NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC IVGTF Task 2.1 Report
Variable Generation Power Forecasting for Operations

May 2010

to ensure
the reliability of the
bulk power system

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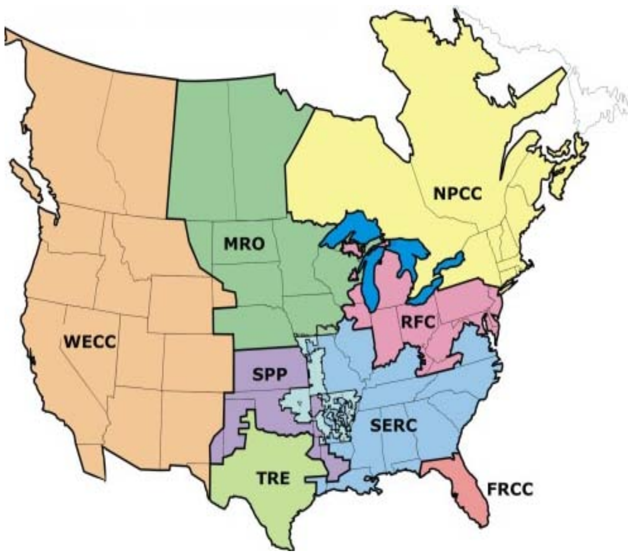
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight Regional Areas as shown on the map below (See Table A).[2] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping regional area boundaries: For example, some load serving entities participate in one region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council, Inc	**TRE** Texas Regional Entity
RFC Reliability*First* Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro, making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have a framework in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

[2] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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1. Introduction

A combination of public policy, incentives and economics is driving a rapid growth of variable generation in the electric power system. The majority of states/provinces now have renewable portfolio standards, with many requiring that over 20 percent of electricity sales be generated by renewable energy sources within the next five to fifteen years. The majority of these requirements will be addressed by adding significant amounts of wind energy and growing amounts of solar energy to the bulk power system.

Wind and solar power plants exhibit greater variability and uncertainty because of the nature of their "fuel" sources. Forecasting is one of the tools that can be used to address concerns and costs around this variability and uncertainty. This report discusses operational and market system impacts, provides background on what can be realistically expected from variable generation power-output forecasting, and proposes recommendations to deploy forecasting systems into operational use.

Variable generation also includes more than wind resources: both established types, like run-of-river hydro and emerging varieties, such as wave energy. While the majority of attention in this report is on wind and solar generation, most varieties of variable generation share similar characteristics (though to a different extent) since the variability is largely driven by weather or other non-anthropogenic phenomena. Similar forecasting and integration approaches are also likely to apply to these variable generation resources as well. In fact, because load is also influenced by the weather, demand and generation forecasting may eventually come to be viewed in a unified way.

This report focuses on the operating timeframe – from real-time to the coming 48 hours. Forecasting of variable generation resources is important in all timeframes, and there are many uses for longer-range forecasts from days and weeks (e.g., transmission outage planning and minimum generation issues) to years (e.g., integrated resource planning, where resource flexibility and ramping capabilities should be increasingly valued, and the generation mix if not appropriately planned can raise bigger challenges/issues during operating timeframe). Such longer-term schedules are adjusted as they get closer to real-time and the critical operating impacts to bulk power system reliability tend to be closer to real time. Therefore, again in the interests of focus and expediency, this report primarily discusses the forecasting requirements for the coming 48 hours and particularly considers how forecasting information can be delivered to the system operator in a useful and actionable way.

2. Background and Discussion

2.1 Benefits of size and flexibility

Even without considering forecasting, a large, flexible bulk power system provides many advantages for economically and reliably facilitating and managing variable generation. Physical size is beneficial because the correlation between the power production from multiple wind or solar plants diminishes as the distance between those plants increases. Flexibility is important; particularly the flexibility to make commitment decisions closer to real-time, since as the time frame decreases, wind and solar plants are less correlated, thus reducing aggregate variability. The reduction in correlation as a function of both timeframe and geographic spread are shown in the graphs below (Figures 1 and 2).

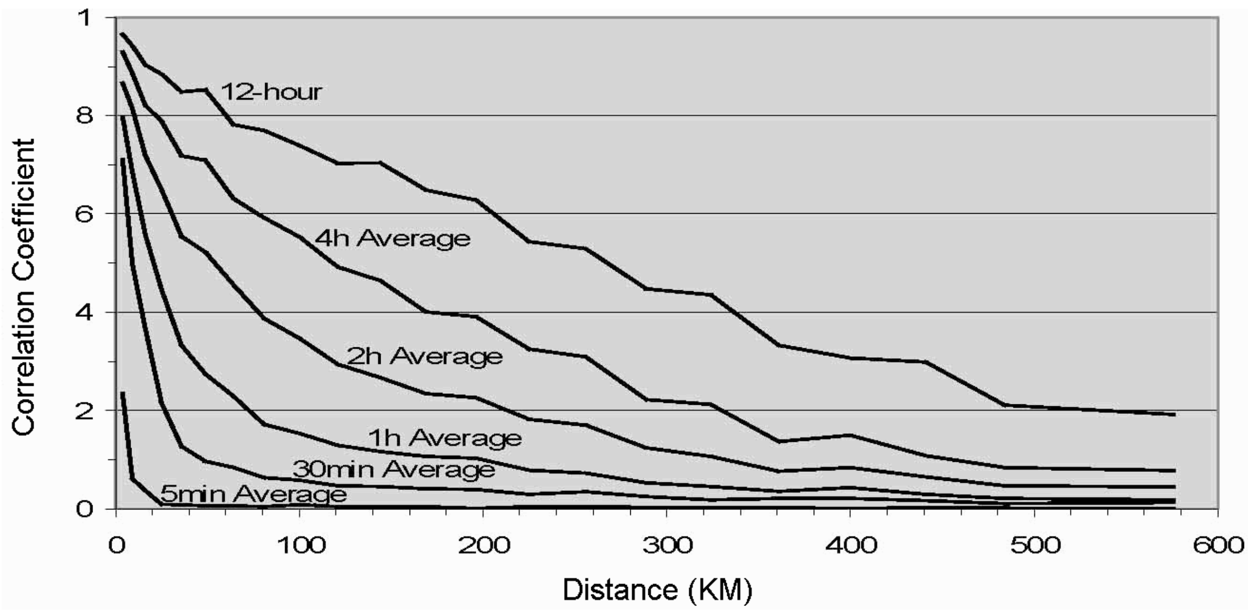

Figure 1: Wind generator variability loses correlation as the distance between machines increases and as the time frame of interest decreases [1].

