

# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

Special Report:  
**Ancillary Service and  
Balancing Authority Area Solutions to  
Integrate Variable Generation**

March 2011

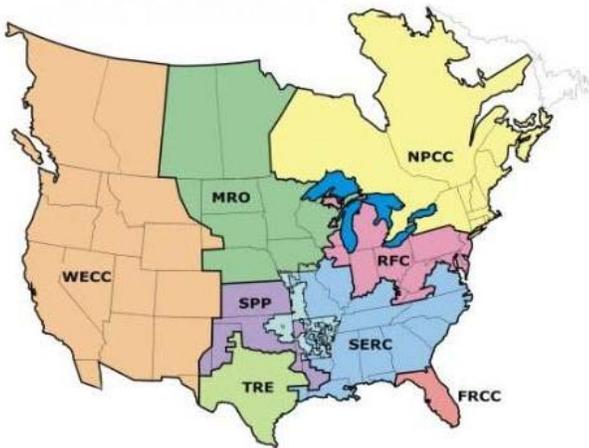
to ensure  
the reliability of the  
bulk power system

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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 (BPS) in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the BPS; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization in North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.<sup>1</sup>

NERC assesses and reports<sup>2</sup> on the reliability and adequacy of the North American BPS divided into the eight Regional Areas as shown on the map below (See Table A).<sup>3</sup> The users, owners, and operators of the BPS 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**

<b>FRCC</b> Florida Reliability Coordinating Council	<b>SERC</b> SERC Reliability Corporation
<b>MRO</b> Midwest Reliability Organization	<b>SPP</b> Southwest Power Pool, Incorporated
<b>NPCC</b> Northeast Power Coordinating Council	<b>TRE</b> Texas Reliability Entity
<b>RFC</b> ReliabilityFirst Corporation	<b>WECC</b> Western Electricity Coordinating Council

<sup>1</sup> 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.

<sup>2</sup> Readers may refer to the *Reliability Concepts Used in this Report* Section for more information on NERC’s reporting definitions and methods.

<sup>3</sup> 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

Public policy plus infusion of incentives aimed to reduce CO<sub>2</sub> footprint and, ultimately, coal consumption are driving increased variable generation use. States/provinces have mandated 20 percent or more renewable energy by 2030; and some applied stringent planning approaches to achieve their Renewable Energy Portfolio Standards (RPS).<sup>4</sup> Balancing the overall generation-demand with increasing levels of variable generation (e.g. wind, run-of-river hydro, solar) using traditional ancillary service products and operating practices can become a challenge for Balancing Authorities (BA). The BA must keep in mind the potential reliability considerations and variables involved. Enhanced tools, used daily to determine reserve operating capacities, can reduce uncertainty in maintaining generation-load balance under increased variable generation resources. Studies have shown that large-scale balancing integration of variable generation increases diversity of wind resources thereby reducing the aggregate variability over large geographic areas (Figure 1-1).

In an effort to create reliable and sound operating practices, the North American Electric Reliability Corporation (NERC) Planning and Operating Committees initiated the Integration of Variable Generation Task Force (IVGTF) to assess the need for and requisite participation in the acquisition of ancillary services from both inside and outside existing Balancing Authority Areas. The NERC Operating Committee approved the formation of this task force to study the consequences of enlarging existing Balancing Authority Areas or participation in wider and multi-Balancing Authority Area management. This multi-Balancing Authority Area management would include provisions of ancillary services from other jurisdictions, ACE sharing, or shorter scheduling intervals within and between Balancing Authority Areas to manage and spread the affects from variability of generation resources over a larger footprint. In addition, existing and proposed standards are reviewed to determine their sufficiency in response to these evolving conditions. This report developed a survey of current Regional Entity's (RE) operation and methods, including application of the RE's RPS. This assessment evaluates NERC'S Reliability Standards and includes recommendations were deemed appropriate by the Task Team.

This report includes a survey which reviews the ways that each RE copes with their daily operation on frequency response, regulation, spinning and non-spinning reserves. The regulation footprint for maintaining balance between generation and load is defined by metered boundaries within a BA Area. Within the aggregate of all BA areas, all generation and load within the interconnection is monitored and regulated for generation-load balance. As defined in BAL-005,<sup>5</sup> each Balancing Authority Area is required to have Automatic Generation Control (AGC) and to calculate Area Control Error (ACE) and deploy regulating reserve to balance resources and demand.

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<sup>4</sup> FERC Renewable Energy Portfolio Standards (RPS) updates at: <http://www.ferc.gov/market-oversight/other-mkts/renew.asp>

<sup>5</sup> North American Reliability Corporation, NERC BAL-005 AGC requirements, <http://www.nerc.com/docs/standards/rs/retired/BAL-005-0a.pdf>

The largest wind integration studies to-date in the U.S. have been coordinated by U.S. National Renewable Energy Lab (NREL) and supported by DOE. Both the Eastern Wind Integration Transmission Study (EWITS) and the Western Wind and Solar Integration Study (WWSIS) made use of mesoscale weather models to study impacts of wind and solar based generation on geographical diversity.<sup>6</sup> In conjunction, the Weather Research Forecasting (WRF) model achieved support from distinguished research community that provides operational, computational, and flexible forecasting model contributed by the research community.<sup>7</sup>

In the East, a larger scale study of the impacts of geographical diversity and weather forecasting were conducted by AWS Truewind and carried out by MISO and PJM.<sup>8</sup>

The objective of this report is to explore different practices and instill awareness of how Balancing Authority Areas depend on short/long-term planning and forecasting, complemented by sound reliability standards and efficient operating practices. Coping with high variability may occur in many ways. Balancing Authority Areas with low penetration of variable resources may rely predominantly upon ancillary services packaged in a variety of specific products. In contrast, many Balancing Authority Areas or regions with high penetration of variable resources have already developed broader regional solutions to maintaining energy balance. The general observation, however, is that increased variability requires for increased demand for flexibility of dispatch operations. Therefore, the task force embarked on answering the question; *what are the BA rules each entity most follow? Further, how will the existing 100 plus BAs operate in a homogenous way to address ancillary service requirements from variable generation?*

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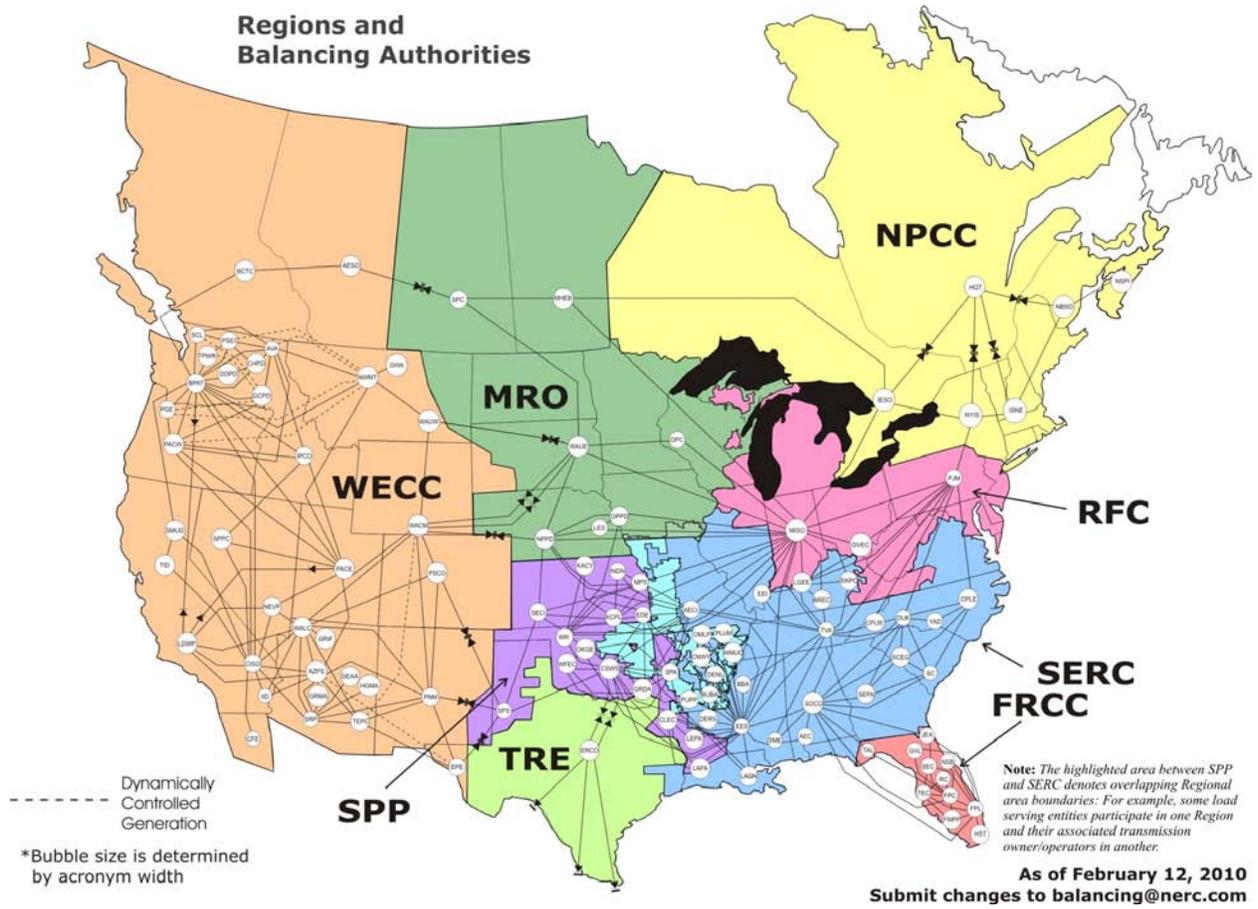
<sup>6</sup> Mesoscale Study for NREL

[http://www.nrel.gov/wind/systemsintegration/pdfs/2008/lew\\_creating\\_dataset\\_wwsis.pdf](http://www.nrel.gov/wind/systemsintegration/pdfs/2008/lew_creating_dataset_wwsis.pdf)

<sup>7</sup> Weather Research and Forecasting (WRF) model <http://wrf-model.org/index.php>

<sup>8</sup> [http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits\\_final\\_report.pdf](http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf)

**Figure 1-1: Current NERC Map of Balancing Authority**



## 2. Impacts on Planning/Operating Reserves

### 2.1 Regulation and Load Following

Wind plant variability and uncertainty increases power system reserve requirements with the impact differing over various time frames based on the inherent characteristics of aggregated wind generation. Large amounts of wind generation (thousands of MW) composed of hundreds of individual wind turbines typically cover a large geographic area. Net variability decreases with increased distance between wind turbines, as shown in Figure 2-1.

