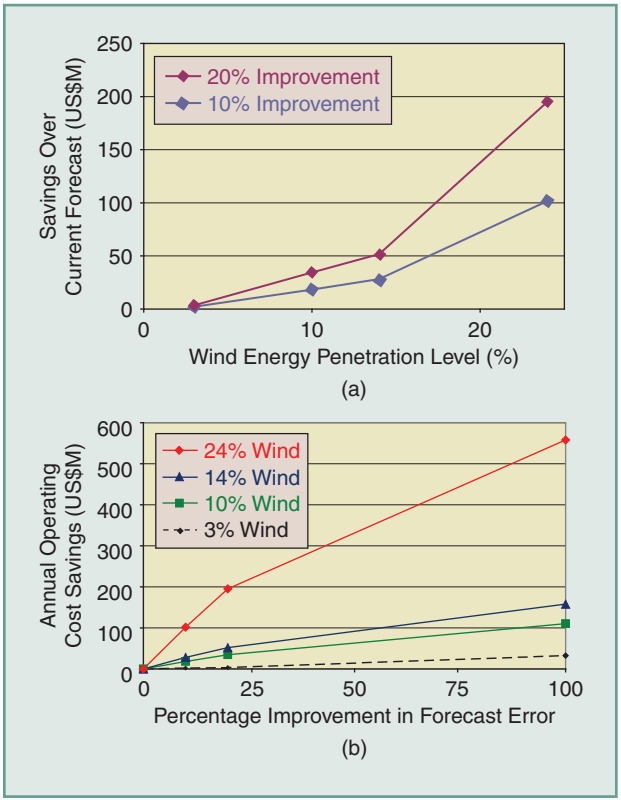

figure 9. (a) Average annual operating cost savings versus wind penetration for 10% and 20% improvements in wind forecasts. (b) Average annual operating cost savings versus wind forecast improvements shown for 3%, 10%, 14%, and 24% WECC wind energy penetrations.

AESO

AESO currently has 777 MW of wind power, representing a 6% penetration by capacity, but has another 6,800 MW of wind in the connection queue. In 2010, AESO experienced an average of two ramp events per week that were greater than 75 MW in a ten-minute time period. Two-thirds of these events were due to increasing wind energy production.

To deal with such up-ramp events, AESO is proposing to use wind power management (WPM) to limit the rate of wind power increases when the total amount of available wind energy cannot be accommodated. At 1,100 MW of wind capacity, WPM is expected to affect only 0.1% of the total wind energy production, but the need to use WPM will increase along with wind penetration levels. With 4,000 MW of wind capacity, simulations predict that WPM would affect around 3% of wind energy production. Improving short-term wind forecasting as wind capacity increases could reduce the amount of wind energy curtailed by WPM.

As part of its long-term wind integration plan, AESO is discussing various approaches for increasing the flexibility of its system, with options ranging from additional use of current reserves to the creation of a new, systemwide ramping ancillary service product. A more accurate wind forecast would contribute value to all options, although that value may accrue to different parties for different options. For example, a perfect wind power forecast would reduce the requirements to firm 500 MW of wind capacity to 50 MW for ramp-up service and 50 MW for ramp-down service at the 98% certainty level, as compared with about 240 MW required in both directions with a persistence forecast.

Reliability is a key mandate for AESO, and wind variability is one of many contributors to ACE. As wind penetration levels increase, the frequency and size of ACE events will rise. When wind ramp events are accurately forecasted, the energy market merit order can better match these ramps and reduce system imbalance. Table 1 provides the percentage of wind-related ACE events that would be abated by a perfect forecast, based on AESO simulations.

Xcel Energy

Xcel Energy integrates wind into its utility power systems, which operate in three regions and market structures: its Northern States Power–Minnesota (NSP-MN) company operates 1,561 MW of wind in the Midwest Independent

table 1. Percentage decrease in wind energy curtailed by AESO WPM and wind-related ACE events with a perfect forecast (as compared with using a simple persistence forecast).

Wind Capacity (MW)	1,100	1,575	1,700	2,500	4,000
% Decrease in Energy Curtailed by AESO WPM	80%	70%	70%	60%	50%
% Decrease in Wind-Related ACE Events	70%	70%	70%	60%	50%

Transmission System Operator (MISO) day-ahead market; Public Service Company of Colorado (PSCo) operates 1,484 MW of wind as a stand-alone balancing authority in the WECC region; and Southwestern Public Service Company (SPS) operates 896 MW of wind in the imbalance market structure of the Southwest Power Pool (SPP) system. Xcel has established a sophisticated forecasting system and conducted a "backcasting" analysis to examine the value of its improved forecasts. For NSP-MN, it found that the day-ahead mean absolute percentage errors (MAPE) were reduced from 15.7% to 12.2% from 2009 to 2010, resulting in US$2.5 million in savings. Similarly, it found US$3.1 million in savings in PSCo and US$400,000 in SPS.

It is significant that the value of the improvement in forecasting varied widely among the systems, even though the amount of wind energy was quite similar. When calculated on a "value per 1% improvement" basis, the values were US$830,000 for the PSCo system, US$722,000 for the NSP system, and US$175,000 for the SPP system. Why do they vary so much?

