UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources	)))	Docket No. RM10-11-000

COMMENTS OF THE BONNEVILLE POWER ADMINISTRATION

On January 21, 2010, the Federal Energy Regulatory Commission (the "Commission") issued a Notice of Inquiry ("Notice"), seeking comment on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources ("VERs") into the electric grid, and whether reforms are needed to eliminate those barriers. The Bonneville Power Administration ("BPA") appreciates the Commission's thoughtful and detailed focus on these important and timely issues affecting the future of the nation's electricity industry. BPA submits the following comments in response to the Notice.

BPA is a Federal power marketing administration established to market wholesale electric power from the Federal hydroelectric projects in the Pacific Northwest. BPA currently markets power from 31 Federal hydro projects and some non-Federal projects and operates over 15,000 miles, or approximately 80%, of high-voltage transmission lines in the region. BPA provides transmission on an open-access basis. BPA's service territory covers Washington, Oregon, Idaho, western Montana, and portions of California, Nevada, Utah and Wyoming. BPA's wholesale power customers include public utilities, public utility districts, municipal districts, public cooperatives, investor-owned utilities, and a few large industrial customers.

As of 2010, BPA has approximately 2,800 MW of wind facilities on its system. Most of those facilities are located in a relatively small area near the Columbia River Gorge. With a peak balancing authority load of 10,500 MW and a minimum light load of 4,000 MW, the wind penetration in the BPA balancing authority is among the highest in the nation.

Primary Messages for the Commission Notice on Variable Energy Resources

BPA supports the reliable and cost-effective integration of VERs. As the Commission recognizes, rapid development of VERs raises issues regarding reliability, cost allocation, and the roles and responsibilities of balancing authorities. The need to clearly define balancing authority roles and responsibilities is especially important to BPA, because approximately 80 percent of the almost 2,800 MW of wind generation currently on BPA's system is exported to other balancing authorities, and BPA's preference customers should not bear costs of integrating wind generation that is exported to serve load outside of BPA's balancing authority. The challenges and cost allocation issues associated with the management and export of significant amounts of wind generation from BPA's balancing authority strongly influence BPA's comments in response to the Notice. Although increased balancing authority coordination and changes in market design may address some of these issues over time, BPA's comments are based on the markets and structures currently in place in the Pacific Northwest.

BPA's comments address issues substantially more important than just BPA's parochial interests. As VERs are increasingly developed in locations that are remote from load centers, one of the keys to successful large-scale expansion will be establishment of policies, regulations, and cost-recovery mechanisms that ensure that exporting balancing authorities are not exposed to additional costs or reliability risks. If host regions for VERs experience reliability risk or increased costs for resources that are being exported, it will become increasingly difficult to build new projects in those regions, potentially limiting access to cost-effective resources. Although no single reform will address all issues, a combination of clarifying balancing authority responsibilities with respect to providing the capacity reserves necessary for VER balancing, promoting targeted improvements in VER forecasting and scheduling accuracy, and increased balancing authority coordination will help facilitate the integration of VERs in a manner that does not create cost shifts or increased reliability risk. With these points in mind, the following list summarizes the primary messages in BPA's comments in response to the Notice:

1. Cost Allocation

Currently, it is possible to interpret Schedule 9 of the Commission's *pro forma* tariff to mean that balancing authorities in which VERs are physically interconnected have the default responsibility to provide balancing reserve capacity necessary to maintain reliability when VER ramps (up or down) result in output that deviates from scheduled levels *even if such output is exported to serve load in other balancing authorities.* Current policies are leading to duplicative and inefficient carrying of reserves by both source and sink balancing authorities as well as creating cost and reliability risks for host balancing authorities from which VERs are being exported. The Commission should reevaluate the roles and responsibilities of source and sink balancing authorities. Source balancing authorities should not be required to act as default suppliers of balancing reserves for VER exports, but rather should be allowed to clearly define and enforce limits to their balancing reserve obligations.

Rather than serving as default suppliers, source balancing authorities should strive to facilitate options for VER exporters to acquire balancing reserve capacity from alternative sources. Such options could include scheduling and operational tools such as self-provision of balancing reserve capacity or intra-hour scheduling and dynamic transfers to the extent that these options do not adversely impact system reliability and the value of these options does not exceed the cost of making them available.

The owners and operators of VERs should develop balancing plans that clarify the VERs' preferred source(s) for procuring balancing reserve capacity. These balancing plans should be submitted to source balancing authorities during the interconnection process and on a regular basis thereafter.

If, after considering other options, the VER submits a balancing plan indicating that it still prefers to procure some or all of its balancing capacity from the source balancing authority, the source balancing authority can enter into a commercial transaction for such balancing capacity with full cost recovery and risk protections for its preference or native load customers. The obligations of the source (exporting) balancing authority should be limited to the quantity of capacity for which it has contracted with the VER. If the VER's chosen portfolio of balancing capacity (including purchases from the source balancing authority) is insufficient to manage the balancing needs of the VER, it is the VER operator or buyer and the sink balancing authority that should be accountable for making up any balancing shortfalls. This distinction between being a default supplier as opposed to a fully compensated party to a clearly defined and delimited commercial transaction is essential to the sustainable growth of VERs in exporting regions.

Balancing authorities with substantial amounts of VERs relative to their available balancing reserves likely will require operational and reliability protocols to enforce generation reductions or schedule curtailments when VERs cumulatively operate substantially outside of schedule and available balancing reserve capacity is close to being exhausted. A source balancing authority can use such protocols to preserve the reliability of its system and limit its provision of balancing reserve capacity to its contractually defined obligations. In collaboration with VER sellers and purchasers, balancing authorities can use such protocols to help achieve a balance between quality of service and cost (*e.g.*, carrying a smaller quantity of balancing reserves reduces costs but increases the likelihood of generation reductions or schedule curtailments and *vice versa*). This balance can be defined by the VER operator and purchaser based on their willingness to pay for maintaining reserves. Over time, emerging mechanisms such as intra-hour scheduling may mitigate the impacts of schedule curtailments on receiving balancing authorities and allow for more efficient and economical provision of balancing reserve capacity.