Wind plants that are only 10-20 km apart are uncorrelated in the minute-to-minute regulation time frame. This means that the regulation variability adds statistically rather than linearly. The standard deviation of a 100 MW wind plant is typically about 1MW in the regulation time frame.<sup>9</sup> A 10-GW wind fleet composed of 100 wind plants of 100 MW each would have a regulation standard deviation of 10 MW. This 10-MW standard deviation might be equal to a 50-MW regulation requirement.<sup>10</sup> Balancing Authority Areas do not provide regulation for individual loads or generators; rather they balance the regulation requirements of the *net load*. The wind fleet regulation variability will be uncorrelated with the Balancing Authority Area load's regulation variability, so those regulation

#### **Load Following or Ramping**

*Slower response (several minutes to few hours) whereby available resources are dispatched to follow system ramping requirements. Load following is not a defined FERC service, but is obtained from intra-hour and hourly energy markets.*

#### **Net Load**

The concept of net load (demand minus variable generation) or more specifically the change in net load or the net-load delta is used in this document as a metric for evaluating the need for additional flexibility that results from higher levels of installed variable generation. The demand component of the net load calculation should be consistent with the NERC definitions of demand as follows:

*Total Internal Demand: Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).*

*Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.*

#### **Tail Events**

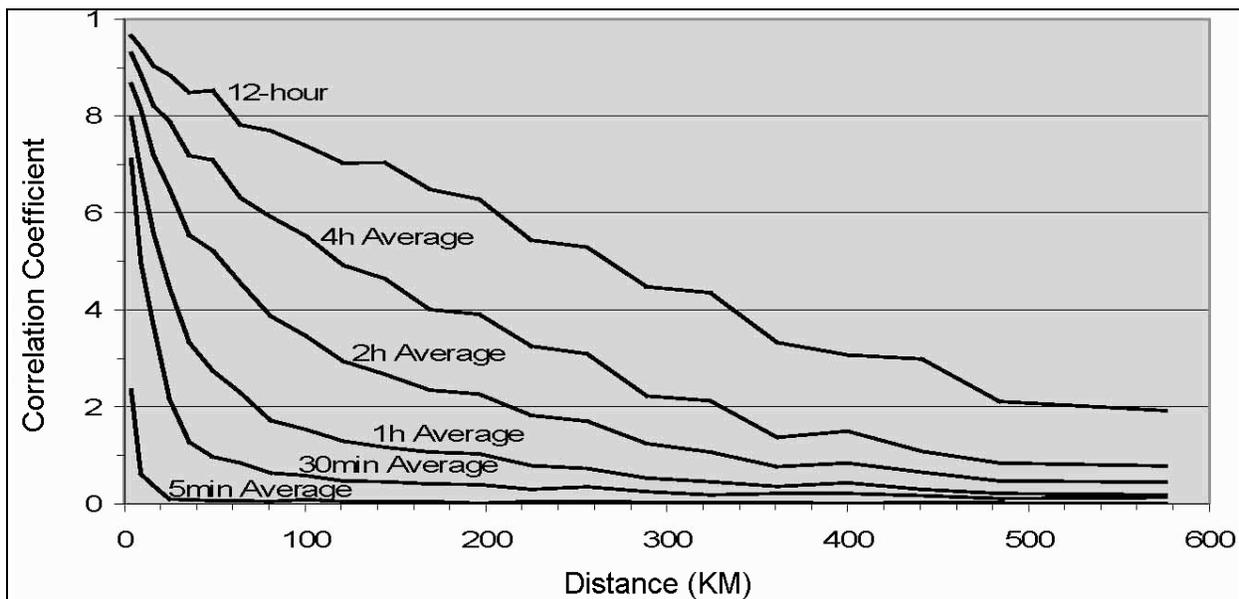
*Similar to contingency reserves, but maintained to cover large, infrequent ramps of variable generation that are typically slower.*

<sup>9</sup> One-minute variability separated from overall plant variability with a 20-minute rolling average.

<sup>10</sup> A typical Balancing Authority Area with thermal generation requires regulation capacity equal to 5 standard deviations of 1-minute variability to meet CPS requirements.

requirements will add statistically as well. If the 10-GW wind fleet represents a 30 percent energy penetration, the Balancing Authority Area has a peak load of 22 GW. A 22-GW Balancing Authority Area would typically require about 1 to 1.5 percent regulating reserve. Assuming the lower 1 percent regulating requirement, the BA would require 220 MW of regulating reserves. The 10-GW wind fleet would increase that requirement to 226 MW ( $226 = \sqrt{(220^2 + 50^2)}$ ), an increase of 6 MW of regulating reserves, to fully accommodate the minute-to-minute regulation requirements of the 10-GW wind fleet.<sup>11</sup>

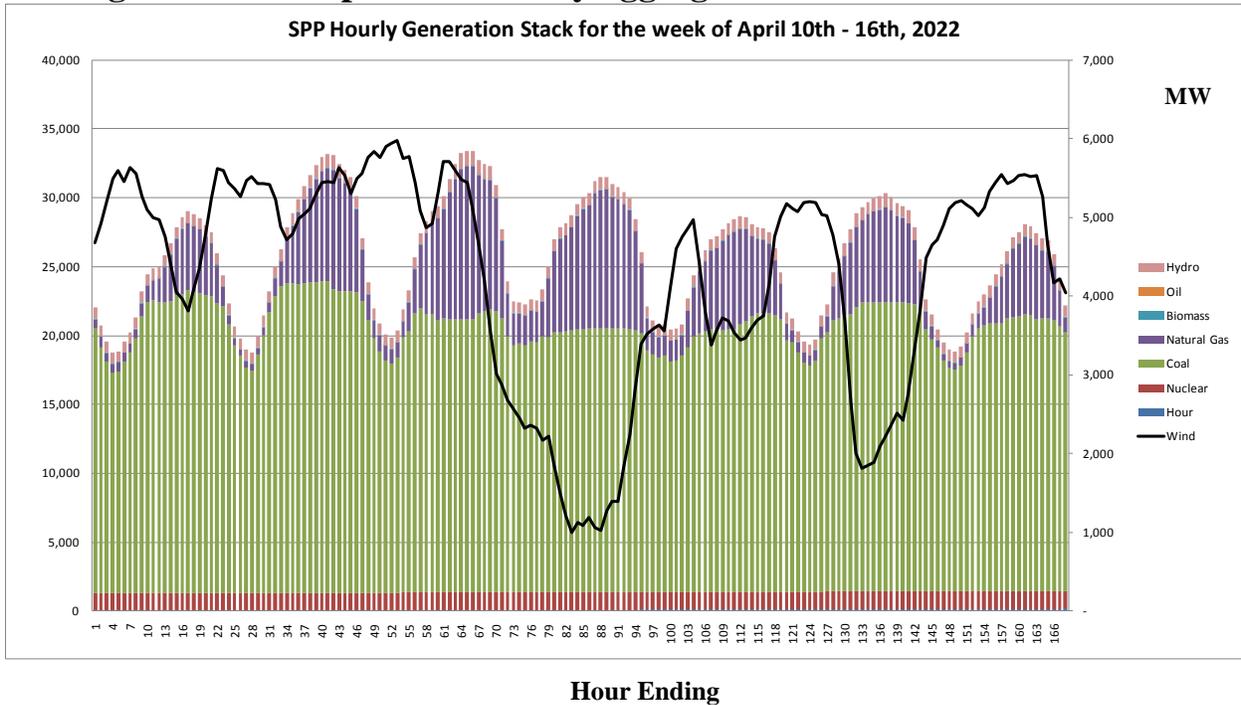
**Figure 2-1 Aggregation greatly reduces the short-term net wind variability**



This result is not surprising as loads themselves exhibit similar characteristics and results. Residential loads (water heaters, ovens, air conditioners, etc.) are each extremely volatile. They turn on and off regularly. Yet the aggregate residential load has a very low regulation requirement because the individual loads are uncorrelated on a minute-to-minute basis. Conversely, residential loads exhibit a much larger load-following requirement because individual behavior is correlated on a daily basis.

