

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Integration of Variable Energy Resources)

Docket No. RM10-11-000

COMMENTS OF ISO NEW ENGLAND INC.

ISO New England Inc. (“ISO”)¹ submits these comments pursuant to the Notice of Inquiry issued by the Federal Energy Regulatory Commission (“Commission”) on January 21, 2010² (“NOI”) and as published in the Federal Register on January 27, 2010.³

I. EXECUTIVE SUMMARY

In its NOI, the Commission requests comments on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources (“VERs”) into the electric grid to determine whether reforms to existing rules are necessary.⁴ The Commission explains that its objectives are not to “adopt rules that favor one type of supply source over another”; but rather, “to ensure that rates for jurisdictional service are just and reasonable” and “to prevent VERs from facing undue discrimination.”⁵ The Commission also states any reforms

¹ Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets, Services Tariff, FERC Electric Tariff No. 3 (“ISO Tariff”) or in the Participants Agreement among the ISO and the New England Power Pool and any individual Participants (the “Participants Agreement”). The Participants Agreement was accepted by the Commission in ISO New England Inc., et al., 109 FERC ¶ 61,147 (2004). Section II of the ISO Tariff contains the Open Access Transmission Tariff (“ISO OATT”), and Section III of the ISO Tariff contains the Market Rules (“Market Rules”).

² *Integration of Variable Energy Resources*, 130 FERC ¶ 61,053 (2010) (“NOI”).

³ *Integration of Variable Energy Resources*, 75 Fed. Reg. 4316 (January 27, 2010).

⁴ NOI at P 12. *See also id.* at PP 1, 4.

⁵ *Id.* at P 10.

must be “consistent with the need to maintain system reliability in accordance with Reliability Standards.”⁶

To that end, “[t]he Commission requests comments on the impact of integrating an increasing number of VERs”⁷ in seven subject areas:

(1) data and reporting requirements, including the use of accurate forecasting tools; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and, (7) redispatch and curtailment practices necessary to accommodate VERs in real time.⁸

Regarding each of these subject areas, the Commission poses several specific questions. In these comments, the ISO addresses several of those questions and provides the Commission with additional comments and information that the ISO believes will assist the Commission in gaining a more complete picture of the current issues and challenges facing the integration of VERs.

Specifically, in Section IV, the ISO provides a brief overview of the New England Markets and VER participation in those markets as enabled by the existing Market Rules. In that section, the ISO also describes the ISO-led studies to assess the integration of VERs in New England. In particular, the ISO describes the comprehensive wind integration study commissioned by the ISO in 2009 for completion in September 2010. This study is assessing the effects of large-scale wind penetration in New England using statistics and simulation analysis of historical data, including the development of a mesoscale hindcasting model for the New England and Maritime areas that will facilitate the simulation analysis. It also will determine the operational, planning and market impacts of integrating substantial wind generation resources for

⁶ *Id.* at P 11.

⁷ *Id.* at P 12.

⁸ *Id.*

New England, as well as the measures that may be available to the ISO for mitigating any negative impacts while enabling the integration of wind. While the focus of this study is on the integration of wind resources, the most significant category of VERs for New England, the ISO will be evaluating the integration of other VERs, as well.

With this background, in Section V, the ISO addresses the questions posed by the Commission in the NOI. While the existing rules and practices in New England do not present barriers to the integration of additional VERs, the ISO is assessing most of the issues raised by the Commission to determine the impact of integrating a substantial amount of VERs in New England. The results of the study described in Section IV ultimately will inform the region as to the potential system challenges and solutions. It is clearly premature to seek to develop uniform solutions now, before the challenges have been identified.

As the ISO addresses further in Section V:

- While the current system can accommodate an increase in VERs, the forecasting practices that are in place will not be viable practices with a substantial penetration of VERs in New England. However, before transitioning from the existing forecasting practices for VERs to a state-of-the-art forecasting system, the goals, methods and requirements of such a system must be developed, and a plan must be developed for testing and implementation. The ongoing wind integration studies in New England will inform this effort.
- Having both a centralized and decentralized forecasting process encourages the appropriate parties to take responsibility for the roles they play in the power system markets and operations; however, it is essential that the centralized forecasting method be utilized as the primary driver for the reliability commitment within each Balancing Authority Area in order to ensure reliability.
- Implementation of shorter scheduling intervals on external interfaces may be beneficial for VER integration; however, those benefits can only be realized when the variation of the VER output results in a change in the scheduled flow on external interfaces.
- VERs are not required to participate in the Day-Ahead Energy Market in New England. The ISO plans to examine whether VERs should be required to participate in the Day-Ahead Energy Market, particularly those VERs with obligations in the Forward Capacity Market. While a closer examination of the

potential benefits that the use of the DAM may result in is worthwhile, most operational risk can be addressed with the implementation of a robust centralized forecasting regime.

- As a general matter, increasing the geographic footprint of Balancing Authority Areas can be beneficial for the integration of some types of VERs. Larger geographic areas may have a more diverse mix of resources to balance VERs. In New England, for example, a number of different generation technologies are utilized, including flexible combined-cycle gas facilities. The benefits that a larger geographical Balancing Authority Area could provide, however, can only be realized if there are transmission facilities capable of moving power throughout the system.
- Existing reserve and regulation products should provide adequate load/VER following capability under a wide range of typical operating conditions in New England; however, under higher VER penetration, it might be appropriate to increase the amount of reserves and regulation carried. .
- The reactive power requirements established in Order No. 661 should be revisited. VERs should, as much as possible, be treated as any other resource. VERs should be required to meet a reactive power management standard so that they can participate as an equal partner in the power system, with the result that the transmission system can operate reliably even with a high penetration of VERs.

II. IDENTIFICATION OF ISO NEW ENGLAND

The ISO is the private, non-profit entity that serves as the Regional Transmission Organization (“RTO”) for New England. The ISO administers the New England energy markets and operates the regional bulk power system (*i.e.* those facilities located in the New England region) pursuant to the ISO Tariff and operating agreements with the New England transmission owners. In its capacity as the RTO for New England, the ISO has the responsibility to protect the short-term reliability, and plan for the long-term reliability, of the control area, a six-state region that includes approximately 6.5 million businesses and households.

III. COMMUNICATIONS

All correspondence and communications concerning this Answer should be sent to the following persons, who should be added to the official service list, at the addresses shown:

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IV. BACKGROUND

A. Description of Market Design in New England

The New England market design consists of an energy market (*i.e.*, Day-Ahead and Real-Time Energy Markets), the ancillary services markets (*i.e.*, Forward Reserve Market and Regulation Market), and a capacity market (*i.e.*, Forward Capacity Market). Through these competitive wholesale markets, the ISO ensures the availability of electricity to meet the demands of the region. A brief overview of these markets is necessary to provide context for some of the ISO's responses to the Commission's inquiries.

Through the Day-Ahead Energy Market ("DAM") and Real-Time Energy Market ("RTM"), the ISO coordinates the commitment and dispatch of resources. Specifically, in the DAM and RTM, the ISO economically schedules resources to provide energy and ancillary services on the basis of supply offers, bid-in load, submitted external transactions and transmission information. The DAM produces financially binding obligations. Resources generally are committed to operate in real-time consistent with their DAM schedule. To the extent that insufficient resources clear in the DAM to meet the ISO's forecasted real-time load or expected real-time reliability requirements (*e.g.*, local second contingency coverage), the ISO commits additional resources. The RTM is effectively a balancing market. In real-time, the

dispatch and scheduling software co-optimizes the dispatch of resources to provide energy and operating reserves. The ISO also runs the Regulation Market in real-time which schedules resources to provide Regulation services. Dispatch instructions are sent out to all of the resources in the New England Balancing Authority Area, consistent with their offer data and limits and constraints, to meet changing load and ancillary service requirements throughout the Operating Day.

Day-before scheduling and commitment of generation is done on an hourly basis while real-time dispatch is done on five-minute intervals or on demand using a security-constrained economic commitment and dispatch. This approach recognizes transmission constraints in the commitment and dispatch solutions. Both the DAM and RTM generate hourly (RTM rolls up five minute prices) Locational Marginal Prices (“LMP”), which reflect the marginal cost of meeting the next increment of load at a location while respecting transmission constraints. The RTM also produces locational reserve prices by reserve category and system-wide regulation prices. The reserve prices reflect the opportunity cost of re-dispatching the system to maintain reserves. Regulation prices reflect the offer of the marginal resource selected to provide Regulation in an hour.

The ISO also administers a Forward Capacity Market (“FCM”) and a Locational Forward Reserve Market (“LFRM”). The FCM is a forward market for physical resources through which the ISO procures an amount of capacity equal to the Installed Capacity Requirements (“ICR”) for New England three years prior to the time the capacity is needed. The LFRM is the mechanism by which the ISO procures reserve capacity in New England for dispatch during system contingencies.