As increasing amounts of VERs locate within a source balancing authority and export output to a sink balancing authority, the VER balancing reserve capacity requirements may ultimately exceed the capability of the source balancing authority's available generating resources. If this occurs, the source balancing authority should have the ability to acquire additional balancing reserve capacity in a cost-effective manner and allocate the incremental costs and stranded cost risks to the class of customers driving the need for the additional balancing services.

If buyers and sellers of VER generation have adequate choices for providers of balancing reserve capacity, it may be possible and appropriate for source balancing authorities, which have historically provided such capacity at embedded cost rates, to be given the discretion to charge incremental or market-based rates for the use of their balancing reserve capacity. This may be a way to encourage the development of cost-effective balancing reserve capacity resources and new markets as well as preventing the hyper-concentration of VER variability on individual systems.

2. Forecasting

Investments in VER forecasting can provide substantial value. Forecast uncertainty and inaccurate scheduling are among the largest contributors to balancing reserve capacity requirements for VERs. Improvements in forecasting and scheduling accuracy can reduce the amount of balancing reserve capacity that balancing authorities will need to carry to balance VERs, which will help reduce integration costs. Data collection can be improved through collaboration with the National Weather Service. Sharing of meteorological data should be strongly encouraged but not mandated.

A few years ago, BPA eliminated the penalty band of its generation imbalance rate in order to encourage wind power development. With the rapid increase of wind on BPA's system and the well-documented importance of scheduling accuracy, BPA believes it may have gone too far. As a result, BPA has reinstated penalties for extended (*i.e.*, four hour) deviations from scheduling accuracy in the same direction. BPA is not certain that it has found exactly the right solution but believes it is necessary to send price signals regarding the cost of scheduling inaccuracy where it potentially is within the control of the VER to improve. The party that can best improve scheduling accuracy should receive the price signal. VERs or the loads served by VERs must bear the energy and capacity costs associated with inaccurate schedules. However, even with state-of-the art forecasting, balancing authorities will still need mechanisms to manage "tail events" (*e.g.*, infrequent, but very large unscheduled ramps of VER output).

3. Intra-Hour Scheduling

Intra-hour scheduling has the potential to help better manage the costs and operational impacts of VER generation imbalances. Several transmission providers in the Pacific Northwest are already working together to accelerate the development of intra-hour scheduling, including the adoption of common business practices, dynamic transfers and an intra-hour bulletin board to facilitate within-hour transactions. Given these collaborative and ongoing efforts, the Commission should encourage but not mandate intra-hour scheduling and allow regional cost-benefit analysis.

4. Balancing Authority Coordination

Increased balancing authority coordination is under consideration in a variety of forums across the Western United States. Given the rapid increase in VERs in the Northwest over the past five years, there is potentially much greater value in balancing authority coordination than there was during previous attempts to address market design in the region. This is particularly the case with respect to the potential benefits of working across existing balancing authorities to address within hour variability. That said, additional changes to market design involving the creation of independent entities or Regional Transmission Organizations ("RTOs") should be evaluated against the benefits of fully implemented bilateral mechanisms such as the ColumbiaGrid, Northern Tier Transmission Grid, and WestConnect Joint Initiative. The Commission should encourage, but not mandate, the virtual or physical consolidation of balancing authorities while relying on regions throughout the country to determine institutional structures that create the most value.

5. Market Impacts of VERs

VERs that have little demonstrable capacity value should only be allowed to participate in day-ahead markets to the extent that they can support their uncertain and variable generation with other dispatchable capacity resources or products. The Commission should not institute measures that relieve some parties in a commodity market of financial risk at the expense of other market participants. To the extent that risk is different for different products, that risk should be transparent and should be reflected in the value that the market assigns to that product.

Negative market prices are raising concerns about VER production at times when market signals tend to incent traditional generators to reduce generation output or shut down, such as during light load hours or fish-related spill conditions in a hydro-based system. During times when a balancing authority is operating to meet other mandatory non-power constraints such as flood control or Endangered Species Act requirements, continued operation of the VERs can increase risks to system operations and violations of other mandates. BPA believes that balancing authorities should not be obligated to pay VERs to reduce generation output when necessary to meet statutory, environmental, or reliability obligations.

6. Voltage and Reactive Power Requirements

BPA supports the North American Electric Reliability Corporation's ("NERC's") recommendation to develop consistent interconnection standards to ensure low-voltage ride-through, reactive/real power control, and frequency and inertial response requirements for all generation technologies.

BPA'S COMMENTS

BPA's comments are organized into three main sections. Section I provides background regarding the integration of VERs on BPA's system. Section II includes a policy paper describing BPA's perspective on some of the biggest challenges that BPA and the Pacific Northwest face with respect the future of VER development. Section III includes BPA's responses to the specific questions in the Notice. The policy paper in section II provides context for BPA's responses to the specific questions in section III, but it does not necessarily address all of the issues raised in the questions in section III.

I. BACKGROUND

A. Regional Collaboration of Integration of VERs Since 2005

In 2005, the Northwest Power and Conservation Council (the "Council") released its 5th Power Plan, calling for up to 6,000 MW of regional wind development over the next 20 years. In response, BPA and the Council co-sponsored the Northwest Wind Integration Action Plan ("Action Plan"). This collaborative effort brought together the region's utilities, wind developers, regulators, renewables advocates and other stakeholders to determine whether it was technically feasible to integrate 6,000 MW of wind energy into the Northwest grid. The Action Plan also identified what it would take, in terms of infrastructure investment, operational changes, cost-recovery, and technology innovation to make wind work for the Northwest in a reliable and cost-effective fashion.

When the Action Plan was released in March 2007, it concluded that there were no fundamental technical barriers to integrating 6,000 MW of wind in the Pacific Northwest, but that realizing this objective would require: new transmission investments, better utilization of the region's non-hydro balancing resources through more robust voluntary markets for wind integration services, additional coordination between the region's multiple balancing authorities, improved analytical and forecasting techniques, and new cost-recovery mechanisms to ensure that the costs of wind integration services are appropriately borne by those creating the demand for such services.

