UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

INTEGRATION OF VARIABLE ENERGY RESOURCES	**))**	**Docket No. RM10-11-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO THE FEDERAL ENERGY REGULATORY COMMISSION'S JANUARY 21, 2010 NOTICE OF INQUIRY ON THE INTEGRATION OF VARIABLE ENERGY RESOURCES

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") is pleased to provide these comments in response to the Federal Energy Regulatory Commission's ("FERC" or the "Commission") January 21, 2010 Notice of Inquiry on the Integration of Variable Energy Resources ("VER NOI").[1] NERC appreciates FERC's leadership in preparing the VER NOI to solicit comments on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources into the electric grid in order to determine the extent wholesale electricity tariff reforms are necessary. Additionally, FERC stated that it must ensure that "any reforms are consistent with the need to maintain system reliability in accordance with Reliability Standards proposed by the North American Electric Reliability Corp."[2]

NERC's mission, as the FERC-designated Electric Reliability Organization ("ERO"),[3] is to ensure the reliability of the bulk power system in North America by, in part, developing and enforcing mandatory Reliability Standards. NERC's reliability mandate under section 215 of the Federal Power Act does not include authority to monitor and enforce market-based issues.[4] Accordingly, NERC's comments herein focus on the reliability impacts of integrating variable energy resources into the grid, and NERC's ongoing efforts to address reliability considerations.[5] NERC has not conducted a detailed review of each Reliability Standard to determine whether

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[1] *Integration of Variable Energy Resources*, 130 FERC ¶61,053 (January 21, 2010)("VER NOI").
[2] VER NOI at P 11.
[3] *See North American Electric Reliability Corporation*, "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing," 116 FERC ¶ 61,062 (July 20, 2006)**.**
[4] *See Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*, Order No. 729, 129 FERC ¶ 61,155 at P 109 (2009).
[5] *Accommodating High Levels of Variable Generation*, NERC Special Reliability Assessment, April 2009, http://www.nerc.com/files/IVGTF_Report_041609.pdf

modifications are necessary or new standards should be developed in light of the possible market reforms FERC is considering in the VER NOI.

NERC will, however, stay engaged in this process should modifications to the Reliability Standards be necessary as a result of the Commission's actions in this proceeding. Additionally, NERC is not providing a response to every question presented in the VER NOI but is providing for the Commission's consideration a discussion of how the proposals in the VER NOI may impact bulk power system reliability.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. DISCUSSION

In response to FERC's specific questions for Response, NERC submits the following:

Data and Forecasting

> *Question No. 1: What are the current practices used to forecast generation from VERs? Will current practices in forecasting VERs' electricity production be*

adequate as the number of VERs increases? If so, why?

NERC Response:

Current practices will not be adequate as higher levels of VERs are reached because the variability and ramping effects of VERs may have a significant impact on system reliability and market operations. Forecasts and information regarding these forecasts must be integrated into day-to-day reliability processes and operations to ensure that system operators and market participants (where applicable) can create operating plans, secure necessary resources and/or respond (*i.e.*, demand side) to keep supply and demand in balance on a real-time basis and prepare for future operating conditions.

Additionally, forecasting systems can be designed, tuned and trained to minimize error around different metrics. Different methods and models are best suited to certain timeframes and no single forecast will apply optimally to all uses. The intended use of a forecast should be well defined, and multiple forecasts may be needed for optimal results.

There are at least four different forecasting products, which can be useful for improved power system operations and reliability. These are:

- **Weather situational awarenes**s **–** A system to provide actionable severe weather alerts will improve situational awareness in the control room. This can be 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 (Finley 2008). 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.

- **Real-time to the 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 (perhaps augmented with an additional "ramp risk" forecast as discussed later in this report) is very important for real-time operations. This is used by operators for next-hour planning and as input for operating strategies or Mitigation Plans. This forecast may be updated hourly (or more frequently as new data becomes available) and often provides 10-minute power values for the next few hours. The value of this forecast, and the measure of its accuracy, is in its ability to anticipate changes in variable generation and to allow system operators to perform necessary actions.

- **Next day forecast –** The day-ahead forecast, as described above in the discussion of the value of forecasts, 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 time frame is important to know, and is an area in which significant developments are occurring with ensemble forecasting techniques.

- **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 the transmission congestion planning process. Separately 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.

While a significant amount of effort has gone into developing good 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, is expected to advance the research regarding flexible operating relationships between load and renewable resources. New tools are needed to provide better forecasts. The above tools may form part of the answer, but more experience is required.