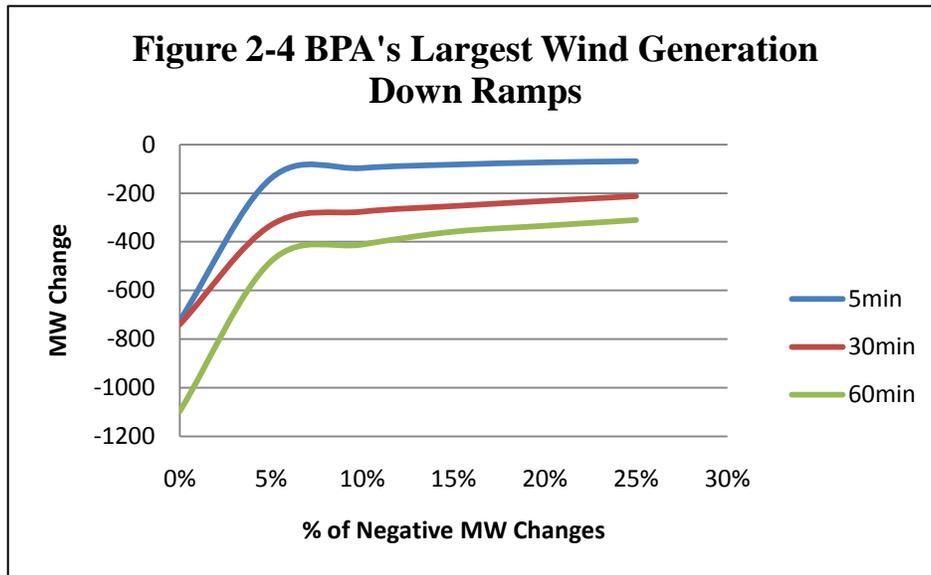
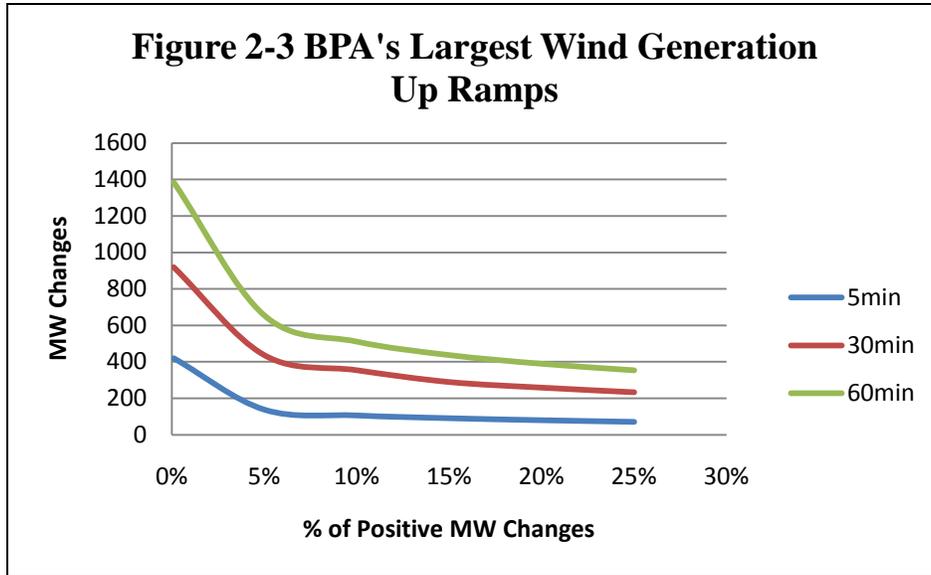
<sup>11</sup> Note that this discussion only addresses the minute-to-minute variability. Regulation is also used to compensate for short-term uncertainty and, in some regions with less access to sub-hourly response capability from energy providing generators and responsive loads, longer-term variability.

**Figure 2-2 Example of an hourly aggregation of 7GW of wind in SPP**



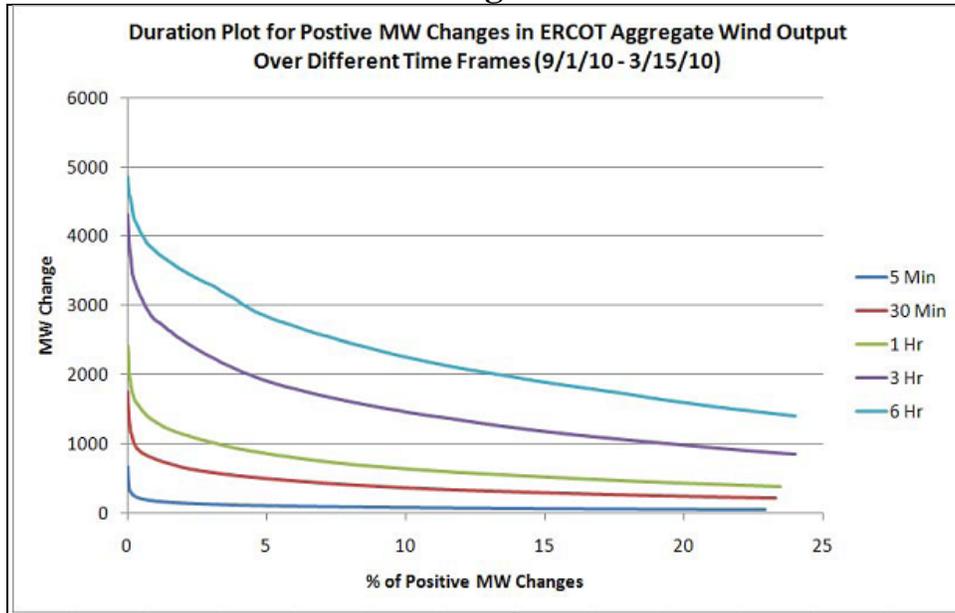
Just as residential loads exhibit larger aggregate variability in the load following time frame, so too does aggregate wind exhibit greater variability on a sub-hourly to multi-hourly basis, given an example on an hourly variability on Figure 2-2. This graphic shows the traditional generation stack within SPP for a typical week in April 2022 and the expected aggregate output of 7GW of wind plants within SPP using NREL data which correlates system loads against wind performance. Much of the time wind ramps are manageable but the tail events can be extreme and their occurrence is not predictable in the planning time-frame, which provides a challenge for planning assessments. Where load-up ramps tend to occur in the morning hours and load drops in the evening, variable generation ramps are not well correlated with time of day. For *tail events*, Figure 2-3 and 2-4 shows ramps in the Bonneville Balancing Authority. The raw data is available over a two-plus year period using distribution curves for the daily maximum 5-minute, 30-minute and 60-minute movements in variable generation.<sup>12</sup>

<sup>12</sup> BPA “Max Daily Ramps” can be found at: [http://www.transmission.bpa.gov/Business/Operations/Wind/WindRamps\\_1min\\_Summary.xls](http://www.transmission.bpa.gov/Business/Operations/Wind/WindRamps_1min_Summary.xls)

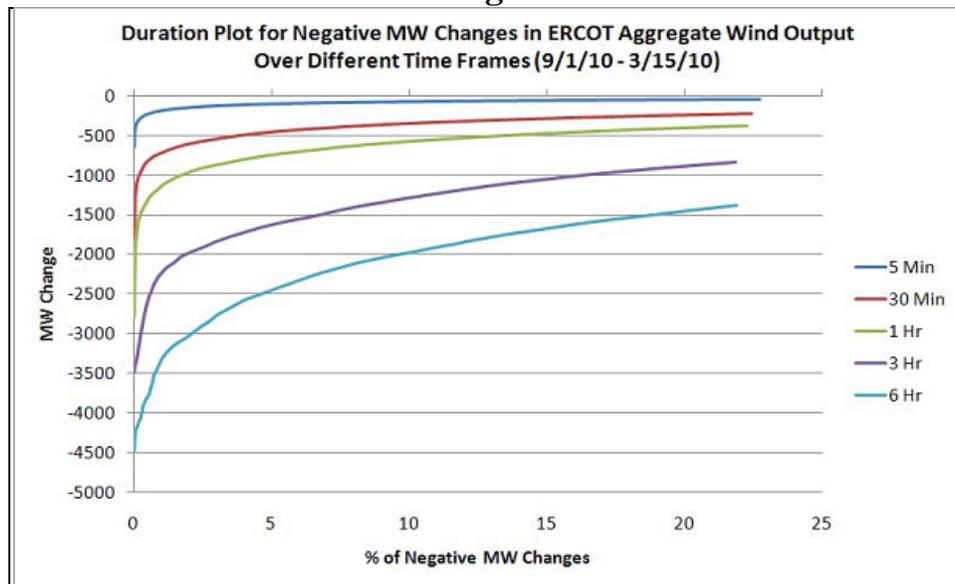


ERCOT has provided some data to illustrate actual experience as well as their ability to forecast tail events. Although largely comparable, the following ERCOT duration plots use 1-minute data to create the graphs (Figures 2-5 and 2-6). The data shown include periods in which there was curtailment. It is important to note that some amount of the observed ramps may have been wind resources responding to instructions from the ISO. Interpretation of data in duration plots needs to be clear, e.g., 5 percent of the time, during which the wind output increased over a three-hour period, the increase over that period was 2,000 MW or more. A comparison of the Figures 2-3 through 2-6 from BPA and ERCOT illustrates that wind resources in BPA are much more homogeneous in their performance compared to those in ERCOT.

**Figure 2-5**



**Figure 2-6**



Beyond the physical movement of variable generation, the uncertainty in forecasts results in scheduling errors that can lead to balancing authority intervention. While wind ramps are not as easily predicted as the daily load ramps, significant progress is being made in wind ramp forecasting.<sup>13</sup> ERCOT has developed and deployed a wind ramp forecast for its system operators. Reasonably accurate forecasts of conditions that are likely to produce wind ramps can help improve reliability by enabling the system operator to use non-spinning and supplemental reserves, rather than spinning reserves or regulation.

<sup>13</sup>Variable Generation Power Forecasting for Operations, <http://www.nerc.com/files/Variabe%20Generationn%20Power%20Forecasting%20for%20Operations.pdf>

In systems with adequate flexibility<sup>14</sup> and access to requisite generation, the primary concern is retaining sufficient flexible generation to respond to the variability associated with physical movement and scheduling error. If this generation is committed to base loads, the remaining uncommitted generation may not be sufficiently flexible to meet system requirements. In Balancing Authority Areas where sufficient flexibility is not available to support the addition of variable generation (e.g. due to balancing authority boundaries between variable generation and loads, or lack of infrastructure available to access the flexible resources), the balancing authority may need to find additional sources of flexibility to interconnect additional variable generators and to preserve reliable operations.

Balancing Authority with access to sufficient flexible generation and responsive load are keys to maintaining reliability in an environment with addition of high-levels of variable generation penetration. Because of the need to cope with these physical ramps and scheduling forecast errors, reliability is enhanced in Balancing Authority Areas that can access sufficient maneuvering capabilities of the conventional generators and responsive loads. Access to generator and responsive load flexibility can be provided through sub-hourly markets, sub-hourly scheduling, and/or sub-hourly economic dispatch, which enable operators adjust the dispatch of conventional generators and responsive loads in response to changes in projected aggregate wind output. If there are enough generators and responding loads providing sub-hourly flexibility with sufficient ramping capability to accommodate wind variability, no additional load following reserves may be required to support variable generation integration/operation. If however, time periods with insufficient generators and responding loads needed to meet NERC's Control Performance Standards CPS2 are expected,<sup>15</sup> introducing a **load-following** (or ramping) ancillary service<sup>16</sup> or capability can help augment and provide for flexibility requirements.