The Pacific Northwest has since made substantial progress in implementing the Action Plan's recommendations. With respect to infrastructure development, several of the region's utilities are constructing or planning new transmission facilities that will help integrate thousands of megawatts of VERs. BPA's 2008 Network Open Season process, for example, resulted in signed commitments for 4,700 MW of new transmission service and, with the assistance of the American Recovery and Reinvestment Act of 2009 funding to expand BPA's borrowing authority, BPA is now building the 79-mile McNary-John Day 500 kV transmission line that will help bring additional wind energy from the eastern part of the Columbia River Gorge to load centers further west. BPA also has begun environmental review on three other proposed 500-kV projects totaling about 145 miles as a result of the 2008 Network Open Season. In the interim, BPA has made over 585 MW of offers of conditional firm transmission service, two-thirds of which will help to support the transmission of wind generation.

With respect to system operations, there have been several positive developments. In 2006, a number of balancing authorities in the region came together to develop an operational tool called Area Control Error Diversity Interchange. Through this tool, balancing authorities located throughout the Western Interconnection share momentary imbalances or control errors. This reduces control burden on generators, resulting in savings in operation and maintenance costs, improvements in control performance, and reductions in sensitivity to VER output. This tool was implemented at very low cost without requiring additional governance or regulatory oversight. Recently there have been some issues regarding application of BAL-001-0.1a to the initiative, but these issues should be resolved in the near term. This accomplishment is just one of many examples of regional coordination and problem solving efforts related to system operations that has defined the Pacific Northwest for many years.

The region is also advancing in the area of intra-hourly scheduling. A Joint Initiative among ColumbiaGrid, Northern Tier Transmission Group, and WestConnect has developed generic business practices for intra-hour transmission scheduling.[1] BPA and several other regional utilities have posted customized versions of those business practices and a voluntary, bilateral intra-hour market has begun to develop in the Northwest. The joint initiative is also developing an automated Dynamic Scheduling System as well as an electronic bulletin board to help reduce transaction costs and increase liquidity in the intra-hour market.

Based on the Action Plan and regional dialogue, the region has identified many of the issues associated with VER integration, and is actively working collaboratively to find and implement solutions. Through the Joint Initiative, the Western Electricity Coordinating Council ("WECC"), and other regional forums, the region's balancing authorities are now discussing other ways to build on the existing platform of collaboration to support wide-area optimization in ways that are consistent with regional values and regulatory and statutory obligations.

[1] These efforts are described in detail in the "Comments of the Joint Initiative Facilitators" filed in this docket.

B. Recovering the Costs of Balancing Reserve Capacity

In addition to operational and technical issues, the Action Plan identified the development of mechanisms to recover the costs of wind integration as a threshold issue. In 2007, BPA determined that a new rate was necessary to recover the costs of carrying capacity reserves to balance the within-hour variability of wind. Historically BPA has relied on the Federal Columbia River Power System ("FCRPS") to provide the capacity needed to balance variation in wind generation within the hour. BPA generally refers to the capacity reserve needed to account for within-hour variability as "balancing reserve capacity." The large-scale export of wind generation out of the BPA balancing authority has placed enormous pressure on the balancing capability of the FCRPS, because BPA stands ready to provide balancing reserve capacity and energy to support delivery of large quantities of wind to other balancing authorities. When the large, geographically-concentrated wind fleet in BPA's balancing authority experiences a significant ramp event (up or down), BPA sees substantial variations between the wind hourly schedules and the actual performance of the generators, which contributes substantially to the need for balancing reserve capacity. This balancing reserve capacity includes three components: regulation reserve (moment to moment balancing), following reserve (moment to 10 minute variation balancing), and imbalance reserve (balancing the difference between schedule and actual for the hour). BPA notes that in some forums, it is common to use the term "regulation" as a proxy for the totality of the within-hour balancing requirements for VERs, but through its rate cases and other operational forums, BPA has very explicitly disaggregated the total VER within-hour balancing requirement into these three components.

BPA first established a wind integration rate for Fiscal Year ("FY") 2009 to better align cost causation with cost allocation and send a price signal for the costs of balancing reserve capacity in the face of impending limits on FCRPS capability. BPA's first iteration of the wind integration rate did not include costs of the imbalance reserve component of balancing reserve capacity. Once BPA began work on the rate for FY 2010-11, its efforts quickly indicated that a substantial rate increase would be necessary because of the "imbalance reserve" component of balancing reserve capacity. BPA determined that a significant, and previously underappreciated, driver of the imbalance component of balancing reserve capacity was the inaccuracy of the wind schedules in BPA's balancing authority. Inaccurate scheduling by the wind fleet increased the need for balancing reserve capacity and the overall cost of balancing reserve capacity by a substantial amount. These concerns about the cost of inaccurate scheduling were enhanced by the fact that BPA forecasts indicated that wind generation in the balancing authority would increase significantly in FY 2010-11.

Quantifying the cost of inaccurate scheduling by a rapidly growing wind fleet got the attention of the regional wind community and other key stakeholders, and these groups immediately began to communicate the importance of high quality wind forecasting and accurate scheduling. Soon after publication of BPA's proposed FY 2010-11 wind integration rate proposal, BPA began to observe improvements in scheduling accuracy. Within three months, scheduling accuracy had improved substantially. BPA ultimately set its FY 2010-11 rate based on assumptions about more accurate scheduling by the wind fleet, which reduced the rate substantially compared to the initial proposal.

C. BPA's Wind Integration Team and Dispatcher Standing Order 216

BPA has assembled a cross-agency Wind Integration Team ("WIT") to further address the technical issues identified in the Action Plan, FY 2009 rate proceeding, and other regional forums. One of the first accomplishments of the WIT was the development of operational and reliability protocols designed to maintain system reliability when wind variability exhausts the incremental and decremental balancing reserve capacity established on a planning basis.[2] The WIT developed these protocols after BPA began analyzing the FCRPS' capability to provide sufficient balancing reserve capacity to maintain reliability during extreme wind ramps. BPA codified the protocols in Dispatcher Standing Order 216 ("DSO 216") in October 2009.