Question No. 2: What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (e.g., meteorological, outage, etc.), sampling frequency, and sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?

NERC Response:

Wind plants could provide data needed to support output forecast that could be incorporated into interconnection codes, operating procedures, and standards. Additionally, existing older plants already connected to the system should be required to comply with new requirements and standards when upgrades occur or as needed to support bulk power system reliability.

Some of the key data requirements that are necessary to develop and integrate state-of-the-art forecasts include:

- Wind speed and direction at turbine hub height;
- Breaker status;
- The number of turbines that are available and online (helps with tuning of models);
- Temperature, dew point, barometric pressure;
- Plant maintenance schedules; and
- Other observational methods to provide advanced indication of near-term wind plant changes to ensure that the operator has sufficient resources available.

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 for some operators. The periods of significant up and down ramps 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 resources to provide needed 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.

As mentioned before, 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. 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.

However, 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. Additionally, there are patterns and features (such as rapidly evolving thunderstorm complexes on a radar display) that humans can still detect and interpret far better than numerical models or computational learning systems. The challenge is in determining how best to use this input to deliver forecasts and information to system operators. For example, a specialized Renewable Management System Operator could 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 to perform their normal duties.

Some of the technical and operating challenges to plant output forecasting include interconnection codes, operating rules/procedures and standards that must be revised to ensure that necessary data is provided to prepare a useful variable plant output forecast for the System Operator.

> *Question No. 3: What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?*

NERC Response:

There is value in forecasting both up-ramps and down-ramps of variable generation, particularly for wind energy. However, 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 that will produce 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 dispatch or 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.

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 an operator's ability to keep power systems within its operating specifications and managing reserves. 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 very useful input to a stochastic scheduling or unit commitment tool for power system operations. While there are many periods during which ramps can occur, system impacts tend to be associated with one of two scenarios. First, 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. Second, system impacts can also occur when there are increases in wind output during off-peak periods when few traditional resources are on line. At minimum load situations, most conventional flexible generation may have been shut down or reduced to minimum levels and little flexibility may remain to further reduce other generation. Given appropriate communications and control, downward dispatch or curtailment of the variable generation is a possible approach to such ramps.

Wind ramps also result from many different weather events. Events that seem similar to the system operator (*i.e.*, 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 power delivered from the plant. Generally speaking, the larger and longer-lived the feature, the better it can be predicted. For example, meteorological features that are highly localized, such as thunderstorms, can be difficult to predict with much certainty, 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 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. Some events that cause significant ramps in wind power output are vertical in nature and cannot be detected "upstream." 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 ridge line, 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 forecasted 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 warm 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 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 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, which 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.

To summarize, the data, forecasting tools, and processes of System Operator's needs that should be considered a standard requirement for wind power forecasting are the following:

- Data:
  - Meteorological information (wind speed, direction, temperature, pressure, humidity)
  - Power output
  - Wind turbine outage/availability information (including icing-related issues)
  - Plant curtailment information (including deployment instructions in MW and/or estimated MW output available if a current curtailment is lifted)
- Forecasting Tools
  - Ensembles of forecasts focused on different timeframes and system conditions
- Operating Processes
  - Sub-hourly dispatching
  - Incorporation of forecasting into operational dispatch tools

> *Question No. 4: What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the* *pro forma* *OATT would be necessary to accommodate these requirements?*

NERC Response:

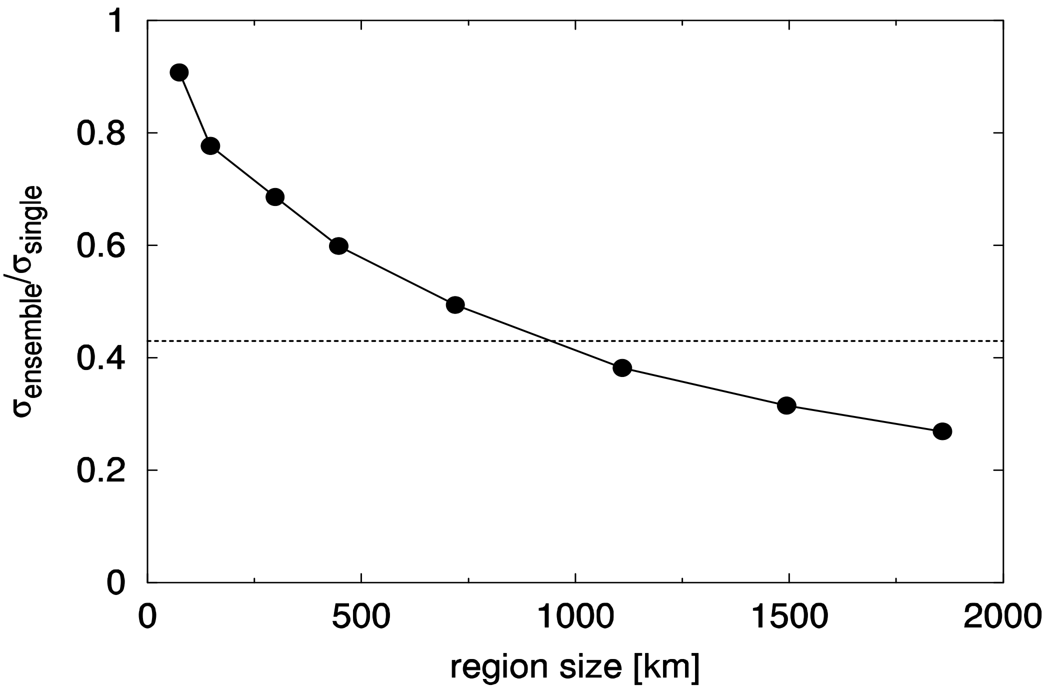
To support reliable operation of the grid, non-VER System Operators need access to forecasts, output, and outage information and need to be aware of the requirements (real-time and on a next-day basis), supporting the availability of ramping/balancing resources (including demand side options). This will provide non-VER system operators with the ability to accurately forecast generation for planning purposes.

Regarding the question on the MW size to which the data requirements should apply, model and meteorological data collection should include all VERs because they are included in the generation -load balance.

> *Question No. 6: Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting? For example, should transmission providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?*

NERC Response:

NERC believes there could be value in developing a centralized meteorological and energy producing forecast methodology. 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 the figure below. For example, over a distance of approximately 1,000 km, the error is reduced to 42% of that for a single point forecast.



Reduction in forecast error with region size (Focken, 2008).[6]

Such aggregation can be obtained 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 interest of efficiency and convenience for the system operator, the trend is toward central forecasts for the system or market operators. This can be seen in high wind plant penetration wind areas in Europe (Germany, Spain, Portugal, Denmark and Ireland), as well as in the US and Canada (California Independent System Operator, New York Independent System Operator, Electric Reliability Council of Texas, Inc., PJM Interconnection, Midwest Independent System Operator, Inc., Alberta Electric System Operator, Hydro Québec). The Independent Electricity System Operator of Ontario is in the process of implementing a centralized wind forecasting service in 2010 which is expected to support the growing penetration of wind energy in the province.

[6] *See* the presentation entitled *Facilitating Wind Development: The Importance of Electric Industry Structure*, B. Kirby and M. Milligan, (May 2008), available at: http://www.nrel.gov/docs/fy08osti/43251.pdf.

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 VER data (and perhaps onsite weather data from all VER plants) that individual VER 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.

However, centralized forecasts also have some obvious disadvantages. Because they are often based on a single forecasting method and provider, the "more consistent" result can be "more consistently wrong." Forecasting ability is stronger for certain weather conditions or events than others, which could lead to larger system error. 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.

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. Two suggested approaches to do so are:

- **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 a decentralized forecasting system 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 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.

Scheduling Flexibility and Scheduling Incentives

> *Question No. 1: Would shorter scheduling intervals allow System Operators to more efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?*

Taken together with rapid forecast updates for variable generation, which are more accurate closer to the scheduling period, a faster security constrained economic dispatch ("SCED") scheduling practice can take advantage of more current and accurate VER forecasts. Faster SCED scheduling practices spread the variability across more generators, whereas longer (hourly) scheduling practices do not provide access to the flexibility (*i.e.*, ramping and regulation reserve resources) that may be online, and therefore cause more reliance on regulating units. Inter-Balancing Area (BA) scheduling practices could also be executed at short intervals to increase efficiency. This could have the same impact across BAs as one would obtain within a BA with faster schedules.

One of the most important enablers for effective and reliable integration is the flexibility of the underlying power system to accommodate the variability of VERs. While additional system flexibility can come from many sources, such as the availability of flexible conventional resources and non-conventional resources such as storage and demand response programs, an additional contributor to greater system flexibility includes shorter scheduling intervals, for both within a BA and inter-BA, schedules.