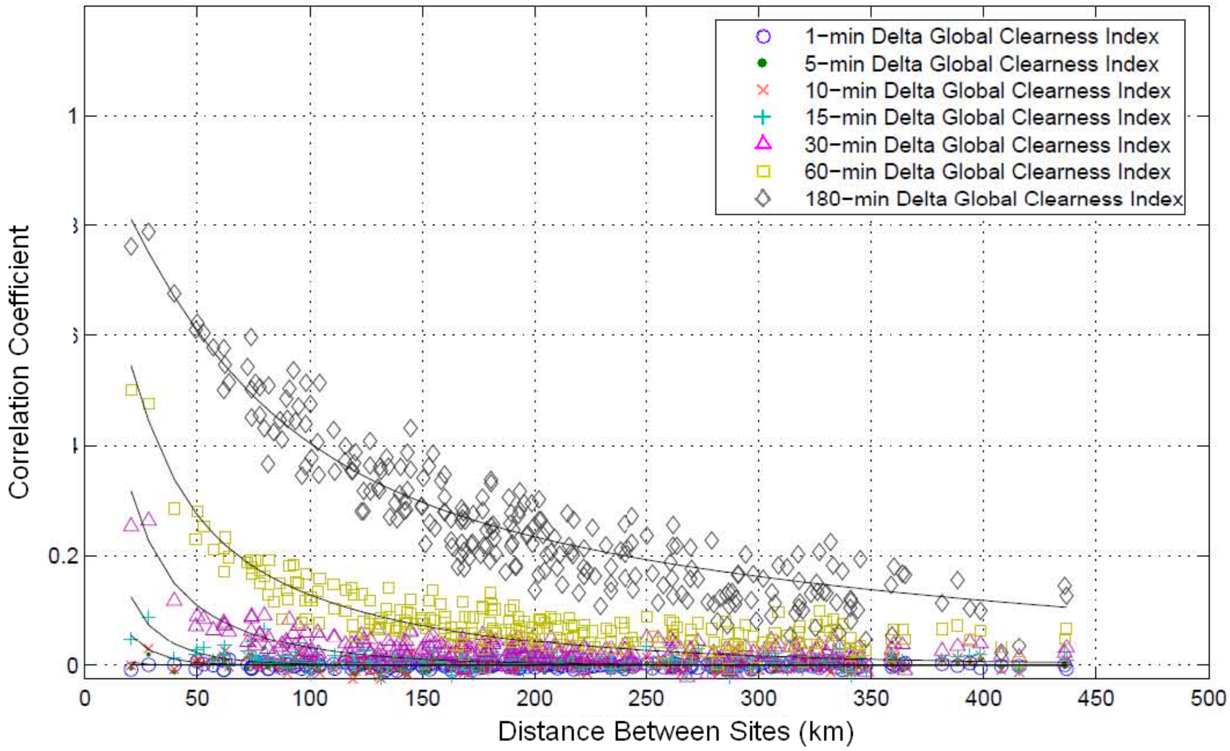

Figure 2: Like wind, solar generator variability loses correlation as the time frame of interest decreases and the geographical spread increases [16].

Larger geographic and electrical size also tends to reduce aggregate forecasting error. For example, Table 1 shows that wind power forecasting error is reduced significantly when forecasted wind output from all four regions of Germany is compared with output from a single region. In general, there can be a 30 percent-50 percent reduction in forecasting error that results from aggregation and geographic dispersion of wind power, as compared with the error of individual or geographically concentrated wind plants [3]. Therefore, in many cases power system operators can more accurately predict and plan for changes in wind generation when systems are larger and this principle may also apply to other types of variable generation.

Wind Forecasting Accuracy		
Forecasting Error (NRMSE)	**All four Germany control zones (~1000 km spread)**	**One Single Germany Control Zone (~350 km spread)**
Day ahead	5.7 percent	6.8 percent
4 hours ahead	3.6 percent	4.7 percent
2 hours ahead	2.6 percent	3.5 percent

Table 1: Wind power forecasting accuracy improves when larger geographic areas are considered [1].

In general, forecasting accuracy also improves closer to real time. With access to current information of the power plant and the weather, forecasting errors are reduced for shorter periods ahead compared to periods further into the future. Therefore, systems and markets that operate closer to real time have improved forecasting accuracy and support more frequent generator schedule changes to deal with variability. For example, hour-ahead scheduling or markets accommodate variable generation better than day-ahead schedules, and sub-hourly scheduling and dispatching are even better. A coordinated series of regularly clearing markets, or the equivalent flexibility for scheduling and dispatching in a non-market system, provides the best ability for conventional generation to adjust to changing wind and solar conditions.

For example, the New York Independent System Operator (NYISO) started operating a wind power forecasting program in June 2008 [17]. A day-ahead forecast is used for reliability and allows NYISO to consider the anticipated levels of wind power for the next operating day when making day-ahead unit commitment decisions. Forecasts are also used in NYISO's real-time security constrained dispatch. These forecasts are blended with persistence schedules[3], weighing more heavily on persistence schedules in the nearer commitment/dispatch intervals, and gradually shifting weight to the forecasts as the commitment intervals look farther out in time.

NYISO re-dispatches the entire bulk power system every five minutes, which lessens the variability of the wind resources from one dispatch interval to the next. The variability of wind output from one dispatch interval to the next would be far greater if the system was only re-dispatched once per hour. Wind forecasts for the next hours are helpful in determining if there is sufficient flexibility in the system beyond the five-minute dispatch time horizon, as persistence forecasting works very well for the five-minute time horizon.

For small or island systems where larger geographic dispersion is not a practical option, the situation is admittedly more difficult. Dispersion may also not address forecasting errors for systems where variable generation is concentrated within a geographic region to a degree that a single geographic location is critical to that bulk power system's balancing activities. For small systems with limited interchange capacity and islanded systems, imbalance in a shorter time scale than typically considered in forecasting intervals (i.e., seconds or minutes) could be desirable due to the impact of imbalance from variability on line loading and/or system frequency. In such cases, customized forecasting and possibly new forecasting techniques and/or deployment of additional field telemetry designed specifically for improved near-term forecasting for the particular geographic site(s) of interest may be necessary to provide system operators with an advance warning of potential bulk power system reliability concerns. To successfully integrate large amounts of variable generation in these small or island systems will require a combination of approaches to mitigate uncertainty, in addition to forecasting: dispatch flexibility becomes critical and special operating rules, additional weather and forecasting systems, increased use of curtailment and even additions of mitigating technical solutions such as storage may be necessary. These are specialized situations, however, and as discussed more

[3] Persistence is the assumption that the current output will be the future output, so a persistence schedule simply uses the current output value as the predicted value for the next time period.

generally in this report, larger systems will have more cost effective options for addressing the integration of variable generation.

2.2 Value of forecasts to bulk power system reliability

The value of wind plant output forecasting has been explored and quantified in a number of wind integration studies. Forecasts are valuable not only to assist the balancing area operators in performing their duties, but also to enhance the economic efficiency and manage bulk power system reliability operational affects on the remainder of the generation fleet.

Failing to consider the wind power forecast in unit commitment can lead to an over-commitment of fossil generation, inefficient use of that capacity, and potential reliability considerations. For example, in a study sponsored by the New York State Energy Research and Development Authority (NYSERDA) for the NYISO system in 2005, General Electric (GE) examined a future New York system with 10 percent wind by capacity (3,300 MW of wind on a 33,000 MW peak load system). In the base scenario, unit commitment algorithms ignored wind and dealt with the wind power as it became available in real-time. A second scenario used a simulated state-of-the-art wind plant output forecast in the unit commitment program, which led to a variable cost reduction of $95 million, ($10.70/MWh of wind energy generated) when compared to the base scenario. A third scenario used a perfect next day wind plant output forecast in the unit commitment, which provided an additional savings of $25 million ($2.80/MWh of wind energy generated) over the second scenario. As can be seen, most of the economic benefit of a wind power forecast can be realized with a currently-available forecasting system.

Similar findings were obtained in another study by GE for the California Energy Commission in 2007 [10]. For a future high penetration scenario for California (30 percent of energy from renewable generation, mostly wind), the value of a wind power forecast was found to be $4.37/MWh of wind energy, with an additional $0.95 added for a perfect forecast. When the wind plant forecast is included in the Reliability Unit Commitment, system reliability is increased through the identification of the additional reserves needed to manage the additional uncertainty due to the wind power.

Significant benefits are available with good wind power forecasts, even if the forecasts are not perfect. The magnitude of the benefit, and specific forecasting requirements, are dependent upon the degree to which the forecast can facilitate a more economic dispatch relative to the present mechanisms and ensure bulk power system reliability.

2.3 Different forecasts for different uses and time periods

There are many aspects to the forecasting of variable generation, and forecasting systems can be designed, tuned and trained to minimize error around different metrics. There are also many timeframes of interest, and different methods and models are best suited to certain timeframes. No single forecast will apply optimally to all uses. Multiple forecasting methods may be needed and the intended use of a forecast should be well defined.

There are at least four different forecasting products useful for improved power system operations and reliability:

- ***Weather situational awareness* –** A system to provide actionable severe weather alerts will improve situational awareness. These alerts can be provided in various forms, such as a web-based real-time system to enable operators to visualize and react to high wind events. An example is the high wind warning system based on a geographic information system platform that was demonstrated for Xcel Energy in 2008 [3]. Included in that system were U.S. Storm Prediction Center watches, warnings, and convective outlooks in both graphical and text format; high wind forecasts for winds exceeding 20 meters/second; and real-time color-coded high wind observations. Most importantly, operators should be able to quickly identify the amount of their variable generation that could be impacted by an extreme event.

- ***Next hours forecast* –** This is a short-term forecast, for the next six hours or so, that provides fine time resolution for the next few hours and is very important for real-time operations (perhaps augmented with an additional "ramp risk" forecast as discussed later in this report). This is used by operators for next-hour planning as well as input for operating strategies or mitigation plans and may be updated hourly (or more frequently as new data becomes available), often providing 10-minute power values for the next few hours. The value of this forecast, and the measure of its accuracy, is its ability to anticipate changes in variable generation and to allow system operators to identify and activate any additional reserves needed to maintain system reliability.