The DSO 216 protocols have two essential features: when *unscheduled increases* in wind generation and load exhaust the FCRPS' decremental balancing reserve to ramp Federal generation down, dispatchers send reliability directives via electronic signals to the wind fleet requiring reductions in wind output (feathering) to preserve load and resource balance within the BPA balancing authority. When *unscheduled reductions* in wind generation and load exceed the FCRPS' incremental balancing reserve to increase Federal generation to respond with imbalance energy, dispatchers adjust wind transmission schedules down to reflect the lower wind output levels. For wind generation exports in these extreme under-generation cases, the load serving entities in the receiving balancing authorities must rely upon their own resources to make up any difference. BPA activated the current DSO 216 protocol in October 2009, and so far the DSO directives have only been activated a few times each month.

Although BPA developed DSO 216 initially as a reliability backstop tool, it has served a commercial purpose by allowing BPA and wind generators to balance quality of service with costs. In the last rate case, BPA forecast the amount of balancing reserve capacity needed to

[2] Incremental reserves are reserves required to maintain load-generation balance when an under-generation situation exists within the BPA balancing authority area. In an under-generation situation, instantaneous loads are higher than planned or the instantaneous wind generation is lower than planned. Under these circumstances, the FCRPS generation must automatically increase to maintain system balance. The incremental reserve is the amount that the FCRPS must be capable of instantaneously increasing generation. Conversely, decremental reserves are reserves required to maintain load-resource balance when an over-generation situation exists within the BPA balancing authority area. In an over-generation situation, instantaneous loads are lower than planned or the instantaneous wind generation is higher than planned. Under these circumstances, FCRPS generation must automatically decrease to maintain system balance. The decremental reserve is the amount that the FCRPS must be capable of instantaneously decreasing generation. BPA forecasts the incremental and decremental balancing reserve requirement on a two-year planning basis coinciding with its rate proceedings.

firm up hourly transmission schedules from VERs during the rate period. As described above, the assumption about the scheduling accuracy of the wind fleet was a primary driver of the amount of capacity that BPA would need. Wind developers and operators encouraged BPA to assume that the wind fleet would schedule more accurately during the rate period than the fleet had historically, because assuming more accurate schedules would reduce the overall amount and cost of balancing reserve capacity that BPA would make available. In other words, they advocated that BPA should carry—and charge—for a lower quantity of available balancing reserve capacity. In exchange for BPA limiting the wind integration rate increase by making less balancing reserve capacity available, however, wind generators essentially were accepting a lower quality of service because the likelihood of feathering or curtailments under DSO 216 would increase.

The tradeoff between cost and quality of service through the amount of balancing reserve capacity available before BPA applies DSO 216 has raised questions about the deployment of other types of reserves for wind balancing. Because substantial VER generation is exported from BPA's balancing authority, BPA has called upon DSO 216 to "clip the tails" of wind ramps at times to maintain reliability of the BPA balancing authority when the planned balancing reserve capacity is exhausted. The use of DSO 216 to curtail firm transmission schedules associated with exported wind energy is forcing re-examination of the traditional ways of carrying contingency reserves for VERs. BPA addresses this issue in Part II below.

In collaboration with regional stakeholders, the WIT is also developing new wind forecasting and situational awareness tools for dispatchers. The WIT is managing the development and implementation of three pilot projects related to wind integration in the areas of dynamic transfer, intra-hourly scheduling, and customer self-supply of balancing reserve capacity.

II. MAJOR POLICY POSITIONS

Despite the region's considerable progress on the wind integration front, there remain some substantial challenges. These challenges have arisen from the sheer pace and geographical concentration of wind development in the region. Whereas the Council's 5th Power Plan called for the development of 6,000 MW of wind in the next 20 years (with an implicit assumption that approximately half of this development would occur on the BPA system), BPA may see as much as 6,000 MW of wind interconnected to the BPA system alone as early as 2013. Much of the demand for this wind energy is driven by non-Federal utilities, with an increasing amount of wind development responding to the needs of state renewable portfolio standards.

As utilities across the country continue their search for renewable resources outside of their service territories, the challenges associated with large-scale exports of VERs are raising complex policy, planning, and cost allocation issues. The topic of VER exports is becoming increasingly important because most of the country's best potential renewable energy resources are located in regions that are remote from load centers. While the Pacific Northwest is taking meaningful and deliberative steps to increase coordination between the region's multiple balancing authorities and developing intra-hour transmission scheduling business practices, there are important policy and tariff issues that present significant barriers to the region's evolution towards more efficient mechanisms for wide-area optimization. These issues—in particular those associated with load service responsibility, Schedule 9 of the *pro forma* tariff, and the development of standardized methodologies for quantifying balancing reserve capacity requirements—are discussed further in Part III and the subsections below.

A. <u>The Value and Importance of High Quality VER Forecasting, Accurate VER Scheduling, and Refined and Innovative Operational Tools</u>

One of the most important drivers of efficient balancing reserve capacity utilization and reduced costs is forecasting accuracy. With a perfect hourly wind forecast, wind energy could essentially be wheeled across the exporting system with only the balancing reserve capacity for the physical movement of VERs in the regulating (*i.e.*, seconds) and following (*i.e.*, minutes) timeframes. However, because wind forecasts are imperfect, some additional amount of balancing reserves capacity to capture imbalance energy exposure will need to be carried in the overall system.