## 2.2 Contingency Reserves

Response speed also differentiates the contingency reserves and the operating reserve burden imposed by wind. Because individual wind turbines are small (typically <3MW for land-based turbines), they do not increase the contingency operating reserve requirements for the Balancing Authority Area or reserve sharing pool which often have a largest single contingency of 1,000 MW to 1,500 MW. Even groups of turbines or entire wind plants that use a single transformer or that are connected on a single radial transmission line are no larger than 100 MW to 200 MW. Electrical failures with individual wind turbines are not of a size that affects spinning and non-spinning reserve requirements. Wind events, which can impact an entire wind fleet can become the largest current single contingency for large wind events, though occurring more slowly in electrical terms than sudden lost of generating/transmission facilities, occurring over the course of over an hour or longer rather than in seconds. Chapter 3 discusses planning/operating reserve requirements to deal with large wind events.

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<sup>14</sup>Flexibility Requirements and Potential Metrics for Variable Generation: Implications for System Planning Studies, NERC Report, August 2010, [http://www.nerc.com/files/IVGTF\\_Task\\_1\\_4\\_Final.pdf](http://www.nerc.com/files/IVGTF_Task_1_4_Final.pdf)

<sup>15</sup> NERC's Control Performance Standards, <http://www.nerc.com/filez/standards/Version-0.html>

<sup>16</sup> Variable Generation Power Forecasting for Operations, <http://www.nerc.com/files/Variable%20Generationn%20Power%20Forecasting%20for%20Operations.pdf>

## 3. Operating Reserve Practices and Requirements

Based on the survey results, the Operating Reserve practices of the Balancing Authorities in the United States and Canada enable them to accommodate the current amounts of variable generation penetration. However, many Balancing Authorities may need to change their practices to increase amounts of Operating Reserves to match anticipated increases in variable generation integration. For example, this may include adding additional Ancillary Service products. A ‘typical’ Balancing Authority has access to a Regulation Reserve Ancillary product complementing existing amounts of Spinning Reserve and Non-Spinning Reserve. Currently, Balancing Authorities deploy a combination of Regulation Reserve and Load Following/Market dispatch to follow most of the variability attributed to variable generation changes. However, depending on the size of the Balancing Authority, there may be times when sufficient ancillary services may not be available causing de-commitment of variable generation to ensure the reliability of the bulk power system. The timing of this commitment decision will be based on the flexibility of existing and projected generation available to the operator of the Balancing Authority. A Balancing Authority with limited internal or external access to ancillary services may need to de-commit variable generation sooner than a large geographically diverse Balancing Authority, though they may also reach this point as variable generation integration increases. The need for flexible resources must be considered in evaluating the future generation portfolio requirements for any system.

### 3.1 Variable Generation Output Forecasts

Forecasts of wind generation output ramps are vital to support operators’ ability to secure sufficient Operating Reserves.<sup>17</sup> Availability is assumed when the hours of additional Operating Reserves can be increased to match the timing of the ramp (i.e. schedule additional Operating Reserves two hours each side of the projected ramp to accommodate forecasting error). Additional flexibility could be procured to augment the normal dispatch of units between each dispatch time frame. In areas with decentralized scheduling, the incorporation of ramp events into unit dispatch requires coordination between schedulers of variable generation and Balancing Authorities.

Balancing Authorities maintain Contingency Reserves to meet Reliability Standards established by Regional Entities and NERC. While each of the Regional Entities has slightly different requirements, the amount of Contingency Reserves is generally a percentage of the potential loss of the largest single resource, such as the loss of generation capacity or HVdc lines, in operation. Similar to the Regulation/Load Following/Flexible resource discussion, determining whether Contingency Reserves can be used for wind related events is a decision taken by the Balancing Authority and/or NERC/Regional Entity. Whereas Balancing Authorities with variable generation penetration approaching 20 percent may have down ramps that tend to look similar to Contingency Reserve events, increased Operating Reserves discussed above could accommodate these events without incorporating them into Contingency Reserve requirements. Likewise,

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<sup>17</sup> *Variable Generation Power Forecasting for Operations*, NERC Report, June 2010, <http://www.nerc.com/files/Variable%20Generation%20Power%20Forecasting%20for%20Operations.pdf>

including ramp events in the Contingency Reserve requirement may ensure a Balancing Authority does not need to procure additional ancillary services.

The Eastern Wind Integration Transmission Study (EWITS) and Western Wind and Solar Integration Study (WWSIS)<sup>18</sup> both evaluated the impact on Operating/Contingency Reserve requirements as variable generation penetration increased. So-called “Magic Carpet Plots” developed as part of the WWSIS show a three-dimensional relationship between the percent of Balancing Authority peak demand, the aggregate percent of Balancing Authority Area variable output resources and the associated necessary amount of flexible dispatch bandwidth. Additional work is necessary to evaluate existing regional practices and potential tools, such as Magic Carpet Plots, to recommend more efficient and reliable operating methods in the future.

As wind saturation increases, the inventory of down ramp capability from dispatchable resources can be mitigated through new requirements and capabilities at the variable generation resources. For example, Xcel Energy, a Midwestern US utility with wind resources, has recently established an automated generation control dispatch capability for its Grand Meadows wind plant, which provides the capability to decrease wind generation output if supply surplus conditions exist. In some cases, this operating practice is more economic than deep-cycling coal units, de-commitment of dispatchable resources or procurement of additional ancillary services.

Based on the survey results, most bulk power systems do not compensate variable generation which must be curtailed for constrained transmission or reliability reasons. That said, in some cases power purchase agreements between wind energy producers and host utilities may contain such contract provisions.

In ERCOT, up-ramp limitations have been imposed on new interconnecting resources. The damped pickup of these wind resources has helped minimize conditions requiring the on-line generation to reduce output to support up-ramps of variable resources.

### **3.2 Incorporating Forecasts into Operations**

As identified in the NERC report entitled *Variable Generation Power Forecasting for Operations*,<sup>19</sup> information on the current wind resource output can be as important as incorporating forecasts into operations. This information is also necessary for the Balancing Authority operator in order to ensure sufficient integration of the resources. For example, knowing turbine-level availability at wind plants can affect the operating decisions on sufficient contingency reserve and down-ramp capability to accommodate the level of variable generation output into actual operations.

The province of Ontario has provisions to provide incentives to encourage wind generators to reduce production, if the system is approaching what IESO termed Surplus Baseload Generation (SBG) conditions, which occurs when electricity production from baseload facilities is greater than demand. There are limited options available to lower output from baseload generators in

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<sup>18</sup> [http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits\\_final\\_report.pdf](http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf) and [http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis\\_final\\_report.pdf](http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf)

<sup>19</sup> <http://www.nerc.com/files/Variable%20Generation%20Power%20Forecasting%20for%20Operations.pdf>

order to maintain the balance between supply and demand. Nevertheless, market participants can assist in managing the appropriate balance of supply when there is surplus baseload generation. Ontario, IESO forecasts the hours in each day where an SBG condition is expected to occur. This enables the respective market participants to make decisions about scheduling their resources.<sup>20</sup>

Some Balancing Authority Area Operators have implemented interchange schedule operating practices known informally as “firm within the hour.” In contrast, most Balancing Authorities allow a transmission user to adjust interchange schedules intra-hour to manage their energy imbalance, subject to reasonable limits. For Balancing Authorities which are firm on hourly energy scheduling, Balancing Authorities may require increased load-following reserves or other balancing resources to offset the wind output scheduling error during an entire operating hour. Some research has suggested that this operating practice may contribute to increased capacity requirements for Balancing Authorities.<sup>21</sup> In addition, Balancing Authorities may not have access to sufficient ancillary services due to transmission limitations or generation characteristics on their own or in neighboring systems.

NERC requires organizations to meet its applicable Reliability Standards which have been approved by FERC or Federal/Provincial regulators. Within NERC’s Standards, there currently are no requirements on the suitable timeframe to schedule resources, rather that each Balancing Authority Area judge the best course of action based on their own character and available resources. The IVGTF suggests that those Balancing Authorities facing significant integration of variable resources consider studying the benefits of sub-hourly scheduling to manage the integration of variable generation. Depending on the current or projected Balancing Authority system characteristics, assuming sufficient transmission is available, there may be benefits to intra-hour interchange scheduling, in the form of reduced ancillary service requirements, more flexibility and ability to manage the variability, while meeting NERC’s Reliability Standards.

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 a growing amount of distributed wind energy, most wind seems likely to be installed on the transmission system.

From a control room and forecasting point of view, the concern with variable generation on the distribution system is the current 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 for operators. 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 the 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.

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<sup>20</sup> More information on SBG forecasting in Ontario is available via following Web link:  
<http://www.ieso.ca/imoweb/marketdata/sbg.asp>

<sup>21</sup> Kirby, B. and Milligan, M., *Capacity Requirements to Support Inter-Balancing Authority Area Wind Delivery*. Technical Report NREL/TP-550-46274, July 2009.

## 4. Survey of Regional Ancillary Products

### A. Frequency Response

All resources plus spinning reserves must be synchronized and generators are required to be frequency responsive. ERCOT, IESO, NYISO, MISO & PJM's frequency response is not a standalone ancillary product. WECC is developing a Frequency Responsive Reserve (FRR) to share the total obligation among respective BA proportion to WECC's BA's load and generation.

### B. Regulation

Regulating Reserve is the amount of Spinning Reserve responsive to Automatic Generation Control (AGC). There is no requirement on a BA to carry a fixed requirement of regulating reserves. Response times vary for IESO ranging from tens of seconds to a few minutes. Regulating Reserves are driven by many factors, For example, within PJM; regulation is supplied by Regulation Class within its electrical boundaries.

PJM Regulation is scheduled in the following ways:

- The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the on-peak (0500 – 2359) and off-peak (0000 – 0459) periods of the day.
- The PJM RTO on-peak Regulation Requirement is equal to 1 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1 percent of the forecast valley load for the PJM RTO for the day.
- The requirement percentage may be adjusted by the PJM Interconnection, if the adjustment is consistent with the maintenance of NERC control standards.