- ***Next day forecast* –** The day-ahead forecast, as described above, provides hourly power values for the next few days and is typically updated when major forecast products become available (every 6-12 hours). Often both a medium-term (e.g., the next 48 hours) and a longer-term (e.g., from 48 hours to several days) version of this forecast will be produced, based on slightly different weather models. This forecast is used in the unit commitment process and can be used for scheduling fuel purchases and deliveries for systems with significant natural gas generation. The uncertainty associated with the wind plant output forecast in this timeframe is important, and an area in which significant developments are occurring with ensemble forecasting techniques[4]. These methods can contribute toward identifying the additional reserves needed to maintain system reliability in the most economical fashion.

- ***Nodal injection forecast* –** While some would view this as a convenient aggregation of the prior forecast products, transmission operators may want to have a nodal injection forecast for their transmission congestion planning process. Aggregated forecasts are generated for each delivery node in the transmission system. By using the real-time nodal power data along with weather model forecast data, training with a computational learning system may be able to further optimize the forecasts for each node.

[4] As further discussed below, an ensemble forecast uses multiple weather forecasts, each based on somewhat different models or initial conditions, and the level of agreement between the multiple forecasts can be an indicator of the forecast confidence.

The value of forecasting is dependent on the target system state and the tools operators have at their disposal to respond to information provided by the forecast. Because of this, metrics that look only at the average forecast errors are difficult to evaluate in a meaningful way. When the system is in some states, variable generation power forecast error has very little impact on system operations. When in other states, even a small deviation may be very significant to the system. If there are limited options available to the operator, even with a forecast there may not be a means in some timeframes to adjust the dispatch in response to a change in forecast. Clearly, integrating some measure of forecasting certainty with the system state is important, as is the operator's situational awareness of both their power system and weather systems. The value of the forecast is also dependent upon the timeframe. Typical wind power forecasting, as available today, will not fully resolve operational challenges for a system for which the primary integration challenge is presented in the form of infrequent, but significant, sub-hourly changes (ramp events).

Operator experience and confidence will no doubt help this situation. Just as airline pilots came to know that weather and turbulence forecasts need not be perfect to be useful, system operators will grow with experience in their ability to use forecasts to advantage. It may be more useful to view forecasting in terms of identifying periods of operational risk or uncertainty, so operators can take mitigating action under those conditions, instead of focusing on accuracy of forecasting. In addition, more integration of forecasts and forecast certainty with bulk power system reliability analysis tools is a growing need if operators are to receive warnings of reliability concerns in a more holistic way.

2.4 Forecasting methods

Modern wind power forecasts typically use a combination of physics-based models and statistical models, with the latter often using artificial learning systems. Physics-based atmospheric models that are used for weather forecasting are referred to as Numerical Weather Prediction (NWP) models.

NWP models use equations based on the fundamental principles of physics and are core resources for most weather forecasting activities. NWP models simulate the atmospheric processes, which requires a large computational effort, but can produce useful results even for novel situations or without the use of historical data from a wind plant. However, as with even the most detailed simulations, their results are limited by the spatial resolution of the modeling grid, the fidelity of the simulation and the unavoidably incomplete knowledge of the initial state of the atmosphere, so weather forecasts are very useful, though not perfect. These models were originally developed for other general weather forecasting purposes (public safety, aviation, agriculture, etc.) rather than specifically for wind and solar power forecasting, so further incremental enhancements from both the public and private sector meteorology community will continue as renewable energy becomes a growing user of weather products.

Statistical models are based on empirical relationships between a set of predictor (input) and forecast (output) variables. Because these relationships are derived from a training sample of historical data that includes values of both the predictor and forecast variables, statistical models have the advantage of "learning from experience" without needing to explicitly know the underlying physical relationships. Some of these statistical models can get quite sophisticated, finding complex multivariable and nonlinear relationships between many predictor variables and the desired forecast variable. More advanced examples of such systems are computational learning systems such as artificial neural networks, support vector machines and related technologies.

Today, most sophisticated wind power forecasting systems use a combination of NWP and statistical models for producing the power forecasts. The basic approach is to use values from NWP models and measured data from the wind plant to predict the desired variables (e.g., hub height wind speed, wind power output, etc.) at the wind plant location. Because they can essentially learn from experience, the statistical models add value to NWP forecasts by accounting for subtle effects of the local terrain and other details that cannot realistically be represented in the NWP models themselves. But because they need to learn from historical examples, statistical models tend to predict typical events better than rare events (unless they are specifically formulated for extreme event prediction and are trained on a sample that has a good representation of rare events, as we will discuss below in the ramp forecasting section).

Many forecast systems also use an ensemble of individual forecasts rather than a single forecast. As there is uncertainty in any forecasting procedure due to imperfect input data and model configuration, forecast ensembles account for this uncertainty by generating a set of forecasts by perturbing the input data and/or the model parameters within their reasonable ranges. This requires considerable computational resources and prudent choices, but if done well, the spread of the ensemble members can be a useful representation of the uncertainty in the wind power forecast.

The relative value of different data sources and forecasting techniques also varies significantly with the forecast look-ahead period. For the very short term (next 5-10 minutes), the current production value – known as the “persistence” value – is quite accurate and difficult to improve upon very much. For forecasting the next few hours, forecasts typically rely heavily on statistical models that use the recent data from the wind plant more than NWP values, although some advanced forecasts may start blending NWP values after the first two hours or so. For longer term forecasts (from perhaps six hours to six days), NWP forecast provide most of the value to the forecasting result, since current data from the wind plant has little remaining value. After 6 to 10 days, even NWP models have little skill and climatology forecasts are used (e.g., the long term averages by season and time of day).

Wind power forecasting services are available from several professional forecasting firms. While essentially all state-of-the-art forecast systems use similar input data, the details vary substantially from one forecast provider to another in terms of the models and techniques. Recent comparisons have shown that no single approach works best for all times, conditions and locations. This suggests that there may be benefit in using multiple forecast providers, essentially getting an ensemble of forecast providers, especially if the forecast user is able to develop some skill in identifying which forecast algorithm is likely to perform better under various conditions or for different types of decisions. While ramp forecasting research is still in progress, the use of multiple providers or methods for ramp detection and other near-term, sub-hourly forecasts may also prove to be valuable.

Solar power forecasting is rather analogous to wind power forecasting, but once the sun is up during the day, clouds are the primary influence on the variability of power delivery and the uncertainty of the solar power forecast. In the short term, some clouds are relatively stable and move with the winds at the level of the cloud. Over longer time scales, clouds can change shape and grow or dissipate, so NWP methods are necessary to model cloud changes. The type of solar technology also influences the nature and timescale of solar power variability for a given weather situation.

Multiple methods will be used for forecasting solar resources at differing time scales. Short-term solar power forecasts are aided by the fact that clouds can be observed. Sky imagers near solar plants can be used to indicate approaching clouds and predict the impact the clouds will have on output. For the next few hours, successive recent satellite images have been shown to yield useful information about the direction and speed of approaching clouds and allow the position of stable clouds to be extrapolated forward into the next few hours. For longer time scales, NWP models can be used to predict clouds and solar insulation for multiple days. As with wind power forecasting, solar power forecasting will benefit from further development of weather models and datasets.

2.5 Forecast error and uncertainty

Measures of forecast uncertainty are becoming increasingly important, particularly in terms of how the forecast uncertainty integrates with conventional generation and load forecasting issues. Probabilistic tools that evaluate the impact on balancing resources of load variability and wind generation uncertainty, as well as unexpected generation outages, are needed and should eventually be integrated into Energy Management System (EMS) environments in the control room [15].