Improved forecasting accuracy can dramatically reduce the amount of balancing reserve capacity required to firm up VER schedules. BPA's last rate case valued improved wind forecasting at about $60 million per year for the rate case average forecast of 3200 MWs of installed wind capacity. Forecasting large wind ramps in particular is very valuable, as the big up and down ramps typically consume the largest quantities of balancing reserve capacity. It is important to recognize that good utility practices require that all generators, including VERs, schedule as accurately as possible using the best technology available. Leaning on the balancing authority or being overly dependent on a balancing capacity market instead of investing in readily available and cost-effective forecasting tools is unacceptable and likely to lead to higher integration costs, which are typically passed on to consumers. Although the industry has already made significant progress in improving forecasts, more development is needed in areas of infrastructure and data processing.

The support and development of high quality wind forecasting and situational awareness tools for dispatchers requires incentivizing the best possible forecasting and aligning the interests of wind generators with the needs of system operators. BPA exempted wind generators from the most expensive penalty band of the generation imbalance rate in 2002. Experience with this exemption, however, has taught BPA that providing generation imbalance service to a large and variable wind fleet requires significant amounts of capacity as well as, safeguard mechanisms to minimize persistent schedule deviations. This is particularly important on an interconnected hydro system when the accumulation of significant station control errors and associated generation imbalances can conflict with non-power operating constraints, such as meeting Endangered Species Act requirements (*e.g.*, required flows to support fish migration and spawning).

B. The Operating Dynamics of Wind Energy and the Specific Challenges of Exporting Wind Between Balancing Authorities

The primary role of wind generation in a utility portfolio is to displace fossil fuel consumption along with its associated air quality and greenhouse gas emissions, and reduce exposure to volatile fossil fuel prices. Because of its dependence on the natural variability of the earth's atmosphere, wind power is primarily an *energy* resource, rather than a *capacity* resource. When it gets very hot or very cold (*i.e.*, periods of peak utility loads) across the footprint of BPA's balancing authority area, BPA typically sees little to no wind generation. As a result, regional load serving entities must ensure that they have sufficient peaking capacity to meet their load obligations when the wind is not blowing.

Whereas utilities have had to manage the natural variability and uncertainty of loads for many years, most traditional generating resources have been dispatchable, especially during the time horizon of within-hour operations. With the entry of wind generation and other VERs, utilities are adding generating resources that are no longer dispatchable in the traditional sense and—at sufficient penetration levels—increase the overall uncertainty and variability of system operations. This increased variability and uncertainty increases the demand for system flexibility—the system's dispatchable generating resources (and loads) must now be prepared to move both to a greater degree and more frequently outside of the traditional load ramping periods to accommodate physical swings in wind output and wind forecast errors. These issues become significantly more complex in the case of exports between balancing authorities. To better illustrate this point, consider the following two cases.

Case 1: A load serving entity with its own balancing authority buys wind energy located inside its balancing authority for its own load service.

The load serving entity must have sufficient base load generation, peaking capacity, and system flexibility to follow load across all relevant time horizons. With the addition of wind to the load serving entity's resource portfolio, the load serving entity will have an incentive to forecast wind output with maximum accuracy. Based on its forecast, the load serving entity will ensure that generating capacity is available to balance the projected wind variability. Since wind forecasts are not perfect, however, the wind resource will add more operational uncertainty to the load serving entity's system and will place greater demands on the load serving entity's dispatchable generating resources.

As long as the load serving entity's dispatchable generating resources can provide sufficient flexibility and balancing reserve capacity to manage the incremental variability and uncertainty created by the wind, the system can reliably manage its aggregate system obligations. However, if the additional ramping requirements created by the wind resource exceed the flexibility of the load serving entity's system, the load serving entity may need to procure additional balancing resources.

There is some overlap between the needs for system flexibility and peaking capacity—for example, natural gas-fired power plants are often a source of both system flexibility and peaking capacity. But the need for flexibility is different than the need for peaking capacity and the distinctions in the various uses of generating capacity may not be captured in traditional utility planning for peak generation. Wind in this case may increase the demand for *flexibility* on the load serving entity's system, but the wind is not a net consumer of the load serving entity's *peaking capacity*.

Case 2: The load serving entity above purchases wind energy for load service, but the wind generator is located in an adjacent balancing authority.

Whereas in Case 1, there is *one* entity responsible for meeting the peaking capacity requirements of load and the flexibility needs of the VER, in Case 2, both the load serving entity (in this example, the importing or sink balancing authority) and the balancing authority in which the VER is physically located (the exporting or source balancing authority) have capacity obligations. Because the wind generator will not produce any energy in many hours, the load serving entity still has to have access to capacity resources to keep the lights on when the wind is not blowing. However, in this case the load serving entity's peaking capacity and balancing resources are not available to the source balancing authority, which must manage the variability and uncertainty of the VER during the period between interchange schedule adjustments, which traditionally occur each hour. As a result, the source balancing authority must also provide balancing reserve capacity to ensure that the amount of scheduled wind energy is delivered to the sink balancing authority. This leads to potential gaps or duplication of capacity obligations. Since the load serving entity is unlikely to have enough information prior to the scheduling period to make secondary sales of machine capacity that would be enabled by the scheduled firm wind generation, this translates into additional peak capacity and system flexibility requirements for the overall electric system.

Separating the obligation also creates challenges under minimum generation or restricted energy content conditions. The load serving entity no longer is responsible for managing the complete portfolio of resources and is largely isolated from the consequences of the within-hour behavior of its imported resource. Instead of the load serving entity rationally adjusting VER output when system conditions warrant, the VER operates as "must run" generation within the source balancing authority, not because of physical or system requirements, but because it is not being operated with the needs of the source balancing authority in mind. BPA has taken a number of steps to begin to address this issue by aligning VER operation with the needs BPA's system. The most prominent of these is DSO 216.[3]

C. Options for Solving the Problems Imposed by Exporting VERs Between Balancing Authorities

In addition to the potential for duplication of capacity obligations, BPA is currently looking to address another issue associated with VER exports, which arises due to the curtailment of transmission schedules under BPA's DSO 216. In the Pacific Northwest, when BPA curtails wind schedules during times when wind is generating significantly less than the scheduled amount and BPA is close to running out of balancing reserve capacity to supply the power the wind generators are not producing, the sink balancing authority will not receive the total scheduled amount of energy and must rely on other resources to make up the difference. These occurrences are fairly rare, but raise a set of issues that need to be addressed in the context of scheduling protocols, contingency reserves, and load service responsibility.