Shorter interval intra-BA scheduling supports the spread of the VERs' variability across all of the BA's generators that respond to regular dispatch signals. This is in contrast to longer (hourly) scheduling practices that may not make use of the inherent flexibility of all of the online generators during the hour and could divert the entire system's intra-hour flexibility needs almost entirely onto its normally scarce and costly regulating resources. Shorter interval intra-BA scheduling practices could help spread the VERs' variability all across resources in multiple BAs that respond to dispatch signals.

Additionally, shorter scheduling intervals, intra-BA and inter-BA, allow BAs' dispatch mechanisms (real-time market or SCED) to use the most up-to-date forecast of the VERs' output. This is critical for better management of the uncertainty associated with the VERs' output because it is well understood that forecasting of VERs' output becomes more accurate as the time period to actual operation draws closer. Therefore, shorter scheduling intervals will reduce the need for the addition and/or operation of ancillary services in the grid – a benefit that will be magnified with the presence of VERs.

> *Question No. 2: What are the benefits and costs of allowing resources and transactions to schedule on an intra-hour basis, and what tariff and/or technical barriers exist to implementing intra-hour scheduling? Are there best practices that could be implemented to facilitate greater intra-hour scheduling?*

NERC Response:

As noted above, shorter scheduling intervals, intra-BA and inter-BA, may contribute to the better use of all system resources to meet power system flexibility (i.e. ramping and regulation reserve resources) needs.

> *Question No. 3: Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?*

NERC Response:

Based on experience, the ideal time increments that would be necessary and/or desirable in order to achieve optimum flexibility while still meeting relevant reliability requirements may be between five (5) to fifteen (15) minutes depending on system characteristics, along with the level and type of variable generation penetration. For example, NYISO re-dispatches the entire bulk power system every 5 minutes, which lessens the variability of the wind resources from one dispatch interval to the next.

For a multitude of reasons, including diminishing returns in the face of added complexity and technological limitations, the shortest interval used for scheduling is now five (5) minutes for intra-BA scheduling. Five to fifteen-minute scheduling intervals for energy transactions could assist in the large-scale integration of variable generation. For example, BAs that schedule energy transactions on an hourly basis may have sufficient regulation resources to maintain the schedule for the hour. However, if the schedule intervals are reduced, for example to ten minutes, economically dispatchable generators in an adjacent BA may be able to provide necessary ramping capability through an interconnection. Depending on system characteristics, these five to fifteen-minute scheduling intervals, whether intra-BA or inter-BA, may not be required in all of the NERC Regions.

> *Question No. 4: Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?*

NERC Response:

As discussed above, if scheduling intervals are reduced, for example, to 10 minutes or less, economically dispatchable generators in an adjacent BA can reduce the affect of the variability of VERs on schedules thereby improving reliability. Reduced scheduling intervals could also produce a system response more closely aligned with real-time events and provide closer to real-time market data for providers of demand response services. Existing and proposed NERC Resource and Demand Balancing (“BAL”) Standards should be reviewed, in accordance with NERC's standards development process, to determine their sufficiency to support such scheduling changes.

> *Question No. 5: How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?*

NERC Response:

Increasing the availability of ancillary services can support bulk power system reliability. For example, intra-hour scheduling will lead to more frequent ATC updates. Additionally, the availability of more granular ATC and E-tag information will improve the accuracy of the inter-BA scheduling process leading to better use of resources across multiple BAs to deal with VERs' variability introduced with the integration of VERs into the bulk power system.

Day-ahead Market Participation

> *Question No. 1: Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases? Will out-of-market commitments increase as the number of VERs increases? If so, why?*

NERC Response:

While NERC is not commenting on financial aspects of the increase of VERs on the day-ahead market, day-ahead variable generation output forecast is an important component to support operational reliability and should be included in day-ahead planning.

Reliability Commitments

> *Question No. 3: What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?*

NERC Response:

The reliability gains from using wind power forecasting can only be realized if wind power forecasts are integrated with day-ahead schedules. Much as with the creation and use of a load forecast, the creation and use of a combined “load net VER” forecast could be used in the reliability commitment process.[7] The process to commit sufficient resources to supply anticipated load may have to make some provision for the increased uncertainty around the VER power forecast. However, the “load net VER” forecast will likely contribute to overall operating reliability.

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.

However, 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 also be 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 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, 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.

[7] 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.