Forecast error for wind plant output predictions can be measured in many different ways. One common measurement is the Mean Absolute Error (MAE), which is simply the absolute value of the error, divided by the predicted or reference value. Another is Root Mean Squared Error (RMSE), which is similar but penalizes larger errors more than smaller errors. It is common practice to measure the error of the power with reference to the rated (nameplate) value rather than the predicted or actual value. There is logic to this, as an error of just a few megawatts during a period of low output would otherwise be inappropriately magnified. While results are highly dependent on the site, time of year, quality of turbine availability/outage data, weather conditions and other situations, typical one-hour-ahead power MAE values for a single wind power plant are in the range of 4-12 percent of rated capacity. Typical one-day-ahead values may be in the range of 12-25 percent of rated capacity, with results dependent on geography, facility dispersion, and forecast method. For a diverse set of wind plants in a broad geographic region (spread over hundreds of miles), the aggregate error will be significantly reduced – perhaps by up to 50 percent [1][13].

Although these measures provide a useful indication of overall forecast accuracy, this measure does not necessarily capture forecasting performance during operationally important but infrequent situations, such as high wind conditions with risk of high wind-speed cutout or sudden increases or decreases in output (ramps). This is discussed in more detail in the next section.

2.6 Ramp forecasting

System operators typically have higher sensitivity to ramps – large changes over short time periods. Unexpected ramp events from variable generation, such as lower probability situations when much of the wind or solar fleet is being simultaneously affected by a large weather event, can have a large impact on their ability to keep power systems within their operating specifications and manage reserves.

While there are many periods during which ramps can occur, system impacts tend to be associated with one of two scenarios. Unexpected down ramps could cause reliability concerns if the wind energy was expected and the down ramp occurs during a period when operators have limited access to supplemental generation. But system impacts are also associated with increases in wind output during off-peak periods when few traditional resources are on line. At minimum load situations, most conventional flexible generation has already been shut down or reduced to minimum levels and little system flexibility remains to further reduce other generation. Given appropriate communications and control, curtailment of the variable generation is a possible approach to such ramps. Some systems need to change their intra-day unit commitment stack during low load periods to maintain additional downward flexibility to deal with increases in variable generation.

There is value in forecasting both up-ramps and down-ramps of variable generation, particularly for wind energy, but this is not a trivial forecasting problem. Unlike a conventional power forecasting system that is optimized to minimize bulk error metrics such as mean-absolute error or root-mean-squared error, a ramp forecasting system must be optimized for identifying rare events and there will be considerable uncertainty in the results that must be conveyed in a probabilistic way. The goal is to identify high-risk periods where allocation of additional flexibility or reserves (spinning or non-spinning) is justified or where renewable output curtailment may be required to maintain system balance, while reducing the use of expensive reserves when there is little risk of them being needed for reliability. Even for a given ramp event with a given risk, the system posture will influence the level of risk posed by the ramp to reliable system operations. Wind up-ramps during load increases are more likely to be manageable than the same ramp that occurs when load is declining. A probabilistic ramp forecast would also provide a very useful input to a stochastic scheduling or unit commitment tool for power system operations.

Wind ramps result from many different weather events. Events that seem similar to the system operator (a change in delivered power) may appear to be very different to a meteorologist, and the ability to predict ramp events greatly depends on what meteorological feature is causing the ramp. A large range of such features can affect the space of a wind plant and cause ramps in the power delivered from the plant. Generally speaking, the larger and longer-lived the feature, the better it can be predicted. Meteorological features that are highly localized can be difficult to predict with much certainty. Localized events such as thunderstorms will always be difficult to predict with accuracy, but because these events will typically affect only a small percentage of the wind fleet at a given time, such localized events will smooth with geographic dispersion on larger systems.

The general public also tends to underestimate the complexity of common atmospheric events. For example, most people visualize weather events as predominantly horizontal phenomena, with weather and winds traveling along from one location to another and causing similar effects as they go. With this view, if we just had "upstream" measurements, we should be able to "see the changes coming" and better estimate their timing. In reality, this is only true to a very limited extent.

As will be further described below, some events that cause significant ramps in wind power output are more vertical in nature and can't be detected "upstream" at all. For example, the typical diurnal pattern of wind is caused by changes in vertical turbulent mixing induced by variations in the vertical profile of temperature. Depending on how solar heating interacts with the surface and causes convective mixing of the lower atmosphere, the rate at which hub height winds slow down in the afternoon (and winds at ground level speed up due to mixing of the faster winds aloft down to the ground) can be highly variable. The timing of these wind changes during the day can be difficult to precisely predict, and upstream measurements provide little help.

The nature of up-ramp and down-ramp events may also differ. For example, situations that can cause up-ramps include the following:

- ***Cold frontal passage –*** The strongest winds tend to be behind the front and can persist for many hours following frontal passage. As a large feature, these events are usually predicted quite well in a general sense, though the exact timing of the passage may vary (weather systems speed up or slow down in complex ways) resulting in uncertainty around the timing of the ramp.

- ***Thunderstorm outflow –*** These events can be very localized, abrupt and difficult to predict. The extent to which this will create a significant system-wide ramp will depend on the size of the thunderstorm complex and the geographical dispersion of the wind plants.

- ***Rapid intensification of an area of low pressure –*** These are larger-scale features, which are usually forecast fairly accurately within 12-24 hours of occurrence. The longer the forecast lead time, the more error there is in the forecast of these events.

- ***Onset of mountain wave events (lee of mountain ranges) –*** Large amplitude mountain waves can develop when the mid-level winds are sufficiently strong and blowing nearly perpendicular to the mountain ridgeline, and a layer of very stable air exists at or just above mountain top level. The net result of these mountain waves is strong, extremely gusty down slope winds. It is difficult to forecast the onset and intensity of mountain wave events because small differences in topographic shape and orientation, and small differences in atmospheric conditions, can mean the difference between an event or a non-event. Mountain waves can also be highly localized with one area experiencing extremely strong winds, while areas just a few miles away are calm. The type of surface cover (snow versus no snow) can also affect whether or not these strong winds actually reach the surface.

- ***Flow channeling –*** Relatively subtle changes in wind direction in the area of a mountain valley or gorge, becoming parallel to the direction of the valley, can quickly create a local "wind tunnel" effect where the strongest winds can occur inside the valley.

- ***Sea breeze –*** Localized winds caused by the temperature differences between the water and land are well known near coastal areas, but it can be difficult to predict the timing, duration and particularly the distance these winds will propagate inland from the coast before dissipating.

- ***Thermal stability/vertical mixing –*** As noted in the earlier example, this is the erosion of stable near-surface boundary layer in the morning (often in the few hours after sunrise, sometimes later in the day). The extent to which this occurs depends on what type of land use or surface cover (snow, etc.) is currently on the surface, the amount of clouds, and the strength of the winds in the lowest levels of the atmosphere.

Similarly, a wide range of different events can cause wind down-ramp events. Turbines reaching their cutout speed are often cited as a major cause of down ramps (most wind turbines are designed to shut themselves down at 25 meters per second, or about 55 miles per hour, to protect the equipment), but these events are not as common as many believe. More often, the down ramp is caused by decreasing winds from meteorological causes rather than turbine cutouts from increasing winds.

Examples of meteorological events that can cause down ramps include the following:

- ***Near-surface boundary layer stabilization at sunset/nightfall –*** The complexity of this forecast problem cannot be overstated as boundary layer heating and cooling rates that impact the timing and intensity of ramp events depend on a number of variables such as what type of land use or snow is covering the surface, the amount of clouds, the strength of the winds in the lowest levels of the atmosphere, and the underlying soil moisture.

- ***Relaxation of pressure gradient as high pressure moves in following cold front passage –*** As noted above, the strongest winds tend to be behind the cold front, and the speed at which these winds fall off once the front has moved through can be challenging to predict.

- ***Pressure changes following the passage of thunderstorm complexes –*** Given the localized nature of thunderstorms and the dramatic pressure changes that can result, these events are not easily forecast with numerical weather prediction models.

- ***A decrease in wind speed as a warm front passes –*** Warm fronts tend to be very slow moving, and the winds immediately along the front tend to be weaker than the winds both north and south of the front. This can create a down-ramp/up-ramp event as the front passes. This occurs in the central plains and eastern U.S. where well-developed warms fronts are observed. The complex terrain of the West makes it difficult for consistent warm air masses to develop.

Down ramps can be more difficult to forecast because they are usually not directly associated with sharply defined meteorological features - thunderstorm complexes being the exception. Areas of complex terrain are also especially challenging, as there can be many terrain-induced local flows that are not captured by typical forecast models.