PJM regulation resource owners will receive two regulation signals:

- **AReg** – Assigned Regulation: This is the assigned hourly regulation quantity (MW) that is cleared from the regulation market system. This value, although typically static for the hour, will be sent on a 10-second scan rate.

#### **Frequency Response**

*The ability of a system or elements of the system to react or respond to a change in system frequency.*

#### **Regulation**

*Continuous response (10 seconds to several minutes) of reserves under Automatic Generation Control (AGC) that are deployed to correct minute-to-minute deviations in system frequency or return system frequency to the desired range following a system disturbance. Regulation is a FERC defined ancillary service, which is obtained through hourly markets in many locations.*

#### **Spinning Reserve**

*Generation (or responsive load) that is poised, ready to respond immediately, in case a generator or transmission line fails unexpectedly. Spinning reserve begins to respond immediately and must fully respond within ten minutes (or potentially 15 minutes according to the revised NERC DCS requirement). Enough contingency reserve (spinning and non-spinning) must be available to deal with the largest failure that is anticipated.*

#### **Non Spinning Reserve**

*Similar to spinning reserve, except that response does not need to begin immediately. Full response is still required within 10 minutes, however.*

- **RegA** – Real-time instantaneous resource owner fleet regulation signal (+/- MW): This signal is used to move regulating resources in the owner's fleet within the fleet capability (+/- TReg). This value will be sent on a 2-second scan rate.

### *C. Spinning Reserve*

- ERCOT maintains a 10-minute reserve service of at least 2300 MW to 2800 MW.
- IESO spinning reserve is 25 percent of the 10 minutes operating reserve on the system. In addition, IESO procures 30-minute reserve based on the largest contingency plus half of the second largest contingency.
- MISO must carry 40 percent of their Contingency Reserve requirement as spinning reserve and must be restored within 90-minutes.
- NYISO carry at least 50 percent of the 10-minute reserve as unused reserve capacity.
- PJM as an RTO have specific Synchronized Reserve Zone Requirements for two zones,
  - Reliability First Corporation (RFC) Synchronized Reserve Zone and
  - Southern Synchronized Reserve Zone
- SPP carries at least 50 percent of the Contingency reserve as spinning reserve.
- WECC carries at least 50 percent of combined spinning and non spinning reserve that cover the Disturbance Control Standard and must be replenished within 105 minutes following a contingency.

### *D. Non-Spinning Reserve*

- ERCOT calculates non-spinning reserve for each hour of the day each month. This reserve is a 30-minute product provided by the Off-Line Generator Resource capacity, and Loads acting as a Resource in response to loss-of-Resource contingencies.
- NYISO's non-synchronized resource capacity such as hydro, pumped storage hydro, and quick start combustion generation including load reductions can be loaded in 10 minutes or less.
- PJM is planning to add 10--minute non-synchronized reserves into the existing ancillary service markets in 2010.
- SPP's non-spinning reserve is also called Ready Reserves, some or all may not be connected to the interconnected network but applicable to meet the NERC DCS requirements.
- NYISO have 30 minutes operating reserve requirement, which is equal to one-half of the 10 minute needed to cover the most severe contingency.
- WECC is required to carry 50 percent of its contingency reserve obligation

### *E. Other*

- **PJM:** supplemental reserve is tracked and reported in real-time via Instantaneous Reserve Checks (IRC).
- **SPP:** future markets will include spin, supplemental, regulation up and regulation down products aimed at a consolidated BA.

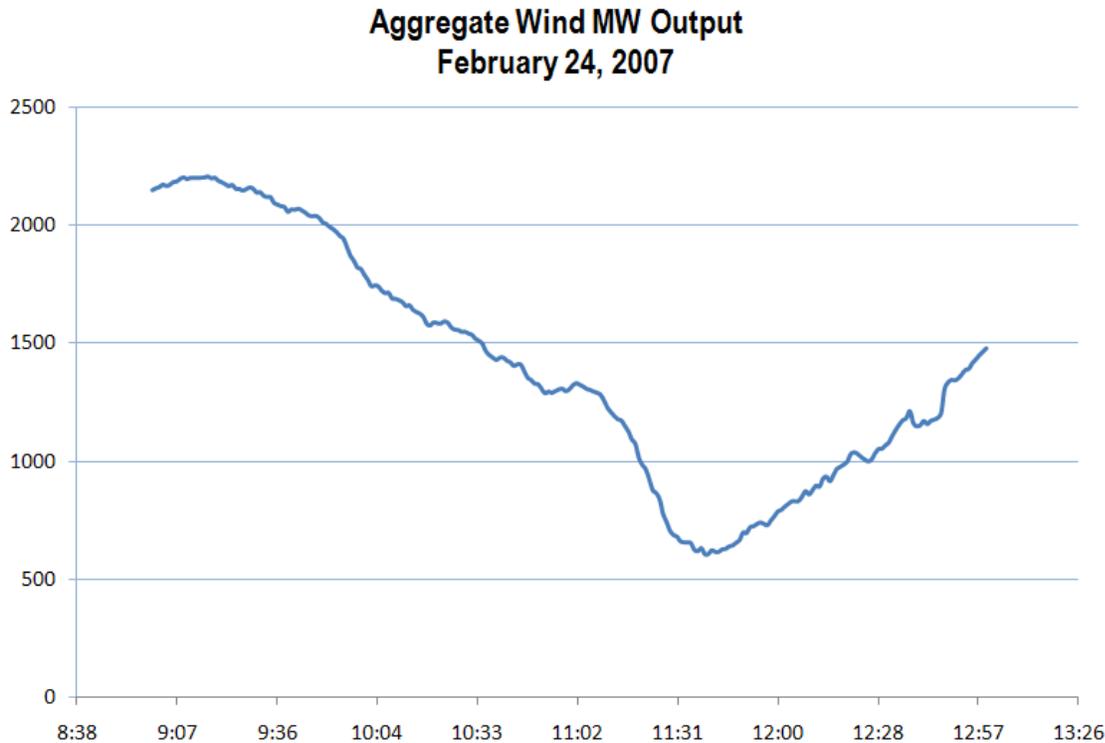
- **WECC:** uses the Load Responsibility Calculation; transfer of Contingency reserve responsibility between BAs. BA's are responsible to increase energy (contingency reserve) export, and decrease import and vice versa.
- **IESO:** real time markets for synchronized operating spinning reserve are available, which is available within 10 minutes, while non-synchronized operating reserve is available within 10 minutes; 30-minute reserve (synchronized and non-synchronized) are available within 30 minutes with having supplemental reserves, for Reliability Must-Run Resources/Contracts:
  - IESO can call in specific entities excluding non-dispatchable load, other than contracted ancillary services to maintain the reliability of the IESO controlled grid.
  - IESO adheres to the requirements set forth by the Northeast Power Coordinating Council (70 percent base load).

## 5. Specific Balancing Authority Area Questions

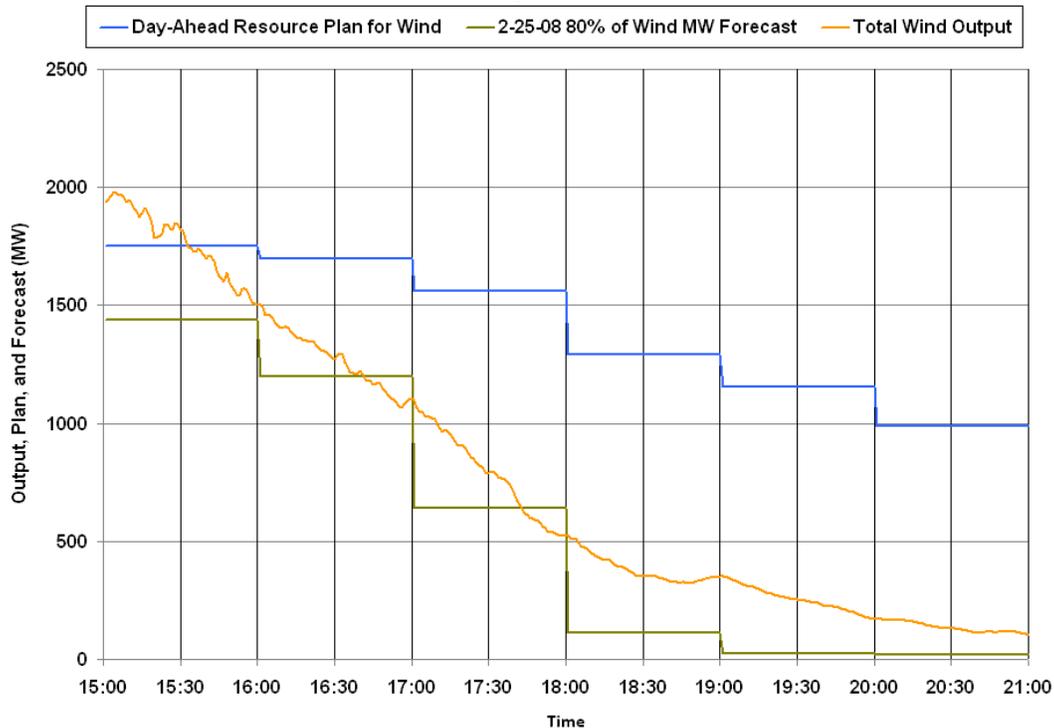
### A. Separate Ancillary Services to Supplement Loss of Wind Generation

Large wind events are similar to conventional generation contingencies in that they are big, relatively infrequent and can impact the reliability of the bulk power system reliability. They differ from conventional generation contingencies in that large wind events are comparatively slow and wind-energy output forecasting can provide system operators with some warning, enabling them to make preparations and take actions. Figure 5-1 shows two large wind events from 2007 and 2008. In the 2007 event, total wind production dropped by about 1500 MW over two hours. In 2008, the drop was about 1,700 MW over three and a half hours. Both events were smaller than the largest single contingency that ERCOT constantly maintains reserves to deal with: the 2300 MW simultaneous loss of both South Texas nuclear units. NERC Reliability Standards, however, require that contingency reserves should be restored within 105 minutes from the start of an event. Contingency reserves are not designed to deal with something as slow as a drop in wind output which can unfold in a slower time frame than sudden loss of conventional units.