B. VER Participation in New England

Currently, approximately 745 MW of VERs⁹ are interconnected to the New England Transmission System and are able to participate in the New England Markets. Participation in the New England Markets by VERs is facilitated by the New England Market Rules. Specifically, in New England, all non-Intermittent Power Resources¹⁰ (*i.e.*, *non-VERs*) and external resources with a Capacity Supply Obligation in the FCM are required to participate in the DAM. Intermittent Power Resources (*i.e.*, VERs) are not required to participate in the DAM, but they are permitted to do so. Regardless of whether or not they offer into the DAM, Intermittent Power Resources are not subject to deviation or imbalance charges in the RTM. The Market Rules also allow VERs to participate in the FCM by having mechanisms in place through which the ISO can confirm the claimed capacity ratings of the VERs for the purpose of qualifying in the Forward Capacity Auction (“FCA”).¹¹

C. VER Integration Studies in New England

In 2009, the ISO completed a “Scenario Analysis of Renewable Resource Development” (the “Governors’ Economic Study”) – a comprehensive analysis for the integration of renewable resources over a long-term horizon, performed at the request of the Governors of the six New

⁹ Of these, approximately 555 MW are run-of-river hydro and 190 MW are wind plants, according to a draft of the 2010 Forecast Report of Capacity, Energy, Load and Transmission (“CELT”) Report for the 2010-2019 period, which was presented at the New England Power Pool Reliability Committee meeting on March 17, 2010, and is available at http://www.iso-ne.com/committees/comm_wkgrps/reliabty_comm/reliabty/mtrls/2010/mar172010/index.html. The ISO’s CELT reports provide the ISO’s annual 10-year forecast of capacity, energy, load and transmission. Another 4065 MW of proposed VERs presently are pending in the ISO’s interconnection queue. These include approximately 4055 MW of wind plants and 10 MW of run-of-river hydro. The ISO’s interconnection queue is available at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html.

¹⁰ See ISO Tariff, Section I.2 (defining “Intermittent Power Resources” to include those resources “whose output and availability are not subject to the control of the ISO or the plant operator because of the source of fuel (*e.g.*, wind, solar, run-of-river hydro),” among others).

¹¹ See *id.* at Section III.13.1.1.2.2.6.

England states.¹² The Governors’ Economic Study identified economic and environmental impacts for a set of scenario analyses that assumed the development of renewable resources in New England. The analysis also identified the potential benefits to the region from the significant sources of wind energy that are available in New England, the effective means to integrate them into the grid, and related preliminary transmission cost estimates. Certain scenarios considered in the analysis indicated that, through development in the Northeast, New England and its neighbors can effectively meet the renewable energy goals of the region. Other scenarios showed that the region can be a net exporter of renewable energy to contribute to national goals.

The Governors’ Economic Study ultimately informed the “New England Governors’ Renewable Energy Blueprint” (the “Blueprint”), adopted last year by the six New England state governors.¹³ The Blueprint sets forth policy objectives for the development of renewable resources in the Northeast that could ultimately lead to substantial penetration of VERs in New England.

Anticipating the penetration of large-scale wind generation resources in New England, the ISO also commissioned a comprehensive wind integration study in 2009 – known as the “New England Wind Integration Study” (the “NEWIS”)¹⁴ – to assess the effects of large-scale

¹² The Governors’ Economic Study is available on the ISO’s website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html. The Governors’ Economic Study was conducted pursuant to the Regional System Planning Process established in Attachment K of the ISO OATT, Section II of the ISO Tariff.

¹³ See Blueprint materials, available at <http://www.nescoe.com/Blueprint.html>.

¹⁴ See NEWIS materials, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/aug192009/a_newis.pdf.

wind penetration in New England using statistical and simulation analysis of historical data.¹⁵ Specifically, the NEWIS will determine the operational, planning, and market impacts of integrating substantial wind generation-resources for the New England Balancing Authority Area, with due consideration to the neighboring areas, as well as the measures that may be available to the ISO for mitigating any negative impacts while enabling the integration of wind generating resources. The NEWIS also will set forth recommendations for implementing these measures. In that regard, the NEWIS will identify the potential operating conditions created or exacerbated by the variability and unpredictability of wind generation resources, and recommend potential corrective activities, recognizing the unique characteristics of the tightly integrated bulk power system in New England and wind resources.

The NEWIS consists of five different tasks. While some of the tasks have been completed, the entire study will not be completed until September 2010. The first task – Wind Integration Study Survey – consisted of conducting a survey of national and international studies of integrating wind resources into the bulk electric power systems to determine the applicability of these studies to the ISO’s wind integration studies. This task has been completed. The second task – Technical Requirements for Interconnection – included the development of specific recommendations for technical requirements for wind generation resources.¹⁶ This task was completed in Fall 2009, with recommendations to the ISO detailed in a “Technical Requirements

¹⁵ See NEWIS Materials, New England Wind Integration Study (NEWIS) Wind Scenario and Transmission Overlays, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jan212010/newis.pdf.

¹⁶ Specifically, this task looked at elements such as wind generating resources’ ability to reliably withstand low-voltage conditions, provide voltage support to the system, and adjust megawatt output to support the operation of the system. This task included data and telemetry requirements, maintenance and scheduling requirements, high wind cutout behavior, and the development of best practice methods of the equivalent load-carrying (“ELCC”) calculation used for establishing capacity values for global and incremental wind power generation. This task also investigated and recommended wind power forecasting methods for both the very short-term timeframe, which is useful in real-time operations, and the short- to medium-term timeframe, which is useful in unit dispatch and day-ahead unit commitment.

for Wind Generation Interconnection and Integration” report (the “NEWIS Technical Report”).¹⁷

The third task – the Mesoscale Wind Forecasting and Wind Plant Models – has also been completed. This task consisted of the development of an accurate and flexible mesoscale hindcasting model for the New England and Maritime wind resource area (including offshore wind resources) that allows for the simulation of power system and wind generation operations and interactions (*e.g.*, unit commitment, scheduling, load following, and Regulation) over the timescales of interest. The model is designed to produce three years of realistic time-series of wind data in order to quantify the effects of inter-annual variability in wind generation and system-wide load. The last two tasks – Scenario Development and Analysis, and Scenario Simulation and Analysis – are currently underway. These tasks will statistically analyze the impacts of wind-development scenarios in New England on the performance of the electric power system,¹⁸ and simulate and analyze these scenarios to assess the measures needed to successfully integrate substantial wind generation,¹⁹ respectively.

¹⁷ See NEWIS Technical Report, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf. The ISO presented the recommendations of the NEWIS Technical Report to New England stakeholders at the November 18, 2009 meeting of the Planning Advisory Committee (“PAC”). It is important to note that the recommendations provided in the NEWIS Technical Report depend on work that has yet to be completed. These recommendations will be subject to the applicable stakeholder processes prior to implementation.

¹⁸ These scenarios are considering various levels of wind development up to 20% to 25 % of the projected annual consumption of electric energy. Sensitivity analyses include the impacts of varying levels of diversity of the wind portfolio on the performance of the electric power system. The evaluation also will include a review of the ISO’s market design considering a high penetration of wind generation and how the scenarios could affect system reliability and/or contribute to inefficient market operation of the bulk electric power system. Ultimately, this analysis will lead to recommendations for modifying existing procedures, guidelines, and standards to reliably and efficiently accommodate the integration of new wind generation.

¹⁹ This investigation is assessing the type of forecast needed, such as forecasting lead time, the required accuracy, and implementation issues. The simulations are evaluating the use of on-line generation for load following, Regulation, and reserve maintenance and deliverability; the production of air emissions; the effects of carbon cost; and the effects on LMPs. Measures that would facilitate the integration of wind generation resources, such as changes to market rules, the addition of electrical storage to the power system, and the use of demand response also are being studied.

The NEWIS work that has been completed to date has informed some of the ISO's responses to the questions posed by the Commission in the NOI. These responses may be further informed based on additional information that comes to light upon the completion of the NEWIS. The results of the complete NEWIS ultimately could spur changes to the ISO Tariff, Operating Procedures and Manuals. As stated earlier, the ISO has presented the work completed to date to stakeholders, and will continue to work with stakeholders to discuss the study's findings, and then complete a full stakeholder process within New England prior to filing with the Commission any rule changes developed to enable the integration of VERs.

V. COMMENTS AND SPECIFIC RESPONSES

A. Data and Forecasting

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?

Currently, in New England, the Lead Market Participant for each VER performs its own forecast of generation for each hour of the next Operating Day and submits this information to the ISO as a self-schedule (forecast) on the day preceding the Operating Day. If, during the Operating Day, the actual hourly generation is expected to deviate by a significant amount from the self-schedule of the plant, the Lead Market Participant revises the generation schedule for each hour of the forecast that it is forecasted to deviate during the Operating Day. The revision to the schedule is usually based on the latest forecast or current output and is submitted for the rest of the Operating Day. This practice allows Lead Market Participants for VERs to utilize a more accurate self-schedule during the Operating Day based on actual conditions or more recent forecasts (*e.g.*, wind or hydrological flows). Using the latest generation forecast for the rest of the Operating Day may reduce the VER's need to revise its generation schedule at a later time.

While the ISO's current practice in forecasting load and the corresponding generation

requirements works well today, it is not a viable practice to have in place with a large penetration of VERs into the New England Transmission System. This is due primarily to the potential volume of VER and quantity of revisions required as a result of the nature of the VER and/or its forecast, which may not be aligned with the Balancing Authority Area's metrics and requirements for operation of the larger system. Moreover, under the current practice, because the Lead Market Participants for VERs only revise schedules when the expected generation is outside of the previous forecast, with no requirement to update forecasts at certain intervals in real-time, the ISO does not necessarily have the most accurate expected VER generation data for use in its Reserve Adequacy Assessment ("RAA") (*i.e.*, reliability commitment), which the ISO conducts approximately every three hours. Provision to the ISO of the latest VER forecast data for use in the reserve adequacy process will better ensure system adequacy when the amount of energy in the system produced by VERs substantially increases.