It is difficult to make sweeping statements of the "forecastability" of ramp events because they can be caused by many things – some of which can be predicted fairly well, while others are difficult (if not impossible) to predict with current forecast models. Providing useful information in forecasting ramp events requires knowledge and experience of what is causing the ramp events, and that will depend on where wind plants are located and many detailed conditions and weather events.

The data from forecast systems often contain information about the likelihood and characteristics of ramp events, but such information must be used appropriately. Small errors in forecasting the timing of a ramp produce large power errors, so approaches that focus only on minimizing power error are not appropriate for ramp forecasting. The optimization algorithm tends to "hedge" during the ramp periods by lowering the ramp amplitude and stretching out ramp duration so that the possibility of very large errors is reduced. This is the best approach if one wants to achieve the lowest Root Mean Square Error (RMSE) for all the forecast intervals, but it is not a good approach if one wants to provide the most useful information about ramp events.

The challenge, and currently an area of active research and development, is to extract this imperfect ramp event information from the forecast system and present it in a way that provides effective decision-making guidance for the system operator. There are a number of possible wind ramp attributes that may be useful to operators, such as ramp duration, start time, and magnitude (each of which may have a range). In addition to improved ramp probability forecasts themselves, interfaces are needed to provide forecasts and situational awareness information to operators and to other control room tools in an actionable way. Even if events are difficult to forecast, there is value in recognizing time periods that pose a high risk of sudden ramp events. When periods of high risk are identified, prudent measures can be taken.

As a somewhat special case, the impact of icing events should also be noted as a cause of ramps and forecast errors. Icing of wind turbines can cause relatively rapid down ramps as turbines lose aerodynamic lift or shut down due to ice on blades, as well as up ramps as the ice melts and turbines are restarted. The precise conditions for icing are difficult to predict, so situational awareness of potential icing risk and communications with wind plant operators is important.

In addition, wind turbines have low-temperature characteristics that can sometimes result in deviations from expected power production. The higher density of cold air masses can cause increased load on wind turbines, and some types of turbines (stall regulated) have been observed to produce up to 20 percent over their rated capacity due to the air density. Cases of generator overheating have been reported in Canada and Finland from such overproduction. For these and others reasons, turbines typically have cold weather operating limitations for temperatures below about - 22°C (or, if turbines are equipped with special cold weather options, a lower temperature such as -30°C). Situational awareness of cold weather limitations on wind turbines and communications with wind plant operators during frigid weather is therefore important.

2.7 Forecasting data requirements

Real-time wind turbine power output, availability, and curtailment information is critical for wind power forecast accuracy because once wind speed and direction values are obtained from the weather forecast, it is necessary to convert the weather model output values into power forecast. This is typically done with the assistance of a physical model, a statistical analysis process, an artificial intelligence-based learning system, or some combination of these techniques. All of these techniques also rely on historical wind plant output time series data from the site to perform the analysis, correlations, and training of the system to produce an accurate forecast.

To improve the accuracy of the forecast, it is important that both the historical data (for training, if available) and the real-time data (for forecasting) provide accurate information about turbine availability, future known outages and curtailment. Most forecasting system providers will also want meteorological data from the site, ideally both historical and in real time. If historical data is not available, such as for a new wind plant that is just commissioned, most forecasting systems can provide an initial (untrained) forecast and then improve the performance of the forecasting system as more historical understanding of the wind plant is obtained over time. The performance of the forecast will likely be degraded during the early months of the forecasting, but will improve over a year or so as the system is trained to better reflect the actual behavior of the plant.

Availability information from the wind resources can be as important as incorporating forecasts into operations. This information is also necessary for the balancing area operator in order to ensure sufficient and also economic integration of the resources. For example, knowing turbine-level availability at wind plants can affect the operating decisions leading to sufficient contingency reserve and ramp down capability to accommodate the level of penetration in actual operations.

To summarize, the data that should generally be considered a standard requirement for wind power forecasting would be the following:

- meteorological information (wind speed, direction, temp, pressure, humidity),
- power output,
- wind turbine outage/availability information (including icing-related issues), and
- plant curtailment information (including deployment instructions in MW and/or estimated MW output available if a current curtailment is lifted).

2.8 Advantages and disadvantages of centralized forecasts

As previously discussed regarding forecast error and uncertainty, forecasts are more accurate when they are aggregated to include a large number of geographical areas rather than a single plant. The accuracy improvement available from a forecast over a larger geographical region compared to a single plant can be seen in Figure 3. For example, over a distance of approximately 1,000 km, typical for a German forecast, the error is reduced to 42 percent of that for a single point forecast.

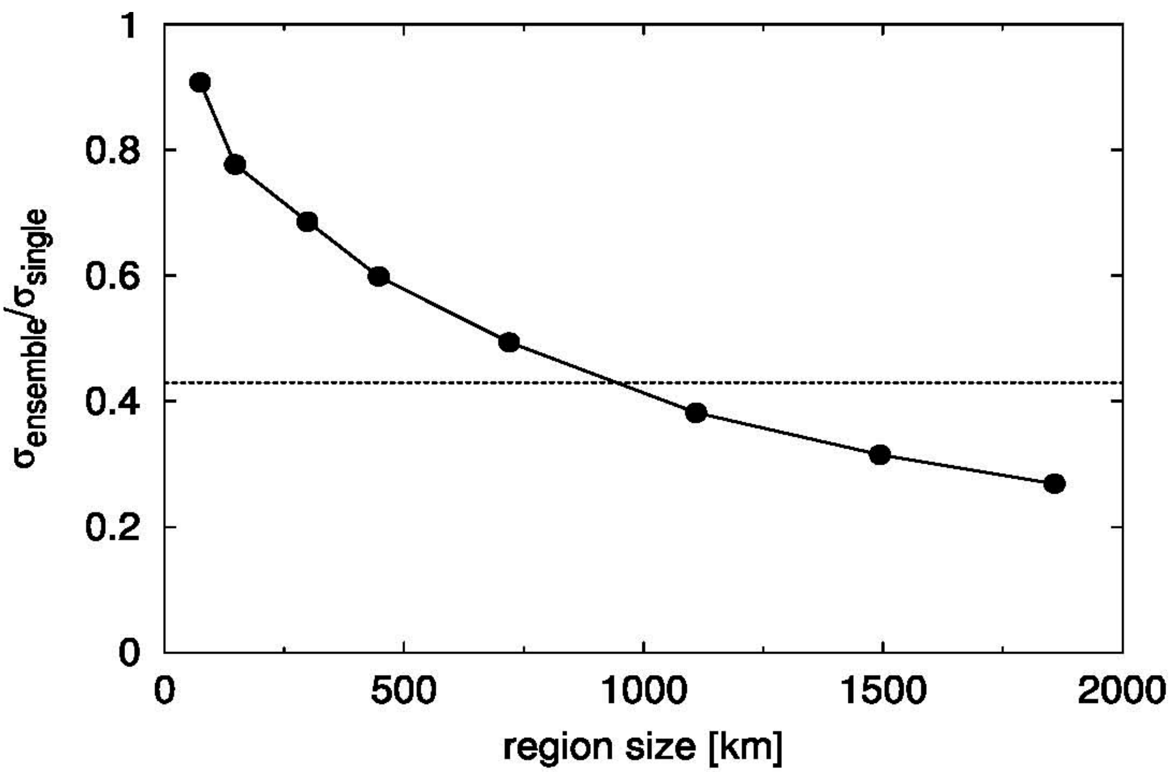

Figure 3: Reduction in forecast error with region size [13].

Such aggregation can be done either through a centralized forecasting program (the system provider managing the forecasting of all wind or solar projects) or by aggregating individual forecasts from all the wind plants (where each wind or solar project provides a forecast, perhaps from different forecasting service providers). In the interests of efficiency and convenience for the system operator, the trend today is toward central forecasts for the system or market operators. This can be seen in the high penetration wind areas in Europe (Germany, Spain, Portugal, Denmark, Ireland), as well as in the U.S. and Canada (California Independent System Operator, New York Independent System Operator, Electric Reliability Council of Texas, PJM Interconnection, Midwest Independent Transmission System Operator, Alberta Electric System Operator, Hydro Québec). The Independent Electricity System Operator (IESO) in Ontario is also in the process of implementing a centralized wind forecasting service in 2010.