Balancing Authority Coordination

> *Question No. 6: Would a large area VER balancing authority be capable of capturing the reduced variability of VERs located across a broad and geographically diverse region? What tariff or technical limitations would prevent and/or inhibit the development of a large area VER balancing authority?*

NERC Response:

With sufficient bulk power transmission, larger BAs or participation in wide-area arrangements, can offer system flexibility when integrating large amounts of variable generation if sufficient transmission is available. For example, this can lead to increased diversity of variable generation resources and provide a larger pool of dispatchable resources, increasing the power system's ability to accommodate larger amounts of variable generation without the addition of new sources of system flexibility (*i.e.*, demand response, new supply). Balancing areas should evaluate the reliability issues and opportunities resulting from consolidation or participating in wider-area arrangements such as area control error ("ACE") sharing (*e.g.*, *see* information regarding the Western Electricity Coordinating Council's ("WECC") ACE Diversity Interchange[8]), or wide area energy management systems. In addition, the Northeast Power Coordinating Council, Inc.'s ("NPCC") ACE Diversity Interchange has been successful at limiting non-scheduled flows while delivering improvements in Control Performance Standards ("CPS").

> *Question No. 7: What reliability impacts may be associated with the creation of a large area VER balancing authority?*

NERC Response:

It would not be helpful to isolate VER in a VER-only BA, even a large one. VER is best managed with a diverse portfolio of resources, where there is a resource mix of

[8] http://www.wecc.biz/searchcenter/Pages/Results.aspx?k=ACE%20diversity%20challenge

generator/demand response providing capabilities and resources for operator's use to compensate for the variation and uncertainty from VERs.

Reserve Products and Ancillary Services

> *Question No. 2: How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?*

NERC Response:

The unit commitment and dispatch process ensures that, under normal conditions, the bulk power system will operate with sufficient capacity on-line and sufficient reserves to serve demand and respond to system contingencies. The expected considerable increase in variable generation on the bulk power system will increase the amount of operational uncertainty that the system operator must factor into operating decisions. The system operator must also have the ability to dispatch the available supply resources, including available variable generation, to deal with system reliability. In practical terms, the system operator may decide to dispatch additional capacity for ramping capability and ancillary services, use demand response, market price signals or use wind power management capability (*i.e.*, ramp rate or power limiting function) of the variable generation pre-positioning the bulk power system to withstand credible contingencies. The system operator must use operating criteria, practices and procedures, some yet to be developed, to make operating decisions based on the best available information in order to ensure system reliability.

Enhancements to existing operating criteria, practices and procedures to account for large penetration of variable generation should be developed under the leadership of the relevant reliability bodies, such as NERC, Regional Entities, and RTOs, and with full participation of industry stakeholders. It is critical that criteria, practices and procedures regarding VER forecasting, unit commitment and dispatch, reserve procurement, use of demand side resources, market price signals or use of variable generation power management functions, among others, are reviewed to assist the system operator in managing the increased uncertainty from variable generation. This could also include the consideration of risk-based operating criteria and operational planning criteria, methods and techniques.

A well-known operating challenge with variable generation is the possibility of over-generation during light load conditions when conventional generators that must be kept on line are dispatched to their minimum operating level. Under these circumstances, the power system operator must have the ability to limit or reduce the output of variable generation, according to the criteria, practices and procedures mentioned above in order to maintain system reliability during over-generation periods. For example, to mitigate the potential for over-generation conditions in response to this circumstance, BAs may consider trading frequency responsive reserves during light load conditions or explore the use of such things as batteries, flywheels, and loads to provide this capability. Greater visualization provided by state-of-the-art system monitoring technology may assist operators in managing these new resources.

> *Question No. 9: To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?*

NERC Response:

Reserve services, by definition, are the very reliable and controllable elements used to control bulk power system balance. Variability limits the usefulness of VERs for that purpose. However, reserve services (there are numerous types – regulating, contingency, reactive, *etc.*) must meet certain technical requirements for their ability to respond. To the extent VERs can meet these predefined requirements, VERs could be used to provide reserve services. However, the uncertain and variable nature of these resources may limit their abilities to provide these services on a consistent and dependable basis.

> *Question No. 10: To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?*

NERC Response:

Variable generation can and should provide frequency response as needed to support bulk power system reliability. The most effective approach is suitable interconnection standards identifying the response requirements for all power plants, based on the specific balancing area characteristics, and frequency response requirements.[9] Depending on the system characteristics and reliability considerations, sufficient frequency response may be most efficiently obtained from non-VERs, and these resources may be compensated to support frequency response requirements.