Development of intra-hour scheduling in the Northwest will likely help provide some alternative sources of balancing reserve capacity and energy during those times when BPA's or other balancing authorities' total available or contractually obligated balancing reserve capacity

[3] For description of DSO 216 see Part I, Section C, pp. 12-15.

has been exhausted. With sufficient intra-hour market visibility and liquidity, a load serving entity exposed to a DSO 216 type of curtailment will have the option of relying on its own resources or purchasing balancing reserve capacity and energy from a third-party seller for the duration of the scheduling period.

Because the intra-hour market in the Pacific Northwest is still in its infancy, the dialogue around the impacts of DSO 216 curtailments has mostly concerned whether such events should qualify as contingency events and allow for the deployment of contingency reserves. There is logic to this thinking, as it is inefficient for balancing authorities that are exporting wind to carry balancing reserves for the full range of variability of a large wind fleet. As a result, deploying contingency reserves for so-called "tail events" (*i.e.*, statistically infrequent events) may make sense. BPA notes, however, that the behavior of wind plants under all circumstances may not resemble traditional contingency events. Over time, it may be more appropriate to treat *all* of the reserve requirements for wind projects as balancing reserve capacity, rather than creating a set of qualifying events for contingency reserves. This would liberate wind projects from having to purchase contingency reserves and would create additional incentives for a more robust intra-hour market for balancing energy. BPA will continue to engage this topic with regional stakeholders through the Northwest Power Pool and other forums.

In Order 890, the Commission adopted generator imbalance service as a new ancillary service. The Commission required transmission providers to offer generator imbalance service to all generation in the transmission provider's system to the extent it is physically feasible from the transmission provider's resources or from resources available to it. Based on the language in the *pro forma* Schedule 9, it is possible that some may interpret the transmission provider's role to be a default supplier with an unlimited responsibility to supply balancing reserve capacity.

From BPA's perspective, interpreting the Commission's *pro forma* Schedule 9 to mean that the source balancing authority has an unlimited responsibility for carrying balancing reserve capacity for exports would be at odds with the basic principle of load service responsibility. As noted above, the Schedule 9 approach fosters economic inefficiency because the load serving entity in the sink balancing authority is already planning for its peak capacity needs, and placing an open-ended capacity requirement on the source balancing authority is duplicative from the perspective of generation capacity. In fact, based on BPA's experience with the issues associated with exports, BPA is convinced that the principle of load service responsibility should apply to more than just contingency reserves. *BPA believes that the VER owner and the entity that is using the VER for its own load service should have the fundamental planning, operational, and financial responsibility for ensuring that there is sufficient capacity available to manage the full range of variability of the VER—including regulation, load following, generator imbalance, and extreme tail events (big up and down ramps).* As discussed further below, such responsibilities could be met by requiring the VER owner/operator/purchaser to develop and submit an explicit balancing plan for its resource.[4]

Such an approach does not relieve exporting balancing authorities of its responsibilities. In addition to their other critical responsibilities associated with ensuring system reliability and operational functionality, exporting balancing authorities should strive to provide options for wind exporters and purchasers to procure balancing reserve capacity from alternative providers and mechanisms, such as self-supply, intra-hour scheduling, and dynamic transfer, without risking reliability and where value equals or exceeds the cost of providing the services.

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[4] Recognizing that many load serving entities that purchase VER generation are not balancing authorities, BPA recommends that these non-balancing authority load serving entities must coordinate with the VER developer as well as the source and sink balancing authorities to meet the capacity needs of the VER.

If, however, after considering other options, the VER submits a balancing plan indicating that it still prefers to procure some or all of its balancing reserve capacity from the source balancing authority, the source balancing authority can enter into a commercial transaction for such balancing reserve capacity with full cost recovery and risk protections for its preference or native load customers. The obligations of the source (exporting) balancing authority should be limited to the quantity of capacity for which it has contracted with the VER. If the VER's chosen portfolio of balancing reserve capacity (including purchases from the source balancing authority) is insufficient to manage the balancing needs of the VER, it is the VER operator or buyer and the sink balancing authority that should be accountable for making up any balancing shortfalls. This distinction between being a default supplier as opposed to a fully compensated party to a clearly defined and delimited commercial transaction is essential to the sustainable growth of VERs in exporting regions.

In the following sub-sections, BPA further elaborates on options for providing balancing services as well as the specific mechanisms by which exporting balancing authorities can clearly define and delimit their balancing reserve obligations.

1. Dynamic Transfer

The most direct way of changing the balancing reserve capacity responsibility for VERs from source to sink balancing authorities is through dynamic transfer.[5] Dynamic transfer presents one potential solution to the cost and efficiency issues associated with exports. In contrast to the scenario in which the within-hour balancing obligation resides with the source, shifting the balancing responsibility to the sink balancing authority that is using the VER for load service would minimize capacity and flexibility duplication. It would also create stronger

[5] Dynamic transfer is the means by which the electrical output of a generating resource is balanced in real-time by an entity other than the balancing authority in which the resource resides. Included in the definition of dynamic transfer are both dynamic schedules and pseudo-ties.

incentives for cost-reduction, retrofitting of existing generation for greater flexibility, and the development of more robust voluntary intra-hour markets for balance reserve capacity. With the establishment of such markets, an entity like BPA could participate by making discretionary surplus sales of hydro-system capability during those periods when it was the most cost-effective resource for a particular increment of balancing reserve capacity demand. BPA notes that at least one of California's larger investor owned utilities is exploring the use of pseudo-ties between the Northwest and California to transfer the variability of wind projects located within the BPA service territory to the California ISO's balancing market.