Centralized wind power forecasts do offer some advantages. A centralized wind power forecast will use a consistent wind power forecasting approach and method, which will likely lead to more consistent (although not necessarily more accurate) results. The system operator may have access to wind generation data (and perhaps onsite weather data from all the wind plants) that individual wind plant forecasts cannot obtain because of proprietary or confidentiality reasons. It may be more convenient to customize or interface a centralized forecast with system control applications or dispatcher visualization systems. Also, a centralized wind power forecasting system may have a lower cost of forecasting per individual wind project compared to decentralized forecasting systems because of economies of scale and volume pricing with a single forecasting provider. In addition, the system operator may be able to specify the characteristics of the forecast to maximize its usefulness for system operation (as opposed to market signals that may involve various hedging strategies by the relevant parties).

However, centralized forecasts also have some obvious disadvantages. Since they are often based on a single forecasting method and provider, the “more consistent” result will often be “more consistently wrong” or biased for certain weather conditions or events and could lead to larger system error. When a centralized system is in place, competition and the ability to compare alternative results may be reduced, potentially slowing innovation. Additionally, the time required to fully implement a centralized forecast system can be negatively affected by challenges in obtaining all the necessary data. For example, a system operator may not have direct access to site-specific meteorological data and it may take time to gain access unless the appropriate rules are in place. Further, even though centralized forecasts may be suitable for use during the commitment stages, transmission congestion is usually driven by local area concerns and the quality of the local forecast for a smaller number of wind plants comes into play.

Therefore, while the implementation of a centralized forecasting system is a good and natural initial step for most system operators, care must be taken to ensure ongoing innovation and improvements in the generation and integration of variable generation power forecasts. There are at least two good ways to do so:

- ***Encouraging improvements and competition in wind power forecasting –*** A single forecasting approach is not ideal. Alternative forecasts can be encouraged through markets that financially motivate plant operators to do their own forecasting, operating rules that provide benefits to plant operators that provide additional forecasts to the system operator, or the use of an appropriate decentralized forecasting approach rather than a centralized single-provider forecasting system. Financial benefits are a strong motivator, so incentives are often better than mandates.

- ***Move toward ensembles of forecasts and forecasting providers –*** The benefits of a diversity of forecasts and opinions are significant, so some system operators such as those in Germany [1] have already implemented ensemble methods (i.e., systems that learn from a larger number of methods or forecast providers) that use five or more forecasting services. This is discussed in more detail later in this report.

2.9 Using forecasts in market operations

When the unit commitment process is centralized, wind integration studies have shown very significant benefits of using a wind power forecast in the day-ahead unit commitment process [7][11]. If the contributions from wind power are not taken into account when producing the optimized unit commitment schedule, then conventionally fueled generators are used inefficiently when wind energy is added to the system in real time. Indeed, the economic gains reported from use of the wind power forecast are savings to other generators and to retail electric customers (not the wind generators themselves) due to more efficient dispatch, saved fuel and reduced O&M charges. In addition, the centralized Reliability Unit Commitment identifies the additional reserves needed to maintain system reliability, as well as the congestion points that need to be relieved.

The economic and reliability gains from using wind power forecasting can only be realized if wind power forecasts are integrated with day-ahead schedules. Some may initially argue that this would represent a significant change in procedure for ISOs/RTOs, or even a preferential treatment of wind relative to other types of generation in the market system. However, much as with an ISO/RTO's creation and use of a load forecast today, the ISO/RTO's creation and use of a combined "load net wind" forecast could be used after clearing the financial day-ahead market in the reliability commitment process (usually considered the first stage of the next day's real-time market).[5] The ISO/RTO process to commit sufficient resources to supply anticipated load may have to make some provision for the increased uncertainty around the wind power forecast. The "load net wind" forecast should contribute to more efficient market operation and dispatch, improve the overall operating reliability, and should not financially benefit wind generators over what they would otherwise receive as price-takers in the real time market, so this is quite analogous to the use of an improved system load forecast that is created by the ISO/RTO.

In addition, after using the market to clear day-ahead financial markets, the system operator will likely use the forecast as part of the security-constrained unit commitment process (SCUC). This may differ somewhat from the market, in which parties may be financially hedging their positions. The objective of the SCUC process is to ensure that sufficient generation is available to provide reliable operation.

Admittedly, there may be system- or market-specific issues that require further study. For example, the available forecasts and tools must be investigated to ensure that they are sufficiently accurate for use in security constrained unit commitment. The forecast error may be also reflected in the day-ahead commitment schedule and prices, and issues around responsibility for deviations from the forecast must be considered (for example, is it appropriate to uplift this forecast error financial impact to the entire marketplace). So while more investigation on risk analysis and cost allocation may be needed, the value of incorporating the wind (and eventually,

[5] This stage, called the Reliability Assessment and Commitment process in the Midwest ISO, for example, is the first step to ensure that actual anticipated demand can be met with actual available physical resources. In most Regional Transmission Organization markets, the day-ahead market is financial only and does not serve to supply the forecasted demand for the next day.

solar) power forecast into unit commitment planning is so substantial from both an economic and reliability point of view that such investigations should be pursued with some urgency.
When the unit commitment process is decentralized or bilateral, creating transparency and continuity in dispatch is challenging. Parties marketing and scheduling generation (variable or otherwise) consider their scheduling plans market-sensitive information and therefore there is often no transparency to other market participants or even to system operators beyond very short term scheduling windows. Beyond concerns about market sensitivity, the generation schedulers often view the risk proposition differently than system operators. Schedulers often apply experience to forecast results, but those experiences and the risks that they are hedging against may not be the same that would concern a system operator. This should be expected, since an efficient economic outcome from the standpoint of a scheduler is often achieved through maintaining maximum optionality and flexibility, while system operators seek to understand and capture uncertainty in order to diagnose and then treat potential reliability risks by maintaining sufficient access to generation to respond to those risks.

2.10 Using forecasts in the operating environment

System operators continually seek to maintain sufficient operating flexibility to balance load and generation. Historically, this has involved a few key components: regulating capability to respond to second-to-second variations, load following capability that is most critical during load pickup and drop off periods, and contingency reserves to address unplanned loss of generation.

The addition of significant variable generation can alter the dynamics of this response. The periods of significant up and down ramp are not necessarily tied to the daily cycle of loads under high penetration levels, but instead are more volatile and less well understood. In addition, the system operator may not yet have information about the confidence level associated with schedules or other influences that may affect the quantities that are ultimately scheduled. Without proper forecasts and tools, these elements will tend to require the system operator to maintain additional upward and downward flexibility on an ongoing basis. With appropriate forecasts and tools, the goal is to only commit or de-commit such additional flexibility when it is justified and needed, thereby leading to more economic and efficient operation.

While a significant amount of effort has gone into developing accurate wind plant output forecasts for real-time, hour-ahead, and day-ahead planning purposes, much work remains to integrate the forecasting products into the software and systems used in the short-term planning and operation of electricity systems. The major software vendors are just beginning to pay attention to this emerging need. Based on modeling and simulation work done to date, there are reliability and operational benefits that can only be addressed by integrating the forecasts into the operational tools and procedures. The Western Wind and Solar Integration Study (WWSIS), pending at the time of this writing, are expected to advance the research regarding flexibility operating relationships between load and renewable resources [18].

There reaches a point where a fully automated forecast will see diminishing returns. A human forecaster can add considerable value in forecasting ramp events, especially in the one-hour to four-hour timeframe. There are patterns and features (such as rapidly evolving thunderstorm complexes on a radar display) that well-trained humans can still detect and interpret far better

than numerical models or computational learning systems. The challenge becomes how to use the human input to best deliver forecasts and information to the system operators.
The concept of a specialized Renewable Management System Operator is also attractive. This approach can focus on the unique aspects of variable generation, working more closely with the forecast providers and human forecasters, and then pass on to the system operator an aggregated and summarized forecast (an approach similar to this is currently used in Spain). This could relieve the system operator from many of the forecast issues and individual trends of variable generation but still give them the necessary information for their normal duties.

In addition, system flexibility will tend to be even more useful and valuable as penetration levels of variable generation increase. Operators may lack access to sufficient resource flexibility if resource planning processes do not account for flexibility requirements beyond peak load (e.g., the value of ramping and quick start), if the operator structurally lacks access to that generation (e.g., outside the balancing authority footprint, or otherwise not available for dispatch by the operator), or there is insufficient transmission. Resource planning processes should include such considerations and be conducted with the expectation of growing renewable energy penetration in mind.