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?

The ISO understands a "state-of-the-art forecasting system" to mean a generation forecasting system that in the operational timeframe helps to make the most efficient use of the energy produced by VERs and non-VERs while helping to ensure system reliability and market efficiency. A state-of-the-art generation forecasting system works toward these goals by producing a forecast for expected VER generation for, ideally, a range of time frames, including next hours, next day, and the following week in order to allow for optimization of short-term maintenance scheduling, and an optimized unit commitment and real-time unit dispatch..

Different techniques will be required in order to generate such a forecast and it is recognized that, though perfect foreknowledge of a next-week forecast for VER generation would be ideal, significant benefits also can be gained from even imperfect forecasts. The generation forecasting for VERs generally will be more accurate the closer these forecasts are to real-time, recognizing that the effort required to increase the accuracy of an imperfect forecast is likely to increase (with some limit) closer to real-time. For example, a “ballpark” VER generation forecast probably will be sufficient for one week ahead; closer to the Operating Day, the need to recognize more fully inter-temporal constraints (*e.g.*, minimum run time) of non-VER generation will increase the value of a more precise VER generation forecast, and a more precise VER generation forecast will reduce reserve margins required to meet unexpected changes in VER generation. Moreover, accurate very short-term forecasting (*i.e.*, next hour-ahead to next ten-minutes-ahead) will allow more changes in VER generation to be accommodated in the RTM through economic dispatch as opposed to being met by carrying higher levels of more costly Regulation and spinning reserves in all hours.

The first step in a transition from the existing forecasting method to a state-of-the-art forecasting system is to determine and describe the pertinent goals, methods, and requirements. The second step is to develop, test and implement a plan for the transition from the existing system to the new system. The NEWIS Technical Report, described in Section IV, addresses this first step by identifying the recommended goals, methods, and requirements for a state-of-the-art wind generation forecasting system.

Specifically, the NEWIS Technical Report provides specific recommendations as to the type of data that should be required and the frequency with which that data should be provided.²⁰

²⁰ See NEWIS Technical Report at 16-17.

According to the NEWIS Technical Report, to provide the most accurate power production forecast, it is essential that both power production and meteorological data be made available.²¹ As the report recommends, static-type data should include the following specifications: nameplate capacity, turbine model, number of turbines, turbine hub height, coordinates and elevation of individual turbines and meteorological structures (*i.e.*, towers or masts or other means of gathering free-stream ambient meteorological data).²² Operating conditions to be made available include: wind plant status and future availability factor, number or percentages of turbines on line, plant curtailment status, average plant power or total energy produced for specific time intervals, and average plant wind speed and average wind direction.²³ The report recommends that the “total aggregate plant power production data and plant availability should be sent to forecast providers for each forecast interval.”²⁴

The NEWIS Technical Report recommends the provision of meteorological condition data (such as wind speed and direction) that represents free-stream ambient conditions (*i.e.*, not affected by wind turbine wakes, for example). One potential method to measure and report such data would be to use an on-site meteorological structure. Other meteorological condition data to be provided should include: air temperature, air pressure, air humidity or other atmospheric moisture parameter.²⁵ In addition to meteorological structure data, the NEWIS Technical Report also recommends the following meteorological data from a representative selection of wind

²¹ *Id.* at 16.

²² *Id.* at 17.

²³ *Id.*

²⁴ *See id.*

²⁵ NEWIS Technical Report at 18.

turbines: wind speed and direction data from nacelle-mounted instruments.²⁶ The report also makes recommendations with regard to the location and spacing criteria for the turbines providing this data, but notes that giving “exact spacing criteria” is a challenge since “these depend on factors such as local weather regimes, terrain complexity, and available of nacelle data.”²⁷

An implementation plan detailing the exact manner in which the ISO will transition from the existing system to a state-of-the-art wind generation forecasting system has not yet been developed since some of the recommendations depend on work that has yet to be accomplished and integrated into the NEWIS Technical Report’s findings. The NEWIS Technical Report has focused on wind generation resources as the most significant category VERs for the New England grid, but the ISO will also be examining requirements for the integration of other VERs. The ISO has yet to study generation forecasting for solar resources, but presumably for VERs that depend on insolation as a “fuel” source, relevant ambient condition data for generation forecasting include present and expected cloud cover, projected incident solar irradiance (or perhaps theoretical maximum plant output) given no cloud cover, temperature, and relative humidity. The data reporting frequency for solar resources would likely be similar to that required for wind generation resources.

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?

This response assumes that the “non-VER System Operator” refers to a System Operator of the Balancing Authority Area that may or may not contain VERs. Given this assumption, the

²⁶ *Id.*

²⁷ *Id.*

data that a non-VER System Operator needs may include the same data specified in the prior response, along with other power production/plant-status data.²⁸

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?

This is an area of concern for System Operators since the majority of VER generation forecast products that are currently available are not focused on ramping events, which can result from “a change in power output that has a high enough amplitude over a short enough period of time to cause short-term grid management issues.”²⁹ Unanticipated ramping can cause operational issues such as shortages of reserves if a ramp down of wind is coupled with an increase in load or a ramp up in wind is coupled with a decrease in load, leading to operating reserve deficiencies or minimum generation events, respectively. Effective forecasting is needed to minimize these issues.

The NEWIS Technical Report recommends a ramping forecasting system that can alert operators about the occurrences of a ramp as early as possible. Specifically, the NEWIS Technical Report recommends the following alert system:

For days 3 through 7, only daily probabilities should be given in terms of the likelihood of a ramp being greater than, about the same as, or less than the seasonal norm for such an event. The day-ahead forecast should be more precise giving probabilities of ramp occurrence for each hourly time period. The forecasts needed for the first 24 hours should include the probability, amplitude (magnitude), duration, type, and cause of the event. The 24-hour forecast should also include the meteorological feature causing the ramp in order to aid operators in tracking the event in real time. Finally, the alert system should include hourly

²⁸ See NEWIS Technical Report at 12-13 (listing signals that should be sampled at the normal SCADA uprate rate signals and status signals at a lower rate that should be provided by wind plants, but may also be applicable to other VERs).

²⁹ *Id.* at 83. See also *id.* at 84.

ramp forecast updates for situations when a ramp event has been forecasted within 24 hours.³⁰

The NEWIS Technical Report further recommends that the early ramp forecasting system be considered a separate system – with a separate methodology and a separate design. As explained in the Report:

The ramp forecasting system needs to be different from the forecasting system designed to reduce typical errors by minimizing the [Root Mean Square Error or (“RMSE”)] or other standard metrics. Inevitable phase errors in features causing ramps (such as cold fronts) can produce large errors especially when considering squared [measure of error] quantities such as RMSE. For this reason, a forecast system that minimizes RMSE tends to smooth out power ramps over many hours. Ramp forecasting systems should be designed to estimate the probability of a ramp occurring in any given hour, the actual amplitude (or a probability distribution of amplitudes), and the uncertainty in timing/duration of the ramp. Inputs to such a system would include amplitude and timing of actual ramps forecasted by physics-based (numerical weather prediction or *NWP*) models, a statistical forecast method, or an optimized ensemble forecast.³¹

To forecast ramps, the NEWIS Technical Report recommends the development of “ramp climatologies for the region.” Ramp climatologies, as the report explains, can be used by the forecast provider to develop “algorithms to identify regional or local parameters from available met tower or remote sensing system data that have a statistically significant ability to discriminate between ramp and no-ramp cases, especially during the first hours of a forecast.”³² This information then can be analyzed “to identify the sensitivity of site specific ramp forecasts to making additional measurements at different locations.”³³

The best validation for forecasting is demonstrated performance for regions with similar VER characteristics; however, it would be difficult to acquire this performance data given the

³⁰ *Id.* at 84.

³¹ NEWIS Technical Report at 84.

³² *Id.* at 84-85.

³³ *Id.*

general lack of experience with many types of VERs. In lieu of demonstrated performance, performance-tracking combined with some public release of forecasting inputs and data (which facilitates a robust forecasting community) and performance incentives for the forecaster will be most effective in producing VER generation forecasting with high accuracy and utility.

State-of-the-art forecasts may necessitate the sharing of meteorological data across regions to assure that the movement of weather patterns can be accurately predicted and analyzed. To what extent should meteorological data be made publically available to aid in the development of state-of-the-art forecasts? Should the Commission require public utilities to maintain a meteorological data reporting system? If so, should such a system be akin to or in collaboration with Open Access Same Time Information System (OASIS) postings? In order to retain the confidentiality of commercially sensitive data reported by VERs for the purpose of developing state-of-the-art forecasts, what limits and/or safeguards should be established to protect operational data and generator outage reports?

Sharing of operational data would be helpful for the development of large-scale VER forecasts at three different levels: national/multi-region forecasts, regional forecasts, and individual VER operator forecasts.