BPA notes that although dynamic transfer may be mutually advantageous and economically efficient in some situations, it is not a panacea. There are significant technical limitations to the expanded use of dynamic transfers, which are described more fully in Part III, Section B.1, question three responding to the Commission's specific questions. There are also infrastructure costs associated with moving regulating and following signals across long distances. Those costs need to be weighed against the savings using the peaking resources located near the load and the relative costs of new regulating and following capacity in each area. If investment and operational costs associated with increasing dynamic transfer are to be incurred, transmission providers need mechanisms to recover those costs from the entities creating the demand for the new service.

Having each balancing authority independently meeting its balancing reserve capacity needs does not take full advantage of VER diversity between balancing authorities, which includes effects of load variability between balancing authorities, and deploying the most cost-effective balancing reserve capacity resources. BPA and other Northwest balancing authorities are working together to explore the development of cost-effective mechanisms that support wide-area optimization in the provision of balancing reserve capacity. Although dynamic transfers may not be appropriate in all situations, it is BPA's belief that placing the load service responsibility for balancing reserve capacity with sink balancing authorities is a necessary *precondition* of such broader market mechanisms since it will clearly define which entities are driving the need for balancing reserve capacity, clarify cost causation and cost allocation, and increase incentives for the development of capacity markets because the same entities that are receiving the benefits of the VERs will have increased motivation to search for the least-cost solution to their balancing reserve capacity needs. From BPA's perspective, clearly defined load service responsibility and wide-area optimization go hand in hand.

2. Balancing Plans

Any good management or regulatory system creates clarity as to which entity has accountability for specific outcomes. It is BPA's view that the accountability for assuring that adequate balancing reserve capacity is available for VERs that export generation from a balancing authority should rest with the buyers and the sellers of the VER generation, not the source balancing authority. The buyers and sellers can best determine the quality of service and cost they prefer. The source balancing authority should not be a default supplier of balancing reserve capacity particularly when other options are available for obtaining balancing reserve capacity.

A first step toward establishing clear responsibility and a more diversified and clearly defined set of alternatives for balancing reserve capacity is to require VER owner/operators/buyers to develop and submit balancing plans for their VERs.[6] These balancing plans should become one of the interconnection customer requirements contained in the

[6] In the case where the VER is not sold under a long-term power purchase agreement, the VER owner should be responsible for providing a balancing reserve capacity plan to the source balancing authority.

Commission's standard Large Generator Interconnection Agreement ("LGIA") and Small Generator Interconnection agreement ("SGIA"). Through such a process, the interconnection customer would be required to determine and document for the transmission provider the interconnection customer's specific strategy for procuring balancing reserve capacity for its VER. The applicant could elect to dynamically transfer the resource off of the source balancing authority's system to the extent such capability is available between the source and sink balancing authority, self-supply all or a portion of its needs from resources within the source or sink balancing authority's service territory, or purchase all of its balancing reserve capacity directly from the source balancing authority. With this information in hand, the source balancing authority could then more effectively plan the balancing reserve capacity requirements of its system.

Consistent with the spirit of Schedule 9 of the *pro forma* tariff, the source balancing authority would quantify, post, and make available sales of balancing reserve capacity from its own resources that are net of its other statutory reliability, non-power (*e.g.*, fish and wildlife), contractual, and preference or native load obligations. The source balancing authority would provide balancing services up to this net amount of balancing reserve capacity (or, potentially, a smaller amount if the source balancing authority must reduce the amount of capacity available on a planning basis in accordance with good utility practices or, in the case of an entity like BPA, statutory obligations).

In addition, the source balancing authority should be allowed to determine an operating margin for balancing reserve capacity requirements to prevent being pushed to the edge of reliable system operations by VERs. This could be accomplished, for example, by limiting the amount of total decremental capacity available on the source balancing authority's system from its own resources to avoid minimum generation violations. This approach is analogous to the concept of a Transmission Reliability Margin and it would need to be subject to clear rules to prevent inefficiencies and abuses.

If the net demand for balancing reserve capacity for the VER resources interconnected to the source balancing authority exceeded the available capacity from existing balancing authority resources, the balancing authority would run an acquisition process for additional balancing reserve capacity and assign the incremental costs of such balancing capacity to the entities or class of entities driving the need for such capacity. The source balancing authority must recover all the costs and cover all risks associated with such an acquisition. The most likely acquisition timeframe would be across the rate period, but longer-term acquisitions could be accomplished with the requisite cost-recovery and stranded cost provisions.

Until markets develop further for these resources, it may take time for the source balancing authority to acquire the capacity resource. Since reliable operations depend on having adequate amounts of balancing reserve capacity, there may be higher incidences of reliability related VER generation reductions and schedule curtailment events. This approach would operate in much the same fashion as requests for additional transmission capacity that must wait for facilities to be built to accommodate the additional capacity needs or rely on conditional firm service and other non-firm products until the new facilities are completed. Similarly, there should be a commitment period, so that a source balancing authority that acquires balancing reserve capacity resources to meet a request does not face stranded cost risks if the requestor chooses another alternative to meet its balancing requirements.

The source balancing authority would need to maintain a mechanism like DSO 216 to limit its balancing reserve capacity responsibilities to its firm contractual commitments to provide such services and maintain reliability. In this approach, it is ultimately the planning, operational, and financial responsibility of the user of the VER to ensure the availability of sufficient balancing reserve capacity, but the balancing authorities play an important commercial facilitation and cost allocation role for the delivery of such capacity. This approach is compatible with dynamically transferring VERs to sink balancing authorities, but also leaves open the potential for economically efficient transactions that allow sharing of balancing reserve capacity requirements and ensures that source balancing authorities play an active role in supporting VER development without assuming inappropriate financial obligations. For example, the source balancing authority could sell balancing reserve capacity to manage the regulation and following components, and the sink balancing authority could maintain reserves to manage the imbalance and contingency reserve components of the VER. This type of arrangement would not require dynamic transfer capability, but would have the benefit of reducing the system flexibility and capacity obligations of the source balancing authority, and tap into the peak capacity already accounted for in the sink balancing authority's capacity obligations to meet its load.