**Figure 5-1: Two large ERCOT Wind Events are slower than Conventional Generation Events**



## February 25, 2008



The power system operator must maintain the generation and load balance. When wind plant output declines, other generation must increase or the load must decline. Load decline could come from the natural daily load cycle. Demand Response or an increase in conventional generation must come from the energy dispatch or ancillary service providers. If there is enough depth in the sub-hourly and hourly energy availability, there would be sufficient flexibility to maintain reliability; the energy dispatch can function normally to balance generation and load. If sufficient response is not available from the energy dispatch, use of ancillary service reserves could be deployed, although this practice is not yet accepted in many areas. In any event, if insufficient reserves are available, then re-dispatch should occur to maintain bulk power system reliability.

The slower response speed of a wind event means that the reserve service would not need to be as responsive as traditional contingency reserves, which rely heavily on the frequency response and ready-to-deploy status from spinning reserves to quickly rebalance the system. Operating reserves for a wind event can likely be brought on line in minutes and in layers to respond to reduced variable generation output. Other ways to provide operating reserve without increasing the spinning reserve requirement come from a variety of resources or demand response, e.g. Demand Response, energy transactions, fast start combustion turbines, and engine-driven plants. Whether such a service should be provided as an ancillary service or via real time energy dispatch, is a reflection of risk tolerances around the depth of supply and the availability of alternative forms available to the Balancing Authority. The more certain the supply or the availability of alternative controls, the less need for a separate defined ancillary service.<sup>22</sup>

<sup>22</sup> Control capability on many modern wind and solar plants can mitigate the ramping effects of wind and solar events.

## **B. Contingency Reserve be used for Loss of Wind Generation**

Given the relatively slow ramp of wind output events compared with loss of large dispatchable resources, it may seldom become necessary to deploy contingency reserves due to loss of wind generation. However, there are operating conditions such as tripping of wind plants at their point of interconnection that closely compare to the loss of conventional resources. In such circumstances, there should be little controversy if the Balancing Authority operator deploys contingency reserves.

Further, if the bulk power system is in distressed condition, for example through a declared Energy Emergency Alert, and loss of wind output worsens those conditions, it should not be objectionable to deploy contingency reserves in order to maintain reliability. However, various markets and regional contingency reserve sharing groups have business practices and rules regarding deployment of reserves in response to wind variability.

***Recommendation 1: Each region or reserve-sharing group should permit Contingency Reserve deployment under imbalance energy circumstances made more likely with the increasing penetration of renewables.***

## **C. Balancing Authorities should monitor a their Reserve Levels to meet Down-Ramp and Up-Ramp Conditions**

Most new wind plants can be dispatched to limit ramp rates with the ability to curtail output so wind energy does not impact reliability by forcing it the bulk power system. However, unless these capabilities are stipulated at the time of interconnection, the capability may not be available for use by the system operators.

***Recommendation 2: The task team recommends that the generator interconnection requirements be modified to require this dispatchable control capability interfaced with the grid operator for all new variable generation resource developments.***

Wind is generally the lowest marginal cost power being produced. Within the bounds of meeting bulk power system reliability requirements, it usually makes economic and societal sense to operate the power system to maximize use of the lowest marginal cost generation including wind and other renewable resources.<sup>23</sup> The least-cost unit commitment and economic dispatch is likely one that accommodates wind variability and unpredictability by incorporating flexibility into the conventional generation mix and including down ramping capability. Incorporating down ramping into the day-ahead unit commitment decision should be a probabilistic economic decision, however, and not a reliability requirement.

***Recommendation 3: Regional market operators and other grid operating entities should develop the ability to consider transmission service by prioritizing variable resources when allocating curtailment responsibility to variable output resources during reliability-limited operating conditions.***

## 6. Reliability Standard Input Recommendations

### *BAL-001-0.1a — Real Power Balancing Control Performance*

**Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

**Requirements:** Meet Control Performance Standard (CPS) 1&2.

**Recommendation:** *Increased Balancing Authority collaboration reduces cost overall, and is valuable for integration of variable generation*

### *BAL-002-0 Disturbance Control Performance (also the WECC version)*

**Applicability:** BA, Reserve Sharing Groups, Regional Reliability Organization (RRO)

**Purpose:** The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to use its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

**Requirements:** Specify contingency reserve policies including the procedure for applying Contingency Reserves in practice. Activate reserves to meet DCS. Meet DCS and restore reserves 15-minute default response time and 90 minute default restoration time.

**Recommendation:** *The standard drafting team should consider if Contingency Reserves can be used to meet DCS requirements for wind-related events. Reserve calculation procedures should be updated to take into account variable energy resource events, including ramping events that are much slower than the instantaneous contingency events caused by conventional generators and transmission failures. This could impact recommendations for Contingency Reserve Policies, DCS, DCS response time, and DCS recovery time.*

**Alternatively:** *The current BAL-002 and DCS do not apply to variable energy resource events because they are too slow. There is no need to change BAL-002 due to variable energy resource integration. Balancing Authorities would need to deal with the risk of tail events with their own resources – or with different resources than the current DCS resources. Ultimately, it would be more efficient to mitigate the risk of rare tail events by using pooled reserves, especially in high penetration scenarios.*

**Action:** *IVGTF2-3 should collaborate with the Standards Drafting Team to establish another requirement to accommodate variable energy resources and their tail events.*

**Applicability:** RC, BA, TOP, TSP, GOP, LSE, PSE

**Purpose:** 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.

**Requirements:** RC shall monitor its area, evaluate and mitigate IROLs and SOLs, ensure adequate operating reserves, disseminate info, monitor frequency, and be aware of SPS status. Many requirements for SOLs and IROLs include studies, disseminating information, and returning the system within required parameters in 30 minutes or less.

***Recommendation:** A NERC Standard is required to communicate variable generation derates due to turbine outage conditions and plans. Currently issues may arise if part of a wind plant is out-of-service operators are not aware of the number of turbines unavailable and duration of the forced or planned outage.*

#### **TOP-002-2&A — Normal Operations Planning**

**Applicability:** BA, TOP, GOP, LSE, TSP

**Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

**Requirements:** Plan for normal operations and contingencies and communicate these plans (when confidentiality agreements allow).

***Recommendation:** The standard should be enhanced to provide guidance on incorporation of variable energy resource events into the planning process.*

#### **TOP-006-1&2 — Monitoring System Conditions**

**Applicability:** BA, TOP, GOP, RC

**Purpose:** To ensure critical reliability parameters are monitored in real-time.

**Requirements:** GOP must tell BA & TOP generator status. Watch the system. Predict near-term load from weather.

***Recommendation:** Expand R4 to require similar information and prediction of variable generation output:*

*R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load and variable generation patterns are available to predict the system's near-term load and variable generation pattern.*

## Appendix I: Regional Practices for Ancillary Services

The survey enabled the comparison of regional practices and procedures regarding ancillary services. This set a firm foundation for the recommendations.