Neighboring systems would use their combined data to develop a national/multi-region forecast. A multi-region forecast would require some data input from VER operators and aggregated inputs from regional System Operators. Outputs from a multi-region forecast could be very similar to the outputs produced today by the National Weather Service (“NWS”) forecast, albeit perhaps at a different level of granularity both in time and in space. Each regional System Operator would use the outputs from the multi-region forecast (as well as other more localized data such as operational data from the VER operators in its region) to obtain a more refined VER generation forecast for the VER generation in its region. Currently, NWS forecasting often forms the basis for the initial and boundary conditions for regional VER generation forecasting. The NWS forecast, however, has not been optimized for accuracy in power production from weather-sensitive generation. The individual VER operators also would

use data to create its own forecast based on multi-regional forecasts, NWS meteorological forecasts, and other highly localized data (*e.g.*, exact landcover in the region of a windplant).

Such a three-tiered approach would allow for neighboring systems, System Operators and individual VER operators to develop forecasts for their specific needs and to carry out their respective responsibilities. A VER operator would be able to create a forecast that can help it maximize the operation of its resource. A System Operator, as the entity concerned with the aggregate forecast, would create a centralized forecast to operate efficient markets while maintaining reliability. Broad information sharing among neighboring systems would facilitate interregional planning and market operation. Additionally, a three-tiered approach would allow for varying levels of redundancy in the event of failures and/or errors in different parts of the system. VER operational data should be shared in the same manner as other market-sensitive data is shared today – by use of a secure mechanism that ensures confidentiality of the data.

It should be noted, however, that for the purpose of a security constrained unit commitment, the forecast used by the Balancing Authority Area to produce the current operating plan and updates to that plan, should be heavily weighted to the centralized weather forecast produced by the Balancing Authority Area based upon Balancing Authority Area reliability metrics, while using the VER projections as an additional input to that forecast.

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?

A decentralized forecast is a useful input to the centralized forecast developed by a System Operator, which is the entity concerned with the aggregate forecast for the power system and how that power system as a whole will behave, and decentralized forecasts would appear to be useful for VER operators who are trying to maximize the operation of their resources.

However, it is essential that the *centralized forecasting* method be utilized as the primary driver for the reliability commitment within each Balancing Authority Area in order to ensure reliability. The decentralized forecast provided by VER operators should be used as an input to the creation of the reliability commitment, but the balancing and transmission entities should be responsible for the final product used in operations.

To what extent is a lack of data regarding the operational status and forecasted output of distributed, or behind-the-meter, VERs leading to a need for additional reserves? To what extent would the provision of such data reduce the need for System Operators to rely on reserves?

Due to the low penetration levels, there currently is no significant need for the ISO to know the operational status and/or forecasted output of distributed/behind-the-meter VERs. This data, however, will become more important as the number of distributed VERs, and therefore the amount of energy produced, increases.

At this time, it is difficult to determine where the tipping point would be between essentially no (or very small) operational effects and operational effects that are large enough to be of concern. One possible metric that could be used to determine this tipping point could be the relative amounts of variability: if the variability of distributed VER generation over a particular timeframe of interest approximates the magnitude of the variability of the system load, further study will be warranted. A practice employed in areas with large amounts of VER that is not “visible” to or controllable by the System Operator (*e.g.*, in Germany) is to develop a generation forecast based on extrapolation of a representative subset of VERs that is visible to the System Operator.

Because enhanced knowledge of the resources on the system ultimately leads to more efficient operation, at a minimum, all distributed generation regardless of size should be required to formally provide to the balancing and transmission entities in its area the technical

specification of the technology and precise location of the installed resource so that a forecast of output can be developed on an aggregate scale to include in the balancing area forecast. This practice should be encouraged now to avoid any need for grandfathering of existing and future resources, since distributed VERs can proliferate quickly.

B. Scheduling Flexibility and Scheduling Incentives

Scheduling Flexibility

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?

For areas with bilateral markets where internal generation and external interfaces are scheduled and modified on an hourly basis, any reduction to that interval will allow System Operators to more efficiently manage the ramps of VERs and demand. It is interesting to note that many countries outside North America have a standard scheduling interval of thirty minutes, where there are 48 trading and settlement intervals in a day. However, because the New England market design uses a security-constrained economic dispatch that dispatches internal resources on five-minute intervals, the ISO's response focuses solely on rules and practices related to inter-area ties (*i.e.*, external transactions between the areas over external interfaces).

As described in Section IV, the ISO currently utilizes an hourly interval for scheduling on inter-area ties. Shorter scheduling intervals would not allow the System Operators to more efficiently schedule internal resources to manage ramps of VERs and/or demand or reduce the overall reliance on reserves and regulation *unless and until* the variation of the VER output results in a corresponding change in the scheduled flow on the external interface. For example, if market rules allowed for the change in flow on the interface to occur in a manner at odds with a change in VER output (*i.e.*, an increase or decrease), such a process could have a detrimental

impact on reliability.

More frequent scheduling intervals could potentially provide increased flexibility to the System Operator. That benefit, however, can only be maximized when the scheduled flow on the external interface allows for both future increases or decreases in flow. At times when, whether for economic or other reasons, the scheduled flow in one direction is already at the external interface limit with no provision for decreasing flow, the flexibility associated with a more frequent scheduling interval cannot be realized. While more frequent scheduling intervals on the external interface have the potential to increase flexibility for the System Operator, access to that flexibility is dependent on system conditions and cannot, alone, solve the issues associated with managing VER output within a system.

Neighboring control areas could influence the change in flow through various means, including market actions and/or actions by the System Operator. Currently, the ISO is actively considering improvements to scheduling rules and practices on its external interfaces to enhance market efficiencies. In particular, the ISO has been considering how changes to the external transaction rules and operational processes could help manage the projected increase in VER penetration and the complexities of implementing those changes. The complexities of implementing shorter scheduling intervals between New England and its neighboring areas, for instance, depend on the nature of the markets on either side of the border.³⁴ Further development

³⁴ Market-to-market physical external interfaces are fairly predictable because participants using the external interface must arrange for transmission service on one side of the border to submit transactions. Market-to-market interfaces are more complex, particularly because participants are able to submit transactions and update them as needed during the day in response to market practices. Implementation of shorter schedule intervals over the market-to-market external interface between New York and New England, for instance, presents unique challenges. These challenges stem from the manner in which external transactions are currently submitted and selected. Briefly, the New England Market Rules permits the submittal of self-scheduled external transactions. In fact, the majority of transactions scheduled on the New York-New England interface are self-scheduled in New England. In New York, however, all market transactions must be priced. Accordingly, the clearing of NYISO's hourly market determines which transactions will be scheduled between New York and New England and, until that market has cleared, the
(continued...)

and consideration of future changes regarding external interface scheduling rules and practices will require coordination with New England’s neighboring systems and New England’s stakeholders.

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?

Would intra-hour scheduling at interties present problems for RTO/ISO markets? If so, describe the problems and feasible solutions for intra-hour scheduling at interties.

The ISO’s response to these questions considers New England’s current state, in which VERs have minimal impact on the system, and New England’s future state, in which VERs are projected to have an impact due to substantial penetration.³⁵ For ease of review, this progression is described in Cases A through C, below. As transition from the current to the future state will not occur unexpectedly, changes to inter-area processes that can help mitigate that impact can be fully vetted as part of that transition.

Case A: Neither the ISO nor neighboring areas have substantial VER penetration

VERs do not currently have a noticeable impact on the New England and neighboring markets beyond local transmission congestion, which cannot be addressed by increased scheduling frequency. Implementation of shorter scheduling intervals would require an

(...continued)

net interchange is unknown to the ISO. This makes it difficult to implement scheduling more than once an hour. Moreover, as the ISO does not intervene in self-scheduled transactions, any self-scheduled transactions that clear in NYISO’s hourly market will flow in the next hour. Increasing participants’ flexibility to submit transactions with shorter intervals (and therefore, with shorter notice) could result in continuous overreaction to market conditions. As noted earlier, the ISO and NYISO are currently working together to improve the efficiency of scheduling on the New York-New England interface to consider the price impact on both sides of the border. *See* 2010 Wholesale Markets Project Plan, ISO New England, available at http://www.iso-ne.com/pubs/whlsle_mkt_pln/index.html (noting the ISO’s efforts to work with NYISO to “improve the economic utilization of the transmission ties and leverage the regions’ capabilities”).

³⁵ The ISO’s response also focuses solely on rules and practices related to inter-area ties (*i.e.*, external transactions between the areas over external interfaces), as the New England market design uses a security-constrained economic dispatch that dispatches internal resources on five-minute intervals. *See* Section IV, *supra*.

assessment of the current market rules and participant scheduling practices. Currently, all transactions that are “self-scheduled” on an external interface appear to be economic, and scheduling those transactions more frequently will not change the megawatt amount of a transaction selected or the specific transactions selected. Accordingly, changes to market rules would be necessary to require, or create incentives for, changes in current scheduling practices in order to implement more frequent scheduling. However, given the absence of substantial VER penetration, the ISO would need to investigate whether such a change would result in any gain in functionality.

Case B: Neighboring area(s) has substantial VER penetration, but the ISO does not.

In the case where a neighboring area expects substantial VER penetration, and frequent scheduling on the external interface between New England and the neighboring area will help the neighboring area accommodate VERs within its system, the ISO would need to consider changes to existing rules and operational practices. The ISO would consider undertaking changes to existing rules and operational practices, including supporting different scheduling rules on different interfaces, to respond to unique conditions between New England and each neighboring area, in a manner that does not produce less efficient results in the New England Markets. One approach to accommodate this would be to require transaction submittals to the ISO on an hourly basis, as required under the existing Market Rules, but provide for the interface to be scheduled on a shorter interval. If a neighboring area allows its participants to modify transactions more frequently, presumably to follow the varying output of VERs, this approach would allow the ISO to coordinate those scheduling changes more frequently than once an hour. The ISO’s control room tools would need to be enhanced, however, to accommodate this type of scheduling practice.