There are a number of reasons for this variation. Because NSP-MN operates within the large MISO market, with both day-ahead and five-minute markets, it has access to significant flexibility for handling forecasting errors. This reduces the cost impact of forecasting errors (and therefore reduces the perceived value of forecasting improvements). PSCo has the highest wind penetration and operates as a stand-alone BA with only hourly interchanges with neighbors to help deal with large forecast errors. It is a flexible system, however, with high levels of gas generation that let Xcel commit differently, with better information. SPS is a coal and gas steam-based system, so the value of better wind forecasts is often very low simply because the operator would not have done anything differently, due to the limitations of the available units.

Can Wind Energy Forecasts Be Improved?

When considering how wind energy forecasts are likely to improve and evolve, it is important to appreciate the roles of both the public and private sectors. With the possible exception of very short-term forecasts, the foundation of all modern wind energy forecasts is atmospheric prediction from global numerical weather prediction (NWP) models run by federal organizations such as NOAA and the European Centre for Medium-Range Weather Forecasts (ECMWF). These predictions are used either as a direct input to the process of making wind energy predictions or as input to additional models that run over a smaller region.

The quality of both the global and regional weather predictions is a direct function first of the quality, quantity, and timeliness of the environmental data that define the initial state of the atmosphere, ocean, and land surface and second of the accuracy of the NWP model. Limitations of the data used for model initialization and shortcomings in the skill of the model yield a fundamental constraint on forecast accuracy for all predictions (not just wind energy forecasts) in which atmospheric evolution is a driver. The same constraint exists in cases where a wind energy forecaster performs its own data collection and runs its own NWP because the core data are either provided directly by or derived from the global models.

The impact and relative contribution of these data and model limitations vary depending on factors such as forecast horizon, terrain complexity, type of weather system, and the required forecast product and fidelity. For wind energy prediction applications, day-ahead forecasts usually provide a good estimate of the total amount of wind energy expected for the next day and the approximate (albeit not perfect) timing and magnitude of when that energy will appear as "power at the meter" over the course of the day. As previously noted, studies show that this information has enormous value even if the forecasts are not perfect.

Shorter forecast horizons, such as the coming 12 hours, may hold particular value for predicting ramps (rapid changes) in wind power output, and they may yield large economic benefits for many other economic sectors as well. Forecasting improvements in this time scale will require improved skill in both the global models and the more local and higher-resolution "mesoscale" models, better estimates of global environmental initial conditions, and (most important) the use of mesoscale models in a "rapid-refresh" configuration in which new observations are frequently assimilated.

Currently, most publicly available weather measurements are made near the surface (commonly at ten meters above ground level), and vertical profiles through the atmosphere are sparse and infrequent. Improved forecasting systems will likely require frequent measurements from a denser observational network that includes instruments that probe through a larger volume of the atmosphere. A high-resolution, rapidly cycling forecasting system also requires a suitable high-performance computing infrastructure.

This necessary infrastructure is unlikely to be built by the public or private sector alone. Partnership and cooperation are needed between the public and private sectors, as well as policy support at the national and international level. Stakeholders also need to define data-sharing approaches that protect the confidentiality of source data while allowing private data to be used in forecasts that benefit all weather forecast

consumers. This approach has been used by the airline industry for years, and similar cooperation among groups like NOAA, wind plant owners, utilities, and system operators could benefit all parties.

Logical "cost-benefit" business cases are important to support actions in both the public and private sectors, and a project is currently under way to contribute to this understanding. DOE, NOAA, industry forecast vendors, system operators, and university and government research groups are all working to determine the incremental value of both a new, high-resolution rapid-refresh weather forecasting model and additional observations, as described above. In this project, the private sector will provide NOAA with proprietary data from anemometers on tall towers and wind turbines at the wind power plants. This data will be used for model initialization and data assimilation along with data from more than a dozen atmospheric profilers loaned to the project by NOAA and DOE. Results are expected to be available at the end of 2012.

In addition to such technical weather-forecasting issues, however, the critical nature of market design and operating practices must be recognized. Changes to these rules will alter the critical time horizons and forecasts needed for optimally integrating wind energy, and it is important that these parameters reflect the implicit nature of the weather in a fair and reasonable way. As practices evolve to accommodate variable resources, this optimal point should consider both the cost to operations of uncertainty at different time horizons and the ability and cost to implement the necessary forecasting capability.

Conclusions

While the implicit variability and uncertainty of the weather can create challenges, as reflected in the power output of wind power plants, these issues can be addressed with improved forecasting, appropriate operating assumptions, and thoughtful market design. System flexibility must be matched to the system-level needs that are created not just by the wind power plants but by the entire fleet of generation and load. While many concepts are still in the process of developing and converging, power system planners and operators are making significant progress in support of the large additions of wind energy expected in the coming years.

As with all of our choices, we are faced with numerous cost-benefit decisions when we address these challenges. The situation is made more difficult due to the complexity and sometimes the nonintuitive nature of how weather actually behaves. Weather is not a simple phenomenon that simply slides along the surface of our planet. Many of the events that strongly influence wind power output and wind ramp events are vertical in nature and can only be resolved with advanced weather models, so traditional ground-based measurements may not be as valuable or cost-effective as intuition would suggest.

Still, significant advances are being made, with high-quality wind power forecasts now available from a number of forecast providers and new research promising continued incremental improvements in the future. Cooperation between the public sector and private sector is critical to improve the data, models, and methods that will maximize the rate of improvement. When combined with appropriate operating practices and market rules, increasing amounts of wind energy will be economically and reliably integrated into our power systems.

For Further Reading

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