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
<b>Frequency Response: 0 – 30 seconds</b>	
<b>ERCOT</b>	Primary frequency response is not an Ancillary Service Market Product. All online Generation Resources must have their turbine governors in service and unblocked.
<b>IESO &amp; NYISO</b>	Frequency response is not a stand-alone Ancillary Service product.
<b>PJM</b>	Frequency response is not a stand-alone Ancillary Service product. All resources providing spinning reserve must be synchronized to the grid and must be frequency responsive. The PJM RTO operates in accordance with NERC Resource and Demand Balancing (i.e. BAL) standards to ensure its capability to use reserves to balance resources and demand in real-time and to return Interconnection frequency within defined limits following a Repairable Disturbance.
<b>WECC</b>	Frequency response is not a stand-alone Ancillary Service product. All resources providing spinning reserve must be synchronized to the grid and must be frequency responsive.  The WECC is in the process of developing Frequency Responsive Reserve (FRR) criteria. At this point, it is not clear if this criteria would replace spinning reserve or if FRR would be a subset of spinning reserve. The current proposal is to base FRR on a NERC category C event. The proposal is to share the total WECC FRR obligation among the respective BA proportional to a BA's load and generation.
<b>Regulation: 4 seconds – 5 minutes</b>	
<b>ERCOT</b>	Regulation is deployed through ERCOT's EMS system. The MW requirement for each hour of the day is determined monthly. The amount of MWs procured is based on the amount historically deployed and the amount of time in which regulation service was exhausted. Additionally, the study also considers how much wind generation resource capacity has come into the system since the historical deployments took place.
<b>IESO</b>	The IESO contracts for the regulation service. Regulation Service acts to match total system generation to total system load (including transmission losses) and helps correct variations in power system frequency. Response times may range from tens of seconds to a few minutes. This service is currently provided by contracted generation facilities with automatic generation control (AGC) capability, which permits them to vary their output in response to signals sent by the IESO. Terms and conditions of contract include: <ul style="list-style-type: none"> <li>➤ Minimum of ±100 MW of automatic generation control (AGC) must be scheduled at all times</li> <li>➤ Minimum overall ramp rate requirement for Ontario is 50 MW/minute</li> </ul>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
<b>NYISO</b>	<p>Regulating reserve is the online reserve available for control via Automatic Generation Control and shall be sufficient to meet NERC control performance standards.</p> <p>Regulation is dispatched through a BA’s Energy Management system every 6 seconds.</p> <p>The regulation requirement is determined for each hour of the day for each month of the year.</p>
<b>MISO</b>	<p>Regulation is online reserve that is responsive to a BA’s Automatic Generation Control signal. There is no requirement on a BA to carry a set amount of regulating reserve, however, a BA is required to carry sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the BA to meet NERC’s Control Performance Criteria.</p> <p>Regulation is dispatched through a BA’s Energy Management system every 4 seconds.</p>
<b>PJM</b>	<p>Regulation refers to the control action that is performed to correct for load changes that may cause the power system to operate above or below 60 Hz.</p> <p>Regulation for the PJM RTO is supplied by Regulation Class from resources that are located within the metered electrical boundaries of the PJM RTO. Regulation is scheduled in the following ways:</p> <ul style="list-style-type: none"> <li>➤ Self-Scheduled Resources</li> <li>➤ PJM RTO Regulation Market</li> <li>➤ The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the on-peak (0500 – 2359) and off-peak (0000 – 0459) periods of the day.</li> <li>➤ The PJM RTO on-peak Regulation Requirement is equal to 1 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1 percent of the forecast valley load for the PJM RTO for the day.</li> <li>➤ The requirement percentage may be adjusted by the PJM Interconnection, if the adjustment is consistent with the maintenance of NERC control standards.</li> </ul> <p>PJM regulation resource owners will receive 2 regulation signals:</p> <ul style="list-style-type: none"> <li>➤ AReg – Assigned Regulation. This is the assigned hourly regulation quantity (MW) that is cleared from the regulation market system. This value, although typically static for the hour, will be sent on a 10-second scan rate.</li> <li>➤ RegA – Real-time instantaneous resource owner fleet regulation signal (+/- MW). This signal is used to move regulating resources in the owner’s fleet within the fleet capability (+/- TReg). This value will be sent on a 2-second scan rate.</li> </ul>
<b>SPP</b>	<p>Regulating Reserve is an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin. The BA minimum Regulating Reserve is equal to an amount necessary to maintain compliance with control performance standards while scheduling all Contingency Reserves to other BAs.</p>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
<b>WECC</b>	<p>Regulation is spinning reserve that is responsive to a BA’s Automatic Generation Control signal. There is no requirement on a BA to carry a set amount of regulating reserve, however a BA is required to carry sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the BA to meet NERC’s Control Performance Criteria.</p> <p>Regulation is dispatched through a BA’s Energy Management system every 4 seconds.</p>
	<p><b>Spinning Reserve: 10 mins – 105 mins</b></p>
<b>ERCOT</b>	<p>ERCOT maintains a 10-minute reserve service of at least 2300 MW. This is for normal conditions and can go up to 2800 MW. Demand-side resources can provide up to 50 percent of this MW requirement. It may be provided from the following:</p> <ul style="list-style-type: none"> <li>➤ Unloaded Generation Resources that are on-line;</li> <li>➤ Resources controlled by high set under-frequency relays; or</li> <li>➤ Direct Current (DC) tie-line response. The DC tie-line response must be fully deployed within fifteen seconds on the ERCOT system after the under frequency event.</li> </ul> <p>These reserves are maintained by ERCOT to restore the frequency of the ERCOT system within the first few minutes of an event that causes a significant deviation from the standard frequency. Load-following energy and non-spin reserves will be deployed as practicable and if necessary to minimize the use of the 10-minute reserves.</p>
<b>IESO</b>	<p>The IESO administers markets for three classes of Operating Reserve (OR): 10-minute spinning, 10-minute non-spinning and 30-minute OR. Ten-minute spinning and non-spinning OR must be provided by resources whose energy can be made available within 10-minutes of the contingency to restore the balance between supply and demand. Ten-minute spinning OR can be offered by generators that are actually synchronized to the power grid. Thirty-minute OR can be offered by spinning or non-spinning resources that are available to provide energy within 30 minutes of activation.</p> <p>The IESO created an OR market to efficiently purchase OR from market participants and subsequently activate it, when needed, to quickly restore the balance between supply and demand. Market participants can offer OR to the IESO-administered markets at the same time that they bid or offer energy (to offer operating reserve, there must be an energy bid or offer of at least as many megawatts).</p> <p>Ten minutes operating reserve requirements are based on the largest single recognized event (contingency) on the system. Ten-minute spinning reserve is normally 25 percent of the 10-minutes OR (single largest contingency) on the system. Note that as per Northeast Power Coordinating Council Inc. (NPCC Inc.) criteria, 100 percent of an area's 10-minute reserve requirement shall be synchronized reserve except as mentioned below. An area is required to adjust its synchronized reserve requirement based on its ability to recover from reportable events within fifteen minutes. This synchronized reserve requirement may be decreased to a minimum of 25 percent of the 10-minute reserve requirement based upon the area's past</p>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
	<p>performance in returning its Area Control Error (ACE) to pre-contingency values, or to zero, within fifteen minutes. Specific additional requirements of NPCC operating reserve criteria (A-06) are available via following link:  <a href="http://www.npcc.org/documents/regStandards/Criteria.aspx">http://www.npcc.org/documents/regStandards/Criteria.aspx</a></p> <p>In addition, the IESO procures 30-minute reserves based on the largest contingency plus half of the second largest contingency that could occur under a given IESO-controlled grid operating configuration. IESO, Ontario is also part of a shared activation of reserve group which includes PJM, NYISO, NBSO and ISONE. More information on IESO's/Ontario operating reserve (spinning and non-spinning) requirements is available via following link:  <a href="http://www.ieso.ca/imoweb/marketsAndPrograms/op_reserve.asp">http://www.ieso.ca/imoweb/marketsAndPrograms/op_reserve.asp</a></p>
<b>NYISO</b>	<p>Synchronized Operating Reserve – At least one-half of the 10-minute operating reserve will consist of unused resource capacity, which is synchronized and ready to achieve claimed capacity including load reductions achieved by reducing consumption, or resource capacity, which can be made available by curtailing pumping hydro units or canceling energy sales to other systems.</p> <p>The 10-minute operating reserve requirement shall be the greater of the operating capacity loss caused by the most severe contingency observed under normal transfer criteria, or the largest energy loss caused by the cancellation of an interruptible energy purchase from another system.</p>
<b>MISO</b>	<p>Online generation resources able to be loaded within the DCS recovery period. Regulating Reserves in excess of requirement may be used for Spinning Reserves. BA must carry 40 percent of their Contingency Reserve requirement as Operating Reserve – Spinning.</p> <p>Operating Reserve – Spinning must be fully restored within 90 minutes of the end of the DCS recovery period, which is 15 minutes from the initial event.</p>
<b>PJM</b>	<p>Synchronized Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and must be provided by equipment electrically synchronized to the system.</p> <p>The RTO will be arranged into two (2) zones. All companies within PJM, excluding the SERC companies, are part of the ReliabilityFirst Corporation (RFC) reliability region and will thus be grouped together into a single synchronized reserve zone. The SERC companies are part of a separate reserve sharing agreement and therefore, comprise a second synchronized reserve zone. The RFC Synchronized Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. The requirement will be defined as the greater of the ReliabilityFirst Corporation (RFC) imposed minimum</p>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
	<p>requirement or the largest contingency on the system.</p> <p>The Southern Synchronized Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR, minus the available 15-minute quick start capability within the Southern Synchronized Reserve Zone. Synchronized market clearing is a joint optimization between regulation and Synchronized reserves. The goal of the optimization is to minimize the total cost of producing energy, regulation, and Synchronized reserve. Resources cannot be committed for both Tier 2 Synchronized and regulation during the same hour</p>
<b>SPP</b>	<p>Spinning Reserve is that unloaded Operating Capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation. The Spinning Reserve allocated to any generating unit shall not exceed the amount of capacity increase that will be realized by prime-mover governor action due to a drop in frequency to 59.5 Hertz (less than or equal to 16.7 percent of unit capability at a 5 percent droop setting). At least half of the Contingency Reserve shall be Spinning Reserve.</p>
<b>WECC</b>	<p>A BA is required to carry Spinning Reserve equivalent to 50 percent of its <i>Contingency Reserve</i> obligation.</p> <p>Contingency reserve is an amount of spinning and non-spinning reserve, sufficient to meet the Disturbance Control Standard and shall be at least the greater of:</p> <ol style="list-style-type: none"> <li>(1) The most severe single contingency (at least half of which must be spinning reserve); or</li> <li>(2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve).</li> </ol> <p>For generation-based reserves, only the amount of unloaded generating capacity that can be loaded within 10-minutes of notification can be considered as spinning reserve.</p> <p>Spinning reserve must be replenished within 105 minutes following a contingency. A BA must have documentation that it maintained 100 percent of minimum Spinning Contingency Reserve required based upon data averaged over each clock hour except within the first 105 minutes following an event requiring the activation of Contingency Reserves.</p>

**Table A-1: Summary of Ancillary Services**

Regions	Time Frame
<b>Non Spinning Reserve: 10 – 105 minutes</b>	
<b>ERCOT</b>	<p>Like Regulation, the MW requirement for non-spinning reserves is calculated for each hour of the day each month. Historical wind forecast errors and load forecast errors are used in determining the MW values.</p> <p>Non-spinning reserve service is a 30 minute product and is provided by:</p> <ul style="list-style-type: none"> <li>➤ Off-line Generation Resource capacity, or reserved capacity from on-line Generation Resources, capable of being ramped to a specified output level within 30 minutes; or</li> <li>➤ Loads acting as a Resource that are capable of being interrupted within 30 minutes and that are capable of running (or being interrupted) at a specified output level for at least 1 hour.</li> </ul> <p>Deployed for the Operating Hour in response to loss-of-Resource contingencies, load forecasting error, or other contingency events on the ERCOT System.</p>
	<p>Nonsynchronized Ten Minute Operating Reserve – The remainder of the 10-minute operating reserve may be composed of nonsynchronized resource capacity such as hydro, pumped storage hydro, and quick start combustion generation including load reductions achieved by starting generation, which can be synchronized and loaded to claimed capacity in 10 minutes or less.</p> <p>The 10 minute operating reserve requirement shall be greater of the operating capacity loss caused by the most severe contingency observed under normal transfer criteria, or the largest energy loss caused by the cancellation of an interruptible energy purchase from another system</p>
<b>MISO</b>	<p>Off-line generation able to be loaded or Interruptible Load able to be removed within the DCS recovery period.</p> <p>Spinning reserve in excess of requirement may be used for Supplemental</p>
	<p>Nonsynchronized Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and is provided by equipment not electrically synchronized to the system.</p> <p>The resources that generally qualify in this category are currently shutdown run-of-river hydro, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle, diesels and interruptible demand resources.</p> <p>PJM must schedule sufficient Primary Reserves (including synchronized reserves and nonsynchronized reserves) to satisfy the ReliabilityFirst (RFC) and VACAR requirements. RFC Primary Reserves shall not be less than the largest contingency. RFC Primary Reserves must be made up of at least 50 percent Spinning Reserves. No more than 25 percent of RFC</p>
<b>PJM</b>	