Implementation of this type of scheduling would require an assessment of potential impacts on the New England Markets. If a neighboring control area, for example, allows the submittal of transaction changes that are dependent on the VER output and the transaction is self-scheduled in the New England Markets (which is typically the case), this process could result in inefficient dispatch of the systems. Because nearly all external transactions are self-scheduled into the ISO, the ISO would be in a position, as a technical matter, to accept any changes requested by the neighboring area in response to the neighboring area's VER output, but doing so would not account for economic impacts on New England. If, for example, in response to a shift to more frequent scheduling, existing rules were modified to require all external interface transactions to submit economic offers (*i.e.*, removing the option to self-schedule), pricing correlation between New England and its neighboring area would increase, as would the flexibility of transaction flow. The ISO would need to consider these types of market impacts in order to realize the benefits, and avoid unintended consequences, of accommodating shorter interval schedules.

Case C: The ISO and one or more neighboring areas have substantial VER penetration

This case would require consideration of modifications to market rules and operational practices to determine the most cost effective means of addressing substantial VER penetration in the ISO and the neighboring areas, if more frequent scheduling is found to benefit the markets. Processes and parameters that could require modification in order to improve the efficient use of the external interface would include, at a minimum: the transaction submittal and selection processes, ramping constraints, and the settlements systems.

Increased coordination and joint transaction submittal and selection processes will need to be in place in order to ensure reliability if scheduling frequency increases. Currently, many

transactions are submitted every hour on the ISO's market-to-market interfaces and, under the submittal process in place today, it is unclear until the neighboring market has cleared which transactions will pass the "check-out" process and flow in real-time. The ISO and its neighboring systems will need to enhance the market rules and corresponding submittal processes so that each transaction can be assumed to pass the "check-out" process. Rules also would need to be developed to determine how many megawatts of hourly transactions should be selected at the top of the hour and which transactions will be adjusted on a shorter interval. Scheduling rules to determine the mix of hourly and shorter transactions also would be necessary to address ramping constraints. Consider the issues presented by the following example: If the existing rules allow for ramping of 500 MW/hour of interchange ramping and it is known that ramping of 200 MW every 15 minutes could be accommodated (*i.e.*, 800 over the hour), but that ramping of 500 MW at the top of the hour and an additional 200 MW at 15-minute intervals thereafter could not be accommodated, (a) what ramping should be allowed at the top of the hour, and (b) should the scheduling at the top of the hour favor the hourly transactions, since the shorter transaction can be modified later in the hour?

New England currently has an hourly integrated settlement system in place. That is, the settlement of the New England Markets occurs based on the integrated hourly megawatt and locational marginal price values. Implementation of shorter scheduling intervals thus would expose shorter transactions to prices that were not occurring during the time the transaction was scheduled, unless there is a corresponding change to shorter settlement intervals. Intra-hour scheduling would also have an impact on the settlement of Net Commitment Period

Compensation (“NCPC”)³⁶ credits/charges. These impacts would need to be considered, and the benefits of any proposed changes to address these impacts would need to be weighed against the overall costs stemming, *inter alia*, from the substantial settlement software changes that would be required.

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?

Ultimately, the optimum scheduling interval would be to dispatch external transactions simultaneously with internal generation, which is done at a five-minute interval or upon demand in New England. To realize a five-minute dispatch on any market-to-market interface, the five-minute dispatch would need to produce the same resulting set of transactions on both sides of the interface in order for the schedule to flow as dispatched. While the ideal scheduling interval time increments would be on a five-minute or an on-demand basis, if price signals can be achieved and considered on both sides of an external interface, any increase in scheduling frequency above the current hourly process would improve the efficient use of the interface with respect to the generation located within each area. Conversely, increasing the frequency of interface scheduling without considering the impact on the price in each area might not have any increased benefits to the marketplace.

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?

At this time, the impacts that implementing additional scheduling flexibility could have on the NERC INT standards and whether such flexibility could affect other processes and reliability standards are unknown.

³⁶ NCPC is the settlement of credits to suppliers that did not receive full compensation in the energy market and the corresponding charges to offset those credits. *See* ISO Tariff, Section I.1.2; *id.* at Section III.C.

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?

Changing to intra-hour scheduling would affect many tools directly used by and supporting the System Operators. In March 2009, the ISO conducted an intra-hour (30-minute) scheduling pilot with the New Brunswick System Operator (“NBSO”) on the NBSO interface. This pilot proved very useful in identifying the obstacles to proceeding with permanent changes to the scheduling timeframe. Some of those items are reflected in the “Case C” discussion above. In particular, issues relating to “wheel through” transactions were identified, in that all areas on the transmission path need to be utilizing the same scheduling periodicity. Many areas have moved to electronic dispatch of generation resources to decrease response time; this move required new tools. Similarly, new tools would be required to support more-frequent-than-hourly electronic transaction scheduling. The ISO has not quantified the costs of implementing any permanent change. In addition, if intra-hour scheduling requires changes outside the control room (for example, in the settlements regime), the costs associated with the changes would be substantial, and would impact many entities throughout the industry.

In 2004, the ISO and NYISO jointly investigated the use of a market-related version of real-time “pool-to-pool” economic energy dispatch, which was referred to as “virtual regional dispatch” or VRD, and conducted a pilot program in 2005. There were, however, significant implementation obstacles and disagreement from ISO stakeholders on this proposed effort. The use of real-time “pool-to-pool economy energy” dispatch involves System Operators closing the price arbitrage between regions through joint scheduling of intra-hour transfers. This advantage of this design is that it allows System Operator to make immediate decisions based on real-time prices and reliability information available to them without the delays associated with Market Participants submitting transactions or continuously over-responding to market signals. This concept could be revisited in the context of higher VER penetration.

Scheduling Incentives

Has the exemption from third-tier penalty imbalances worked as a targeted exemption that recognizes operational limitations of VERs, or has it encouraged inefficient scheduling behaviors to develop? If the latter, what reforms to this exemption would encourage more accurate scheduling practices?

The imbalance provisions of the *pro forma* open access transmission tariff are not applicable in New England. As described in Section IV, generator-related energy charges in New England are governed by the multi-settlement, locational-based energy market pursuant to the Market Rules.

Assuming that efficient forecasting and scheduling practices help minimize deviations between scheduled and actual energy output of VERs, are additional incentives needed to encourage VERs to submit schedules that are informed by state-of-the-art forecasting? What would be the proper incentives?

As VER penetration levels increase and operational impacts are predicted, the availability of accurate forecasts becomes imperative. While these forecasts can be supplied by the VER owners/operators initially, the development of a *centralized forecasting regime* that accounts for

metrics³⁷ that are important to Reliability Authorities, Balancing Authority Areas or Transmission Owners becomes essential with the increasing penetration of VERs and the concomitant potential for operational and/or market inefficiencies. It is essential that the centralized forecast meet performance criteria that correlate with the metrics that the reliability entities are required to utilize. Accurate forecasting can be fostered by a combination of requiring forecast submission to System Operators and providing incentives for owners/operators of VERs to provide accurate data (of the types detailed in Section V.A, above) for their resources via a secured and confidential communications infrastructure to be used by a centralized forecaster to develop an accurate forecast.

Under an RTO/ISO market design, are there sufficient incentives to encourage VERs to submit accurate schedules? What costs and/or penalties should be assigned to VERs when their real-time output is not accurately scheduled on a forward basis? Should VERs be treated the same as conventional resources with respect to deviations from their production schedules?

As discussed in Section IV, the current ISO Market Rules, in effect, insulate VERs from the need to forecast accurately. These resources are not required to offer into the DAM, and are not subject to Real-Time NCPC Charges, whether or not they participate in the DAM.³⁸ This treatment is not a problem due to the paucity of online VERs, but requires re-examination by the ISO. The ISO plans to undertake an analysis of the possible benefits of changes to the Market Rules that would expose VERs to both the price risk of DAM and RTM energy deviations plus a share of the cost of managing uncertainty, as captured in Real-Time NCPC Charges. Such

³⁷ Such metrics need to include the ability to avoid and mitigate System Operating Limit and Interconnection Reliability Operating Limit violations, and the ability to maintain operating reserves in accordance with the NERC Disturbance Control Standard and Control Performance Criteria; such as, Control Performance Standard 1 and Control Performance Standard 2.

³⁸ The current Market Rules provide for the allocation of Real-Time Economic NCPC based on day-ahead and real-time deviations for both generation and load, as a measure of the responsibility for cost causation (if real-time conditions precisely matched day-ahead schedules, there would be no uneconomic commitments).

changes would involve eliminating the current VER exemptions from: (1) the requirement that all capacity resources offer into the DAM, and (2) Real-Time NCPC Charges. Exposing VERs to these costs in the same manner as other capacity resources could give VERs a direct incentive to cost-effectively reduce their production uncertainty through investments in better forecasting, financial hedges, energy storage, and the like.