> *Question No. 11: Should the Commission revisit the reactive power requirements set forth in Order No. 661?[] What other requirements, if any, should apply to VERs to ensure that all resources contribute to grid reliability in a manner that is not unduly discriminatory?*

NERC Response:

Increasing levels of wind generation may result in de-commitment of thermal generation that has traditionally provided reactive power to the grid. It is therefore important for wind generation to provide sufficient reactive capability to support bulk power system reliability as does conventional generation.

Real-time Adjustments

> *Question No. 5: Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments*

[9] See http://www.nerc.com/docs/pc/ivgtf/Final_16_Nov_09_Interconnection_req_newis_report.pdf

during a minimum generation event? Should conventional base-load resources be offered incentives to lower their minimum operating levels or even shut down during minimum generation events to reflect an economically efficient dispatch of resources? If so, what would be the benefits and costs of doing so?

NERC Response:

Increasing levels of VERs are affecting operational issues during minimum generation events in some areas, which will likely increase with higher levels of VER penetration. These minimum-generation problems are a result of large amounts of VER generation and the inability of committed base-load generation to achieve lower turndown levels. This impact can be mitigated by: (a) more accurate VER forecasting so that unit commitment schedules can be changed accordingly; and (b) performing more scheduled maintenance on base-load units during seasons in which these events are more likely to occur (generally spring and fall). Transitioning to a future with more VER generation, particularly wind plant, which is more likely to have this effect, will require planning practices to assess needed characteristics, ensuring that the future generator fleet is more flexible with faster ramping, sufficient transmission, and lower turndown capabilities, compared to traditional, inflexible base-load generation. In addition, operating practices may need to be enhanced to ensure that sufficient capacity remains on-line to support bulk power system reliability requirements. This may mean that VERs would need to be curtailed to maintain reliability.

Question No. 6: To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

NERC Response:

For variable generation to provide power plant control capabilities, it must be visible to the system operator and be able to respond to dispatch instructions and price signals during normal and emergency conditions. Real-time wind turbine power output, availability, and curtailment information is critical to the accuracy of the variable generation plant output forecast, as well as to the reliable operation of the system. It is critical that the BA operator have real-time knowledge of the state of the variable generation plant and be able to communicate timely instructions to the plants who can then take action. In turn, variable generation plant operators need to respond to directives provided by the BA in a timely manner. The need for this information was clearly illustrated during the restoration of the Union for the Co-ordination of Electricity Transmission ("UCTE") system, (now called "ENTSO-E" or "European Network of Transmission System Operators for Electricity") following the disturbance of November 4, 2006. The lack of communications between distribution system operators ("DSOs") and transmission system operators ("TSOs") delayed the TSOs' ability to restore the bulk power system .[10]

Therefore, as small variable generation facilities grow into significant plants contributing significantly to capacity and energy, BAs will require sufficient communications for monitoring and sending dispatch instructions to these facilities. In fact, an international standard communications protocol has been prepared, IEC 61400-25, entitled "Wind turbines – Part 25-1: Communications for monitoring and control of wind power plants – Overall description of principles and models," published by the International Electrotechnical Commission, in December, 2006.[11] Further, BAs and Generator Owners/Generator Operators must ensure that procedures, protocols, and communication facilities are in place so dispatch and control instructions can be communicated to the variable generation plant operators in a timely manner.

Adequate communication of data from variable generation and enhanced system monitoring is not only a vital reliability requirement, but is also necessary to support the data

[10] http://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/report_2006_5.pdf

[11] http://webstore.iec.ch/preview/info_iec61400-25-1%7Bed1.0%7Den.pdf.

analysis posed by other recommended NERC and industry actions. In this respect, the deployment of Phasor Measurement Units ("PMUs") may become a vital planning and operational tool and assist in monitoring the dynamic performance of the power system, particularly during high-stress and variable operating conditions. PMU deployment can help power system planners, operators and industry better understand the impacts of integrating variable generation on the grid. If good communications are in place, VERs must be capable of responding to specific dispatch instructions within pre-specified and agreed upon timeframes.

IV. CONCLUSION

NERC is pleased to provide these comments in response to the Commission's VER NOI and looks forward to working with the Commission in developing programs that will ensure the reliable and efficient integration of VERs into the bulk power system.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 12th day of April, 2010.

/s/ Holly A. Hawkins
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