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
	<p>Primary Reserves should be interruptible load. (Standard BAL-002-0, BAL-002-RFC-02).</p> <p>VACAR Primary Reserve Requirements are determined annually, which is 431 MW. PJM triggers the Primary Reserve Emergency Procedures on the Mid-Atlantic Control Zone based on a Primary Reserve Requirement of 1700 MW due to potential deliverability issues. Primary Reserve Requirements for the RFC portion of the PJM footprint is 150 percent of the largest generator.</p> <p>PJM is planning to add the 10-min nonsynchronized reserves into the existing ancillary service market in 2010.</p>
<b>SPP</b>	<p>Non-Spinning/Supplemental Reserves are called Ready Reserves in SPP. Ready Reserve is that the amount of Operating Capacity or the equivalent, some or all of which may not be connected to the interconnected network but which can be connected and fully applied to meet the NERC DCS requirements</p> <p>Acceptable types of Ready Reserves:</p> <ul style="list-style-type: none"> <li>➤ The amount of Operating Capacity connected to the bus that will not be realized by prime-mover governor action. The realization of this capacity may require the governor speed level to be reset.</li> <li>➤ That portion of fast starting generating capacity at rest, such as hydroelectric, combustion turbines, and internal combustion engines as prime movers that can be started and synchronized.</li> <li>➤ Operating Capacity that can be realized by increasing boiler steam pressure, by removing feedwater heaters from service, and/or by decreasing station power use.</li> <li>➤ Operating Capacity and contingency reserve, provided firm transmission has been purchased, being held available under contract by another Balancing Authority above its own operating reserve requirements and available on call</li> <li>➤ Interruptible or curtailment of loads under contract.</li> <li>➤ Power deliveries that can be recovered provided a clear understanding exists between the transacting parties to avoid both parties crediting their respective operating reserves by this transaction.</li> <li>➤ Generating units operating in a synchronous condenser mode.</li> <li>➤ Interruptible pumping load on pumped hydro units.</li> <li>➤ Operating Capacity made available by voltage reduction. The voltage reduction shall be made on the distribution system and not on the transmission system.</li> <li>➤ Operating Capacity that can be fully applied from a change in the output of a High Voltage Direct Current terminal.</li> </ul>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
<b>NYISO</b>	<p>The thirty (30) minute operating reserve portion of the NYISO’s operating reserve requirement is that portion of unused resource capacity or interruptible load which can and will be made fully available as promptly as possible, but in no more than thirty (30) minutes.</p> <p>The thirty (30) minute operating reserve requirement shall be equal to one-half of the ten (10) minute operating reserve necessary to replace the operating capacity loss caused by the most severe contingency observed under normal transfer criteria.</p>
<b>WECC</b>	<p>A BA is required to carry Non-Spinning Reserve equivalent to 50 percent of its Contingency Reserve obligation. Non-Contingency reserve does not have to be synchronized to the grid.</p> <p>For generation-based reserves, an off-line resource must be able to synchronize to the grid and generate up to its awarded Non-Spinning Reserve capacity within 10-minutes.</p> <p>Acceptable types of non-spinning reserve:</p> <ul style="list-style-type: none"> <li>➤ Load which can be interrupted within 10 minutes of notification;</li> <li>➤ Interruptible exports;</li> <li>➤ On-demand rights from other Bas;</li> <li>➤ Spinning reserve in excess of requirement; and</li> <li>➤ Off-line generation that qualifies as non-spinning reserve</li> </ul>
<b>Other</b>	<p><b>ERCOT:</b> Primary frequency response is not an Ancillary Service Market Product. All online Generation Resources must have their turbine governors in service and unblocked.</p> <p><b>NYISO:</b> The thirty (30) minute operating reserve portion of the NYISO’s operating reserve requirement is that portion of unused resource capacity or interruptible load which can and will be made fully available as promptly as possible, but in no more than thirty (30) minutes. The thirty (30) minute operating reserve requirement shall be equal to one-half of the ten (10) minute operating reserve necessary to replace the operating capacity loss caused by the most severe contingency observed under normal transfer criteria.</p> <p><b>MISO:</b> Frequency Response is not a stand-alone Ancillary Service.</p> <p><b>PJM:</b> Supplemental Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within a 10-30-minutes interval following the request of the PJM dispatcher. Resources providing Supplemental Reserve need not be electrically synchronized to the system.</p>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
	<p>In PJM, the supplemental reserves are cleared in day-ahead scheduling reserve market:</p> <ul style="list-style-type: none"> <li>➤ Voluntary, offer-based market for 30-minute reserve that can be provided by both Generation and Demand Resources.</li> <li>➤ Market is designed to clear existing supplemental (operating) reserve requirements as defined by RFC/NERC.</li> <li>➤ Day-ahead, forward market that clears simultaneously with day-ahead market.</li> <li>➤ Costs of Supplemental Reserve Market will be allocated to real-time load ratio share.</li> </ul> <p>While MAIN and ECAR reserve definitions center around 10-minute reserves, supplemental reserve is tracked and reported in real-time for the entire PJM footprint via Instantaneous Reserve Checks (IRC).</p> <p>It is still under discussion by stakeholders whether PJM needs to add supplemental reserve as another product to the existing A/S market.</p> <p><b>SPP:</b> In the future market design, SPP is expected to be a consolidated BA.</p> <p>The design currently includes the definition of ‘Reserve Zones’ used to ensure deliverability with minimum and maximum Operating Reserve requirements in each zone.</p> <p>The SPP Future Market, as contemplated, will include spin, supplemental, regulation up, and regulation down products.</p> <p>The SPP CBA will set the system requirements for regulation up, regulation down, spinning reserves and supplemental reserves.</p> <ul style="list-style-type: none"> <li>➤ MP obligations are load ratio share of system requirements.</li> <li>➤ MP has the option to supply its own obligation or purchasing from market.</li> </ul> <p><b>WECC:</b> Should the IVGTF be looking at a separate Ancillary Service to supplement loss of wind generation? Should contingency reserve be used for loss of wind generation?</p>
	<p><b>Ancillary Services</b></p> <p><b>WECC</b> - The current WECC Contingency Reserve requirement represents a holistic approach to carrying Contingency Reserves for the entire Western Interconnection. The Load Responsibility calculation is used to “transfer” Contingency Reserve responsibility between BAs. Energy with associated Contingency Reserve can be exported and imported between Balancing Authority Areas. However, if Contingency Reserve is associated by agreement with the energy transaction, the responsibility for the Contingency Reserve obligation will remain with the Source BA. In other words, the BA exporting energy that has associated</p>

Table A-1: Summary of Ancillary Services

Regions	Time Frame
	<p>Contingency Reserve would increase its “Load Responsibility” by the amount of the energy being exported. The BA importing the energy has the ability to reduce its “Load Responsibility” by the same amount. This has the effect of maintaining the appropriate amount of Contingency Reserve on a Western Interconnection wide basis.</p> <p><b>Ontario</b> - Real-time markets for synchronized operating (spinning) reserve are available within 10 minutes, while non-synchronized operating reserve is available within 10 minutes; 30-minute reserve (synchronized and non-synchronized) are available within 30 minutes with having supplemental reserves.</p> <p>Requirements to ensure the availability of sufficient <i>generation capacity</i> and <i>ancillary services</i> to the <i>IESO-administered markets</i> are set forth as per market rules chapter 5, section 4. See section 4 in: <a href="http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5.pdf">http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5.pdf</a></p> <p>Performance standards for ancillary services are available via following Web link: <a href="http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5appx.pdf">http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter5appx.pdf</a></p> <p><b>Additional Contracts for Ancillary Services</b></p> <p>In order to ensure the reliable operation of the power system, the IESO contracts for additional four ancillary services.</p> <p>These are:</p> <ul style="list-style-type: none"> <li>➤ black-start capability;</li> <li>➤ emergency demand response program (EDRP);</li> <li>➤ regulation service; and</li> <li>➤ reactive support and voltage control service.</li> </ul> <p>Ancillary service costs are borne by loads. The IESO is committed to a fair, competitive process to award these contracts. Information on ancillary services contracts is available via following Web link: <a href="http://www.ieso.ca/imoweb/marketdata/ancilSrvContracts.asp">http://www.ieso.ca/imoweb/marketdata/ancilSrvContracts.asp</a></p> <p><b>Reliability Must-Run Resources/Contracts</b></p> <p>The IESO may need to call on specific registered facilities, excluding non-dispatchable load facilities, to maintain the reliability of the IESO-controlled grid whenever sufficient resources for the provision of physical services, other than contracted ancillary services, are not otherwise offered in the IESO-administered markets. Such applicable registered facilities are referred to as reliability must-run resources and shall be procured through reliability must-run contracts</p> <p><b>Wind and Ancillary Services Market in Ontario</b></p> <p>Wind cannot offer into ancillary service markets in Ontario.</p>

**Table A-1: Summary of Ancillary Services**

<i>Regions</i>	<i>Time Frame</i>
	<p><b>Northeast Power Coordinating Council Inc (NPCC) Operating Reserve Criteria</b>                      The Northeast Power Coordinating Council, Inc. (NPCC) is the cross-border regional entity and criteria services corporation for northeastern North America. Access to NPCC can be found at via the following Web link: <a href="http://www.npcc.org/">http://www.npcc.org/</a>.</p> <p>The IESO adheres to the requirements set forth in the NPCC operating reserve criteria document A-06.</p> <p>Background of NPCC operating reserve criteria is outlined below.</p> <p>In the continuous operation of electric power systems, operating capacity is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie line power flow. The operating capacity in excess of that required for actual load is commonly referred to as operating reserve. This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of operating reserve. The objective is to facilitate a high level of reliability in the NPCC region that is, as a minimum, consistent with the Operating Policies and Standards specified by the North American Electric Reliability Council (NERC). The requirements of NPCC operating reserve criteria (A-06) are available via following Web link: <a href="http://www.npcc.org/documents/regStandards/Criteria.aspx">http://www.npcc.org/documents/regStandards/Criteria.aspx</a></p>

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