C. Day-Ahead Market Participation and Reliability Commitments

Day-ahead Market Participation

In this section of the NOI, the Commission asks several questions with respect to the value of VER participation in the day-ahead market.³⁹ The ISO offers the following general comments in response to those questions.

Currently, as described in Section IV, the New England Market Rules do not require VERs to offer into the DAM, and these resources are not subject to Real-Time NCPC Charges, whether or not they choose to participate in the DAM. This treatment is not a problem today, but will be examined by the ISO in the context of large-scale penetration of VERs, as noted in Section V.B. Specifically, the ISO plans to analyze whether VERs should be required to participate in the Day-Ahead Energy Market, particularly those VERs with obligations in the Forward Capacity Market. While a closer examination of the potential benefits that the use of the DAM may result in is worthwhile, the implementation of a robust centralized forecasting methodology at the ISO can address most operational risks (except for those stemming from inevitable weather forecasting errors). A robust centralized forecast over several time scales (*i.e.*, next day, next several hours, within hour) and frequent, continuous, and accurate reporting of VER status also will help dispatch software and System Operators' proactive response to

³⁹ See NOI at P 28.

changing circumstances in a manner that minimizes or avoids costly out-of-market actions.

Reliability Commitments

Would the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour reduce the amount of reserves needed and/or reduce system uplift costs? What would be the optimal time (e.g., 4 to 6 hours ahead of the operating hour) for such a process?

In New England, the current reliability assessment and commitment process is completed on a continuous basis as needed. More specifically, the process is updated at least once every three hours or on demand as a matter of process throughout the Operating Day. This practice has been in place since 2003. Because the ISO is able to update the plan on demand, based upon certain thresholds in changes to transmission and/or resource availability, there has not been a need to implement shorter time intervals.

Would an additional market that coincides with the timing of an intra-day reliability commitment process be beneficial in the forward scheduling of VERs? If such a market is implemented, would an intra-day reliability commitment process be necessary? Should the frequency of scheduling intervals resulting from such a market coincide with intra-hour schedules discussed above?

As described in Sections IV and V.A, multiple in-day reliability commitment processes are already available in New England. Turning these processes into a market structure may be unnecessary and the costs associated with creating such a market would more than likely outweigh its benefits.

What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?

Centralized forecasting should be the cornerstone of the reliability and assessment commitment once the forecast has been determined to be operating within the expectations established for the area. The centralized forecasting metrics should include confidence intervals for the various time scales under consideration, and metrics such as Root Mean Square Error ("RMSE") and Mean Absolute Error ("MAE"), as well as separate ramping forecasts to show

phasing and magnitude of VER ramps that might be expected on a day-ahead, hour-ahead, and/or several-minutes-ahead basis. In addition to the above, severe weather forecasting and its implications for VER output should be considered a vital part of any centralized forecasting regime put in place at the Reliability Authority, Balancing Authority or Transmission Operator level.⁴⁰

D. Balancing Authority Coordination

In this section, the Commission poses a series of questions relating to the creation of larger Balancing Authority Areas to enable the integration of VERs.⁴¹ The ISO offers the following general comments in response to these questions. The ISO's references to a larger Balancing Authority Area in these comments mean larger balancing authority areas for all resources and not a VER-only balancing authority area.

1. Benefits of Larger Balancing Authority Areas

As a general matter, having Balancing Authority Areas encompassing a larger geographic footprint can be beneficial to some types of VERs. Larger geographic areas may have a more diverse mix of resources to balance VERs. In New England, for example, a number of different generation technologies are utilized, including flexible combined-cycle gas facilities. The benefits that a large geographical Balancing Authority Area could provide, however, can only be realized if transmission facilities are capable of moving power throughout the system so that, for example, as resources reduce output, power from other resources can still reach the load being served. Balancing Authority Areas, like that comprising the six-state New England region, are

⁴⁰ See NEWIS Technical Report at 15.

⁴¹ See NOI at P 33.

geographically large enough to integrate large amounts of VER that benefit from geographic diversity and the diverse resource mix within the region.

The potential for large-scale VER integration in the New England region is shown in the New England Governors' Economic Study, described briefly in Section IV. As that study shows, the limiting factor in the region is not the geographic size of the New England area, but the transmission infrastructure needed to move large amounts of power around the system.

2. Elements for Establishing Larger Balancing Authority Areas

Issues related to Balancing Authority coordination, consolidation and operation with VERs do not lend themselves to a “one-size-fits-all” approach. In this section, the ISO identifies several elements that should be considered as regions evaluate the tools and processes that are necessary to remove barriers to integrating VER or, for that matter, any other technology. These tools and processes should be evaluated prior to, or in conjunction with, any consideration of Balancing Authority coordination and consolidation not just for VER integration, but as part of an ongoing assessment of all technologies impacting the electric system.

First, it is essential for a Balancing Authority Area footprint to have robust, fast-acting markets or market-like processes to meet the needs of the power system and enable the integration of VERs. Such markets or processes should include:

- Day-ahead and real-time energy markets that reflect the cost of the next megawatt to ensure load and reserve requirements are met. The real-time energy market should be able to allocate resources to meet the system needs at very short intervals, ideally, at five-minutes or on demand. Operating within these short real-time intervals allows for maximum response to price signals which can enable the VERs by managing their variability. These energy markets should include the ability to provide electronic signals to all resources in order to effectively respond to the price signals of the market.
- A regulation (Automatic Generation Control) market that can help with managing the short-term variability of VERs in order to maintain frequency and scheduled interchange within

performance criteria.⁴²

- Forward and real-time reserve markets which reflect scarcity reserves through pricing mechanisms that encourage investment in fast-start technologies; fast-start technologies can aid in the integration of VERs by compensating for the variable and sometimes difficult-to-predict performance of VERs.
- A capacity market that enables the development of conventional generating resources, but also provides for the development of new technologies, such as VERs. The capacity market should allow for non-traditional technologies, like energy efficiency programs and demand response programs, which can be used to respond to extreme VER ramping events or move on-peak demand to off-peak periods when wind generation resources may be able to provide higher energy deliveries to the system.

Balancing Authority Areas should also enable the development of new technologies and expansion of existing technologies that can increase flexibility and interoperability to the system, such as battery storage, pumped storage, flywheel technologies, plug-in electric vehicle integration and smart grid solutions. They should also develop effective forecasting mechanisms and data collection processes for VERs, in order to effectively integrate their dispatch into security-constrained unit commitment processes that are constantly updated through the operating day.

Second, the Balancing Authority Area should assess the impact of increased VER penetration within its area and the neighboring areas to determine what operational, planning and/or market changes would be needed to enable VER integration within the balancing area. In particular, the studies should identify the potential adverse operating conditions created or exacerbated by the variability and unpredictability of VERs and recommend potential corrective actions, accounting for the unique characteristics of the electric system in question, among other elements. As actual VER penetration ensues, the conclusions of such studies should be

⁴² In New England, the combination of electronic dispatch signals and Automatic Generation Control capability has resulted in high Control Performance Standard 1 and Control Performance Standard 2 performance with a minimum of requirements and surplus capability that could be used to provide for a higher penetration of VERs.

reevaluated to monitor actual performance versus expected performance to determine whether the conclusions reached have proved to be correct or whether further analysis is warranted.

Third, the Balancing Authority Area must provide for a regional system planning process that ensures the development of a reliable and efficient transmission system to meet current and future power needs. This process must provide for coordination at the local, regional and interconnection-wide level, with coordinated development of infrastructure that begins at the local level, and builds to the national and international levels. While these efforts should focus on meeting the reliability needs of the system, they also should consider the appropriate metrics and criteria in evaluating economic justification and cost allocation methodologies that will aid in meeting reliability, economic and public policy objectives. Answering the transmission development and cost allocation questions of who pays the costs of additional transmission needed to efficiently move energy produced by VERs around the system so that the benefits of large footprints are realized will lead to a more effective integration of VERs well before the need to consider consolidation of balancing authority areas consolidation.

Finally, each Balancing Authority Area must work with neighboring areas to reduce seams that create obstacles to cross-border interchanges of electricity (*e.g.*, due to inflexible scheduling protocols) and/or sharing of resources across boundaries. Activities to reduce seams already are under consideration between many Balancing Authority Areas, including New England. Neighboring Balancing Authority Areas should consider activities such as: (a) reducing notice and scheduling intervals such that external transactions can respond in a manner similar to resources operating within a well-functioning and quick-responding energy and

ancillary service markets;⁴³ (b) expansion of reserve-sharing agreements that allow a Balancing Area Authority to respond to events external to its system as if the event occurred within its boundaries; (c) extension of the ACE Diversity Interchange,⁴⁴ which could have a direct effect on the integration of VER by allowing multiple balancing areas to respond to short-term changes in an expedited and shared manner; (d) potentially allowing scheduling of external transactions in accordance with a price threshold instead of self-scheduling; and (e) elimination of cross-border tariffs or delivery expenses to remove the so-called “hurdle rates” to movement of power between balancing areas.⁴⁵

E. Reserve Products and Ancillary Services

To what extent do existing reserve products provide System Operators with the most cost-effective means of maintaining reliability during VER ramping events? To what extent would the other reforms discussed herein, if implemented, mitigate the need for additional reforms to existing reserve products without adversely impacting system reliability?

Would a following or similar reserve product facilitate the reduction of costs associated with ensuring that sufficient reserve capacity is available to address the uncertainty and variability associated with VERs? If so, what are the ideal characteristics of such a product?