A forecast can better inform operator about changes on the system, but does not change the system balance. A forecast provides value only when operators can receive the information in a manner that is useful, and have the necessary resources and mechanisms in place that enable them to take actions in response to the forecast.

2.11 Multiple forecasts

Given the value of incrementally better forecasts, the methods used in Germany deserve further consideration. System operators, such as Amprion GmbH, find value in obtaining multiple forecasts from multiple (five or more) third-party forecasting services, paying each service a market rate for their forecasts, then doing an internal ensemble of the multiple forecasts to provide a better operating forecast than would be obtained from any single forecasting provider.

While adding some cost, this approach does provide a system forecast with lower error while also supporting a more vibrant, competitive and innovative marketplace for wind power forecasting services. Since the performance of the multiple forecasting providers is directly available to the system operator for their particular system, the system operator can provide incentives and motivations for all forecasting providers to improve their methods and results. This is in sharp contrast to current wind power forecasting implementations in North America where a “single provider” approach may limit the comparison of performance, and therefore slow the rate of innovation or improvements. This ultimately has bearing on bulk power system reliability as accuracy improvements may not be realized.

2.12 Curtailment

Variable generators are usually curtailed due to constrained transmission on some systems (mostly for wind power at this time, not solar). Curtailment may also occur due to system constraints such as excess electricity supply relative to demand and must-run generation ("minimum generation" limits), limitations in ramping capability, overloads on specific transmission facilities, availability of adequate storage resources, or other reliability reasons. Some regions, such as California, anticipate that they may eventually need to curtail to support required system frequency response/reliability if they see problems at low load or high solar hours. Curtailments may also be required during system restorations.

Wind curtailment initiatives are at an early stage of discussion or implementation. A detailed description of case studies and current initiatives can be found in [19].

Most bulk power systems do not provide compensation when variable generation must be curtailed for either constrained transmission or reliability reasons, but power purchase agreements between wind energy producers and host utilities may contain such contract provisions. Ontario has provisions to provide financial incentives to encourage wind generators to reduce production if the system is approaching Surplus Baseload Generation (SBG) conditions.

At least indirectly, the implications of the Production Tax Credit (PTC), renewable energy credits and renewable portfolio standards for wind power plants in the U.S. can also impact both economic and reliability decisions. Historically, the PTC is a significant portion of wind project revenue for the first ten years of the project and resources that are no longer eligible for the production tax credit (or elected to use an investment tax credit rather than a production tax credit) may have a different price tolerance for curtailment. The sale of renewable energy credits may also be an important source of revenue for wind and solar generators, and curtailment may also affect the ability of utilities and other entities to meet energy requirements called for in renewable portfolio standards, if applicable. Because of these factors, wind projects may be motivated to generate even if electricity prices are negative. These financial arrangements are not visible to regional markets that accommodate the resource output as a "price-taker" not eligible to set the market clearing price.

The practical implications of this can create both economic and reliability concerns. For example, in market regions such situations can create concerns if the market is not able to accommodate negative price offers as a means to prioritize the value of curtailment in the process of maintaining system reliability. In any system, when the conditions for curtailment are not specific to a single entity (e.g., excess energy conditions, overload of transmission facilities, limited downward regulation capability), the guidelines and policies, under which resources are curtailed, need to be clear and reasonable to all parties as well as efficient to administer.

2.13 Distributed variable generation considerations

The impact of distributed generation should be considered as it can affect forecast needs and requirements. This is likely to be a more significant issue for solar energy in the future, as the economics and characteristics of solar energy could lead to a relatively large amount of distributed solar generation on the distribution system. While there is some growing level of distributed wind energy, most wind energy seems likely to be installed as utility-scale wind plants on the transmission system.

From a control room and forecasting point of view, the concern with variable generation on the distribution system is due to the limited amount of visibility and control of such generation. New processes such as direct telemetry, reporting procedures and trend analyses may be required to create visibility. Such information could then be used to develop accurate forecasts, output information, and when necessary, dispatches for distributed generation. For example, in Ontario, in addition to above, the IESO plans to coordinate and provide local distribution companies with centralized wind forecasting and dispatch information to facilitate reliable penetration of distributed variable generation.

Even for a system without much visibility and control, however, this does not mean that forecasting providers cannot forecast power output for such generation. This is already done on a production basis in Germany where a large proportion of the wind and solar generation is on the distribution system [13]. Development of distribution-side variable generation power forecasts (or integrated "load net variable generation" forecasts) will have growing value, particularly when solar costs come down and the level of residential and commercial solar installations grows. These "load net variable generation" forecasts will also need to take into account price sensitive demand, dynamics of the "load net variable generation" when releasing controls, impacts on bulk power system reliability and any control of variable generation to accurately depict historical quantities. As the use of distributed variable generation increases, and it is likely to do so quite dramatically on some systems, there will be increasing needs to address visibility, forecasting and potentially some level of control for such generation.

3. Comparing Variable Generation Integration Characteristics in North America

The matrix below (see Table 2) provides a summary of system characteristics relative to variable generation integration. This is abbreviated and details of each particular system are complex. Separate reports are available for each system.

Table 2: Variable Generation Integration Comparisons

System Characteristics	PJM	Midwest ISO	ERCOT	ISO-New England	IESO Ontario	Bonneville Power	Hawaii Electric
Peak Load	144 GW	116 GW	63 GW	28 GW	24 GW	10,900 MW	195 MW
Generation flexibility	Good	Good	Moderate	Moderate	Good	Good	Good
Grid & transmission flexibility	Good	Moderate	Limited	Limited	Good	Moderate	Low
Access to neighboring markets/BAs	NYISO MISO	PJM, SPP, TVA, IESO, MAPP	Limited - 1000 MW via DC ties	NYISO, MISO, HQ via DC ties	NYISO, HQ, MISO, MI, MN, Manitoba	CAISO, BC, NW BAs	None (island)
Market or dispatch fast flexibility	Some	Some	Some	Some	Good	No market, hydro AGC	AGC and fast start
Wind - 2009 level (& wind energy percent)	2500 MW	7200 MW	8900 MW	147 MW	1151 MW	2700 MW	33.5 MW (11.6 percent)
Wind - potential level	Moderate to high	Very high	Very high	Moderate	Moderate to High	High	Limited by balancing
Wind - geographic dispersion	Very diverse	Mostly in western area	Relatively concentrated	Some	Mostly in southwest	concentrated	Limited
Solar - current level	Low	Low	Low	Low	Low	None	11 MW
Solar - potential level	Low to moderate	Moderate	Moderate to high	Moderate	Moderate to high	Low	High
Solar - geographic dispersion	Very diverse	Very diverse	Quite diverse	Quite diverse	Limited so far	Unknown	Limited
Current curtailments?	Some for transmission	Frequent for transmission	Frequent for transmission	Some for transmission	Nil	Yes, moderate	Frequent
Current reliability concerns	Low	Some	Some	Low but growing	Low	Moderate, growing	Imbalance= Freq Error
Current forecasting	Wind: hours, days, ramp	Wind: hourly for 7 days	Wind: hourly for 48 hours	None, studies	Hourly from participants	None, studies	Persistence
Current integration of forecasting	Some-dispatched	Next day and Intra-Day reliability assessment	Some-schedules & capacity	Limited	Non-dispatchable	Schedules	Some-influences reserves
Planned integration of forecasting	PI & web displays	Under consideration	Ramp forecast, risk assess	Current study	Centralized forecasting in 2010	System and individual , ramping	Study on targeted forecast
Special notes/other		Discussing dispatchable intermittent resources/negative price offers	Major transmission plans	500 MW run-of-river hydro	Feed-in-Tariff (FiT) program & major transmission plans	High wind exporter	15 MW run-of-river hydro

4. Implications for NERC Standards

One of the goals of this activity is to evaluate potential changes, which may be required in NERC's Reliability Standards. Several NERC Reliability Standards may need to be updated. The Standards potentially requiring enhancements include but may not be limited to the following:

- FAC-001 (Facility Connection Requirements) - The transmission owner's connection requirements for generation facilities (Section R2) should reflect the need for appropriate data from variable generation plants including power, availability, curtailment, etc. The Standard may require a basic level of meteorological data from wind, solar and other variable generation plants whose power output is influenced by local weather events.
- TOP-002 (Normal Operations Planning) - This Standard may need to be updated to include a section about forecasting, identifying the data submitted by variable generators as the method of providing generation information to the Transmission Operators, and also recognizing forecasting as the best way to estimate generation, albeit subject to some unavoidable uncertainty due to the variability and complexity of weather conditions.
- TOP-006 (Monitoring System Conditions) - Requirement 1.1 could be interpreted to require availability information. Since availability information is useful for forecasting the output of variability generation plants (like wind plants) with multiple turbines, this requirement should be reviewed to consider if the current language is sufficient.
- BAL-002 (Disturbance Control Performance) - The standard may need to be revised to include sudden changes in wind output as "credible contingencies" under the standard. This would ensure that these events are analyzed during reserve calculations. The applicable section of the standard is Requirement 3.1.
- COM-002 (Communication and Coordination) - The Standard may need to be revised to clarify the meaning of "voice and data links" as used in the standard. To avoid problematic interpretations, the standard should specify that "voice and data links" are those identified in Interconnection Agreements or other governing agreements between the Transmission Operators and the variable generator.
- IRO-005 (Reliability Coordination - Current Day Operations) - This Standard may need to be updated to include active monitoring of forecasting conditions such as weather fronts, icing and/or high wind conditions by the Reliability Coordinator. The active monitoring would ensure that the Reliability Coordinator is aware of conditions that may arise in the immediate future. This would create consistency with the purpose of the standard which is: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."
- NERC Reliability Standards that address the reasonable and effective use of regional forecasts and local wind/solar facility forecasts should be encouraged and used to schedule variable generation.

5. Conclusions and Recommendations

The major findings of the report are abstracted and summarized in the following Conclusions and Recommendations. A final section also discusses implications on NERC standards. Adjustments to standards should be considered, taking both the recommendations of this report and those of other IVGTF Phase 2 reports into consideration.

5.1 Conclusions

1. Aggregate forecast accuracy improves with the size of the region forecast and aggregation across broad geographical regions can significantly reduce output variability and associated operating reserve requirements. In general, the aggregate uncertainty should also be mitigated by such aggregation, but the uncertainty and impacts from rare events may require more consideration.

2. Large system or market size and system flexibility improves the operator's ability to deal with variability.

3. Methods for clear and efficient prioritization of renewable resources during curtailment conditions are important for both reliability and economics. For example, regional markets should evaluate adding negative curtailment pricing to their dispatch algorithms to encourage logical and efficient responses from all resources.

4. Variable generation power forecasts in multiple time frames are critical for both maintaining system reliability and economic operation.

5. At any given point in time, the value of the forecast will depend on the operating state of the bulk power system.

6. The accurate forecasting of ramp events potentially represents a significant challenge for power system reliability with respect to the integration of variable generation, although because the variability remains even when uncertainty is reduced, work toward improved forecasting must also be balanced with improvements in system operations and flexibility.

7. The relative value of ramp forecasts will depend in part on the system posture. Uncertainty values surrounding the forecast can be adjusted to best suit the needs of the system operator.

8. Electrical (power, availability, curtailment) and meteorological data from wind and solar plants, delivered to the forecaster and system operator on a timely and reliable basis, are critical for forecast accuracy.

5.2 Recommendations

Industry

1. Wind and solar plants require real-time meteorological and electrical data through SCADA systems using standard communication protocols for use in forecasting and system operation, including power, availability, curtailment and meteorological data.

2. Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Multiple types of forecasts and forecast optimizations are practical and important.
   a. Clarity around how a particular forecast will be used must be clearly defined for both the provider and user of a forecast product.
   b. Given the value of incrementally better forecasts, system operators should consider a multiple forecasting provider model (aka, the German approach) rather than using a single external or internal forecasting service.
   c. A ramp forecast is possible and useful, but may need to be optimized for a different use than the conventional power forecast. The “chance of ramp” indication is valuable even if it is not perfect. In fact, the complexity of weather events guarantees that ramp forecasts will not be perfect.
   d. It may be beneficial to tune the wind power forecast to take into account the state of system. Morning load pickups and evening load drop-offs may require better knowledge of the likelihood of wind ramps, and should be investigated by the system operator.
3. How forecasts are used is what really matters.
   a. Initial use of aggregate, regional and individual wind plant forecasts by reliability coordinators in the control room is a logical first step.
   b. Use of the forecast in unit commitment planning is very important. Adjusting to clear the day-ahead market with a combined load and wind power forecast (rather than ignoring the wind) would improve both the economics and reliability of system operation.
   c. Probabilistic methods are increasingly important and the uncertainty distributions around all forecasts (including, but not limited to, the variable generation power forecasts) should be addressed more explicitly. As a minimum, the use of a “chance of ramp” forecast probability should be used to identify whether or not additional reserves are needed.
4. There are overwhelming benefits from adjusting operating rules and practices, and these adjustments may have more benefit to both reliability and economic operations than the forecasting alone.
   a. Sub-hourly markets with sufficient liquidity, or the ability to otherwise dispatch generation closer to real time with sufficient flexibility, can be very effective in addressing the variability and uncertainty of variable generation.

b. Incorporating the variable generation power forecast into unit commitment is important for economical and reliable operation.

c. Negative price offers for resources should be included in markets that do not yet offer this capability to help maintain reliable and economical operation.

d. The benefits of larger balancing areas with fewer transmission constraints are overwhelming. Resolving transmission constraints is critical because larger balancing areas lose much of the benefits associated with size if constraints are in play. Areas with sufficient transmission capacity are exploring how to achieve the benefits of larger areas through direct balancing area consolidation or through efforts at "virtual consolidation" where separate balancing areas work together on particular issues. Smaller areas, such as island systems, will have special challenges that require additional control. Larger operating areas, with minimal transmission constraints and diverse variable generation assets, should be capable of dealing with the expected levels of variable generation.

5. Ongoing innovation is needed, with both government and private industry involvement. Innovation is needed to continue to improve forecasting products. This requires multiple cooperating players:

   a. Government R&D and forecasting centers for improved data systems, model development and general operational weather deliverables,

   b. A vibrant, competitive forecasting service community to assist in the R&D, applications and services for business-augmented use of operating data with forecasting products,

   c. Developers of system operating tools and methods, both in private companies and in the system operator organizations, to deal with the true variability and forecast probability distributions that are implicit to our real-world systems, and

   d. System operators and stakeholders.

NERC

1. NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing Standard development processes including but not limited to the following Standards requiring potential changes:

   a. FAC-001 (Facility Connection Requirements) - (Section R2)

   b. TOP-002 (Normal Operations Planning)

   c. TOP-006 (Monitoring System Conditions) - Requirement 1.1

   d. BAL-002 (Disturbance Control Performance) - Requirement 3.1.

   e. COM-002 (Communication and Coordination)

   f. IRO-005 (Reliability Coordination - Current Day Operations)

   g. Investigated developing a new NERC Reliability Standards that provides for regional forecasts and local wind/solar facility wind forecasts to schedule variable generation.

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Abbreviations Used in this Report

Abbreviations	
AESO	Alberta Electric System Operator
AGC	Automatic Generation Control
BC	British Columbia
CAISO	California Independent System Operator
DC	District of Columbia
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
FiT	Feed in Tariff
FRCC	Florida Reliability Coordinating Council
HQ	Hydro Québec
IESO	Independent Electricity System Operator
IRP	Integrated Resource Planning
ISO	Independent System Operator
IVGTF	Integration of Variable Generation Task Force
MAE	Mean Absolute Error
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent Transmission System Operator
MRO	Midwest Reliability Organization
NPCC	Northwest Power Pool Coordinating Council
NRMSE	Net Root Mean Squared Error
NWP	Numerical Weather Prediction
NYISO	New York Independent System Operator
NYSERDA	New York State Energy and Research Development Agency
PJM	PJM Interconnection
PTC	Production Tax Credit
RFC	Reliability*First* Corporation
RTO	Regional Transmission Organization
SBG	Surplus Baseload Generation
SCADA	Supervisory Control and Data Acquisition
SERC	Southern Electric Reliability Corporation
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
WECC	Western Electricity Coordinating Council

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