It is expected that five-minute economic dispatch, existing reserve products and regulation products would provide adequate load/VER-generation following capability under a wide range of typical operating conditions in New England. Under unusual situations with high

⁴³ As discussed in Section V.B.1, implementation of shorter scheduling intervals requires technology and rule changes across balancing areas. Such changes, however, can be accomplished without the need to consolidate balancing authority areas, particularly if an area already is of the size and geography that the Commission has determined meets the requirements of an RTO and ISO.

⁴⁴ ACE Diversity Interchange is the pooling of Area Control Errors (ACE) to take advantage of control error diversity (momentary imbalances of generation and load).

⁴⁵ For a short time between May 1, 1998 and December 1, 2000 there was a service known as In Service that used a pro forma type of transmission service for transactions over the New York and New Brunswick AC ties into New England. In Service, however, was eliminated in *New England Power Pool*, 93 FERC ¶ 61,195 (2000), *order on reh'g*, 96 FERC ¶ 61,087 (2001). Also, in 2004, the Commission accepted filings by the ISO and NYISO to eliminate Through-and-Out Service charges in the New England/New York regions. *See ISO New England Inc.*, 109 FERC ¶ 61,147 (2004).

levels of VER penetration, that might not be sufficient, and it might be appropriate to increase the amount of reserves carried. This does not necessarily entail a new or separate reserve product; but rather, an expanded use of the existing reserve products. However, detailed studies, such as the NEWIS, should be conducted to determine if the existing products can meet the requirements in a cost-effective manner. Results from the NEWIS should illuminate this issue further for the New England area.

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?

See responses provided in Section V.A, regarding forecasting tools and processes.

Existing contingency reserve products were designed to be utilized by System Operators to respond to disturbances (i.e., contingency events) due to a loss of supply and to assure system reliability.⁴⁶ Does or should the definition of a contingency event include extreme VER ramping events? If so, would an additional level of contingency reserves be needed to achieve the same level of system reliability? In responding to this question, please include a proposed definition of “extreme ramping event.”

The NEWIS Technical Report provides a concise definition of an operational ramp – “a change in power output [or consumption] that has a high enough amplitude over a short enough period of time to cause short-term grid management issues.”⁴⁷ System Operators must ensure that sufficient resources are available to compensate for ramps. It should be noted that ramps, in and of themselves, do not create substantial concerns with respect to operational reserves; instead, it is the not-forecasted or imperfectly-forecasted ramp that impacts reserves requirements. Put simply, if a forecasting system were able to accurately predict the magnitude, timing, duration, and location of ramps (due to transmission constraints), a special focus on

⁴⁶ Disturbance Control Performance, Standard No. BAL-002-0 (Apr. 1, 2005).

⁴⁷ NEWIS Technical Report at 83.

operational reserves would not be required to address VER ramping, since other resources could be scheduled to mitigate VER ramping

Because load forecasting is well-developed and quite accurate, the source of ramping uncertainty will primarily be caused by VERs in areas with a high penetration of VERs. At this time, it is difficult to predict the amount of VERs (versus, for example, the system peak load) that will cause VER ramping uncertainty to become a concern. This underscores the need for areas to perform operational studies such as the NEWIS. The results of the NEWIS will help assess the tipping point for New England, which will differ depending on each Balancing Authority Area's resource mix and operational practice. Generally, Balancing Authority Areas with more flexible legacy generation and markets and more diverse (*i.e.*, easier to forecast) portfolios of VERs will generally tend to have lower ramping requirements. As VER forecasting improves, so too will the ability of the system to mitigate VER-induced ramping using hourly and sub-hourly energy markets. Operating reserves currently provide the resources that are necessary to secure the reliability of the New England and neighboring system in order to guard against credible events that might occur. They provide the extra protection we would not otherwise need just to meet instantaneous load requirements, and allow the capability to respond to the unexpected events that occur every day on the system including changes in loads and supply. Specifically, operating reserves provide the protection to address the following requirements specified in the ISO's Operating Procedure No. 8, Operating Reserve and Automatic Generation Control

Loss of generating equipment within the New England Control Area/Balancing Authority Area (CA/BAA) or within any other Northeast Power Coordinating Council Inc. (NPCC) CA/BAA.
Loss of transmission equipment within or between NPCC CA/BAA's that might result in a reduction of energy transfer capability within the New

England CA/BAA or between the New England CA/BAA and any other CA/BAA.
Regulation in the New England CA/BAA.
Errors in forecasting New England CA/BAA loads.⁴⁸

It would be appropriate to use operating reserves to respond to extreme ramping event given: (a) what constitutes a “ramping event”, (b) the low combined probability of a simultaneous not-forecasted VER-induced ramp and another event that operating reserves are meant to address, (c) the nature of the resource provided by VER, and (d) the, now standard, view of analysis of power system impacts from VER being defined by the “net-load” concept whereby the VER generation within an area is subtracted from that area’s “native” load in order to present the effects on an area’s dispatchable generation. Higher penetration of VER, however, may require the use of historical and statistical analysis to determine the amount of reserves requirements. With this methodology, the amount of required reserves may increase as a function of the state of the power system and its short-term forecasted state, including such variables as the amount and type of legacy generation, the topology of the transmission system, the largest conventional contingency, the system load, potentially the amount of available demand response, and the amount of VER generation.

Should a new category of reserves, that would be similar to contingency reserves, be developed to maintain reliability during VER ramping events in a cost effective manner? If so, what benefit would such reserves provide to System Operators and customers?

It is unlikely that a new reserve product would be more efficient at maintaining reliability during VER ramping events than a modification or increase in the quantity of the current reserve products to respond to all significant and unexpected resource imbalances, including those attributable to VER forecasting uncertainty. The dispersed nature of large-scale VER prime-

⁴⁸ ISO New England Operating Procedure No. 8, Operating Reserve and Automatic Generation Control at p.3, available at: http://www.iso-ne.com/rules_proceeds/operating/isone/op8/op8_rto_final.pdf.

movers (*i.e.*, wind or water kinetic and/or potential energy, solar insolation, etc.), combined with the use of effective forecasting and the existence of hourly and sub-hourly energy markets, assists the existing reserve products in managing the uncertainty associated with VER ramping, as well as other resource imbalances.

Could the expanded use of reserve-sharing programs between balancing authorities contribute to lowering the costs associated with integrating VERs? If so, how?

Expanded use of reserve-sharing programs can potentially reduce the amount of within-area based reserves that individual Balancing Authority Areas require. Reserves-sharing programs can contribute to: returning frequency to normal levels; faster unloading of ties; reduced requirements for the start-up of multiple fast-start resources in one area when spinning reserves can be used from multiple areas, etc. Accordingly, expanded use of reserve-sharing programs, by definition, may reduce the amount of within-area based reserves that are required to provide for VER uncertainty-related imbalances. This should result in less uplift by reducing additional reserves that a Balancing Authority Area might need to carry, which, in turn, could reduce costs.

Entities that enter into reserves-sharing agreements need to understand not only the effects of entering into reserve-sharing agreements, but also the effects and character of additional variability and uncertainty that may increase as the penetration of VERs increase. VER penetration may differ between entities in a reserve-sharing program and the VER penetration within those entities may change significantly over the course of time. The nature of the typical VER is such that neighboring Balancing Authority Areas may be able to use real-time information cues from their neighbors in order to further reduce the uncertainty associated with VERs. For example, as a weather front moves across an area, the timing of its effects on the

wind generation levels could possibly be useful information to other entities in a reserve-sharing program.

Should the ancillary services provisions of the pro forma OATT be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs? If so, how?

The New England Markets procure a full suite of energy and ancillary services products through the wholesale electricity market that can accommodate changes to reserve requirements caused by VER integration.

Are there new sources and/or providers for reserve products (such as inter-balancing authority pooling arrangements, demand response aggregators and/or storage devices) that can be used to maintain reliability and lower reserve costs during VER ramping events? Based on experience, are there characteristics of these new sources of reserves that would positively or negatively impact their ability to match the reserve product needs presented by the variability of VERs?

Theoretically, any resource that is willing and able – within the required timeframe – to increase generation or decrease load once in receipt of a dispatch instruction from the System Operator could be used to provide reserves to manage VER variability, so long as it can meet the performance requirements established for the needed services. In New England, for instance, Forward Reserves may be provided by any resource that satisfies the criteria specified in the Market Rules. These criteria include:

- (i) If the Resource is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM 30 [established] value . . .
- (ii) If the Resource is expected to be on-line during a Forward Reserve Delivery Period, it must be able to produce the energy equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch rang;
- (iii) If the Resource is an Asset Related Demand, it must have an audited CLAIM10 and CLAIM30 [established] value . .
- (iv) the Resource must be fully listed as an Installed Capacity Resource during the delivery hour for which it has been assigned;
- (v) The Resource must be able to follow ISO Dispatch Instructions;
- (vi) The Resource must have Electronic Dispatch Capability; and
- (vii) The Resource must meet the technical requirements associated with the provision of Forward Reserve as specified in ISO New England Operating Procedure No. 14, Technical Requirements For Generation, Dispatchable and

Interruptible Loads.⁴⁹

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?

VERs with no associated storage capability might be technically capable of providing reserves, but they tend to operate at their maximum possible output based on existing wind/water/solar conditions. There is little reason to do otherwise, unless the value of providing reserve capability at a given moment exceeded the value of producing energy. This would not normally be the case, but could occur in rare situations.

VERs with some associated storage (*e.g.*, a hydro facility with a small reservoir) might well be able to use the storage to provide reserves. Many developers and users of VER technologies are still in the process of understanding and considering the types of power system products and revenues that their VER technologies may be able to provide. Pilot programs such as the ISO's Alternative Technology Regulation and Demand Response Reserves pilot programs provide the opportunity for VERs (and other technologies) to research and demonstrate their capabilities.

To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?

It would be prudent for reliability of the bulk electric system that all resources be required to have a governor and be able respond to frequency variations. All resources should have the capability to be retrofitted in order to provide ancillary services if it is deemed appropriate at some future date.⁵⁰ To that end, all resources should be required to: (1) have the

⁴⁹ ISO Tariff, Section III.9.5. *See also*, ISO New England Manual For Forward Reserve, Manual M-36, available at http://www.iso-ne.com/rules_proceeds/isone_mnls/index.html.

⁵⁰ *See* NEWIS Technical Report at 9.

capability to accept control signals from the System Operator and utilize these signals to control various plant output (*e.g.*, real power), and (2) have the capability to communicate signals to the System Operator, as appropriate, in order to indicate plant status, availability of the plant to provide power system products, and acknowledge receipt of control signals.

The characteristics of VER technology affect their ability to provide power-related products. First, VERs often are semi-dispatchable in their normal mode of operation. For example, at any given instant a wind plant may technically be able to decrease the amount of power below its theoretical maximum production potential (given the ambient conditions that it is experiencing), but will not be able to produce more power than its theoretical maximum. In order to provide power-related products like Frequency Response in a bi-directional manner, the VER would need to be pre-postured at a sub-optimal generation stance (*i.e.*, at less than the theoretical maximum). While this pre-posturing is feasible, it may be difficult to economically justify under most circumstances.⁵¹ Having said this, semi-directional power-related products (where the resource would reduce power production for short time periods) could be much less subject to economic penalties.

Second, some types of VERs incorporate a degree of storage (*e.g.*, in the DC bus of a back-to-back power-electronics converter of a typical variable-speed wind turbine, or the inertia of the blades and rotor) and thus may be able to provide power-related products for short time periods with no loss of production and hence no economic penalty (*e.g.*, inertia – synthesized or real – and, given enough storage, perhaps regulation). Moreover, VERs sited at the edges of the power system where there are weak connections to the rest of the system may be well-situated,

⁵¹ See NEWIS Technical Report at 50.

and have an incentive, to provide ancillary services (*e.g.*, voltage regulation in weak portions of the grid).⁵²

Should the Commission revisit the reactive power requirements set forth in Order No. 661?⁵³ 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?

The Commission should revisit the reactive power requirements established in Order No. 661, and establish a dynamic reactive power management requirement for VERs.⁵⁴ Currently, per Order No. 661, wind generation resources are required to meet a power factor standard if the transmission provider can show in the system impact study that reactive power capability is necessary to ensure the safety and reliability of the transmission system. With the required showing, a wind generation resource would be required to maintain a power factor range within the range of 0.95 leading to 0.95 lagging to be measured at the point of interconnection.

In practice, this case-by-case approach has been problematic. It underestimates the prevalence of the situation where multiple wind generation resources are developed in close proximity to each other, which is becoming the dominant development pattern. This development pattern, combined with the case-by-case approach, results in different requirements for wind generation resources located in the same area.

It is important to recognize that the transmission system is dynamic and requires flexibility in the use of bulk power system components to adapt to changing conditions. This flexibility is limited as the amount of resources on the transmission system that cannot participate effectively to support the system functions (*e.g.*, by providing ancillary services) grows. Wind generation resources, for example, are often connected into weak areas of the

⁵² See NEWIS Technical Report at 5.

⁵³ Order No. 661 at PP 50-51.

⁵⁴ *Id.*

transmission system, and an appropriate voltage schedule can improve both performance and security of the system. Currently, traditional generation is required to provide voltage regulation capability. VERs, in general, should be treated no differently than any other generating resource. Recent experience shows that wind plants, for example, can be designed to meet the same requirements as those established for traditional generation. In fact, the overwhelming majority of wind generation resources that are being installed or planned for installation in the United States are variable-speed wind turbines that typically have the capability to provide reactive power management. VERs should be required to meet a power factor standard so that they can participate as an equal partner in the power system, with the result that the transmission system can operate reliably even with high penetrations of VERs. A standardized requirement that follows good utility practice also allows VERs to standardize their equipment, resulting in a more level playing field and likely cost reduction for the reactive power management technology if deployed on a wider basis under a consistent standard.

F. Capacity Markets

Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?

All resources should be rated for capacity purposes based on the amount of load they are effectively able to support. The current best practice in this area is a stochastic analysis often referred to as “Effective Load Carrying Capability.” While this technique may produce values that differ most from nameplate ratings for resources with varying and unpredictable output, it should ideally be applied consistently to all resource types. Even traditional thermal generation is sometimes unavailable due to maintenance requirements and forced outages. To use inconsistent rating rules based on the type of generation technology could threaten reliability where “expected” production is not actually available in practice, or lead to higher than

necessary capacity costs if resources are paid for providing benefits they are not truly able to deliver.

Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?

The New England Market Rules do not require VERs to participate in the DAM in order to be counted as a capacity resource. As briefly mentioned in Section V.C, however, the ISO will be undertaking an analysis of the possible benefits of changes to the Market Rules that would expose VERs to both the price risk of day-ahead and real-time energy deviations plus a share of the cost of managing uncertainty as captured in the Real-Time NCPC Charges.

As more VERs choose to become capacity resources, will existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services? If not, what reforms may be necessary? For instance, should the Commission examine formation of forward ancillary services capacity markets?

The New England Markets adequately compensate resources that can meet the requirements of a capacity resource. Additionally, as market conditions change, the value of capacity may change: New England Markets provide for the transparent determination of the value and will send the appropriate market signals to address any changes in the value of capacity.

Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?

New England's LFRM is a form of capacity market that is designed to create incentives for a particular type of flexible resource. It ensures that sufficient resources are available to respond on short notice when a contingency occurs. As noted in Section V.E, however, it is difficult to predict the level of VER penetration in a region (versus, for example, the system peak

load) that would result in VER ramping uncertainty becoming a regional concern. The ISO's NEWIS seeks to identify this tipping point for the New England area.

The impact of ramping events is one of the potential concerns that the ISO is considering in anticipation of increased VER penetration. As mentioned in Section V.E, the ISO will need to identify the impacts of VER characteristics on the requirements for mitigating ramps and may need to increase the amount of reserves that are procured.

G. Real-time Adjustments

How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?

Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?

The ISO uses a security constrained economic commitment and dispatch system to manage congestion. Once dispatchable resources have been dispatched down to Economic Minimum ("EcoMin"), only self-scheduled resources (*i.e.*, resources that have effectively offered at \$0 per megawatt-hour) remain. The ISO curtails those resources with the greatest impact on the binding constraint first, giving curtailment priority to resources that offered and cleared in the DAM. In certain time-sensitive situations, the ISO curtails those resources that can reduce output most rapidly. Generally, these are VERs. This practice may not necessarily lead to the most economically efficient outcomes. It would be preferable if curtailment decisions could be handled largely or exclusively through economic dispatch. That requires resources to be able to express their willingness to be curtailed through their economic offer parameters, including specifically the ability to submit negative energy offers.

The ISO's redispatch and curtailment practices have not changed with the advent of VERs; however, because VERs in New England tend to be located in remote areas with limited transmission capability, redispatching has increased.

Some RTOs/ISOs will redispatch VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?

Each RTO/ISO needs to examine and decide on the most effective means of mitigating any negative effects and capitalizing on any benefits associated with integrating VERs. Each market is different so it is difficult to apply a “one-size-fits-all” approach. In general, though, it appears desirable to allow resources to signal their willingness to curtail through a mechanism that results in a smooth, robust process that is easy to implement in an automatic and transparent fashion.

Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments 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?

The ISO has yet to experience significant issues with minimum generation events,⁵⁵ whether contributed to by VERs or otherwise. However, higher VER penetration is likely to exacerbate minimum generation events at night, when load drops and wind resources typically produce their maximum output. It may be appropriate to offer incentives for resources to indicate their willingness to curtail, *e.g.*, through negative offers.

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?

VERs already have the ability to respond to dispatch instructions in the downward direction and usually very effectively. VERs, however, are not able to respond in the upward

⁵⁵See ISO New England Manual for Definitions and Abbreviations, Manual M-35, available at http://www.iso-ne.com/rules_proceeds/isone_mnls/index.html (explaining minimum generation event as occurring under conditions of light loading where at least one generator is requested to operate at or below EcoMin in order to maintain secure system operation).

direction without wasting their fuel source instead of using it when available. This inflexibility could be mitigated by the VER combining its resource with some type of storage technology. Like conventional resources, VERs should be required to offer dispatch capability within their design parameters, which ideally should be expressed in an offer to provide particular services and respond in accordance with the needs of the Balancing Authority Area.

VI. CONCLUSION

ISO-NE respectfully requests the Commission to consider these comments.

Respectfully submitted,

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