Although BPA intends to support the development of operational solutions that will mitigate the need and downstream impacts of curtailments under DSO 216, BPA believes that a mechanism such as DSO 216 is an essential part of BPA's operational toolbox for the foreseeable future. Such operational and reliability protocols may require re-examination of product definitions and tagging protocols for VERs. BPA's aim is to maintain the value of renewable energy resources in the marketplace while promoting a more rational and efficient distribution of the responsibility for planning and paying for balancing reserve capacity.

Under the balancing plan framework, the source balancing authority provides the VER developer or load serving entity with options for how to meet the balancing reserve capacity needs of its resource. As a result, it may be appropriate for the source balancing authority to be given the discretion to charge incremental or market-based rates for the use of its balancing reserve capacity. This type of pricing discretion is likely necessary if the Northwest is to see the development of new markets for balancing reserve capacity and to prevent the hyper-concentration of balancing obligations on source balancing authorities that are otherwise required to sell at embedded cost rates.

D. Impacts on Wholesale Energy Markets and Non-Power Constraints

The discussion of how to successfully integrate VERs cannot ignore the impact of VERs on the wholesale energy market. BPA has observed that production incentives, which are important mechanisms for achieving public policy objectives, have the unintended consequence of incentivizing VERs to attempt to maximize their generation under all conditions, even during periods when the incremental value of their generation to the system is extremely low or may conflict with non-power constraints, such as endangered species protection. Such production incentives also motivate VERs to generate above and beyond their scheduled output.

There also appears to be a correlation between the significant increase in VERs and the occurrence of negative market prices. Such occurrences appear to be a further reflection of the incentives mentioned above. When market prices are extremely low or negative, traditional generators respond to these price signals and will shut down or reduce generation. The operating incentives provided to VERs dampen these price signals and they will continue to operate up until the point at which their costs of finding a sink for their energy exceed their incremental revenues from tax and renewable energy credits.

These problems are worse during light load hours, but there is also an impact during heavy load hours. For example, excessive over generation by the wind fleet during constrained water conditions can push BPA's hydro system to the brink of violating Endangered Species Act and Clean Water Act obligations. These conditions are creating a trade-off between meeting statutory and environmental obligations and, where there are no other options, potentially having to pay VERs the value of their production tax credits and renewable energy credits to not operate. Ultimately, solutions to the dramatic growth of VERs need to address these impacts on the energy market and ensure proper controls on behavior that may negatively impact energy markets or contribute to potential violations of Federal and state environmental laws.

E. Renewable Energy Credits

The use of renewable energy credits to meet renewable portfolio standards can create greater economic efficiency in the market place. However, unbundling of renewable energy credits, which allows the credits and attributes to be sold separately from the energy produced by VERs tends to make most of the issues described above worse. The separation of the credits and attributes from the physical power makes it possible to export the credits and attributes while leaving the "brown power" and its variability in the source balancing authority or region. This exacerbates the reliability challenges and impacts of negative pricing associated with VERs. All these other issues must be addressed in order for renewable energy credits and attributes to be disposed of separately in the market place. BPA is actively engaged with regional stakeholders to develop durable solutions to these issues.

F. Policy Summary

The development of significant amounts of VERs for export has had a significant impact on the operation of the electrical system and challenged the ability of source balancing authorities to meet their many reliability and operational obligations. Unless these issues are resolved, source balancing authorities for exported wind will experience reliability or cost consequences that will almost certainly have a negative impact on future resource siting and development in host regions.

A multifaceted solution is needed to ensure a rational operating and cost recovery environment for VERs and affected balancing authorities. BPA and other Pacific Northwest balancing authorities—both Commission jurisdictional and non-jurisdictional—met recently to discuss many of these issues and there is significant agreement around accelerating the efforts to implement intra-hour scheduling and to better quantify and expand dynamic transfer capability. There was some discussion of creating an independent market coordinator to facilitate an intra-hour balancing reserve market, although several entities have outstanding concerns regarding how this would work in terms of statutory requirements and jurisdictional status. Balancing authority consolidation feasibility studies are currently underway and BPA is committed to analyzing these studies to evaluate the cost and benefit associated with pursuing consolidation further. In exploring such options, BPA remains concerned about Commission jurisdiction over a consolidated entity. The Commission should encourage these ongoing efforts for regional solutions, but not require consolidation of balancing authorities to address the issues raised by the rapid and large-scale increase in VERs.

BPA intends to continue to work on strategies that will reduce the cost and total demand for balancing reserve capacity, address the inefficiencies and inequities of multiple balancing authorities in a fashion that is consistent with regional values, and support continued technical and policy innovation on the topic. These major policy positions are reflected in BPA's answers to the specific questions of the Notice addressed below.

III. RESPONSES TO QUESTIONS

A. <u>Data and Forecasting</u>

BPA supports the Commission's efforts to find solutions to the issues associated with forecast accuracy and situational awareness tools for system operators. By improving data and forecasting practices, the scheduling accuracy of VERs will improve, resulting in lower costs and less need for reserve capacity to balance the output of VERs.

The industry has already made significant progress in improving forecasts; however, more development is needed in areas of infrastructure, data processing, and coordination with the National Weather Service. BPA has already initiated several efforts toward development of better data and forecasting systems. These efforts include:

- Installation and operation of meteorological data collection sites to provide data to the public.

- Development of BPA wind output forecasting capability based on use of National Weather Service data and base models, combined with additional local data and refined through statistical post-processing to improve accuracy at the local level. BPA anticipates publication of fleet-level wind energy output forecasts once BPA refines the accuracy of its forecasts.

- Discussion with National Weather Service managers on the need for a field study to determine potential sites for additional weather sensing instruments, analysis of improvements in forecast accuracy, and recommendations for collaboration on such a field study to the Department of Energy and NOAA.

These efforts will contribute to better forecasting and scheduling accuracy of VERs in BPA's balancing authority, but additional efforts will be necessary to bring about widespread improvements in data access and weather forecasting across the industry. BPA makes the following recommendations to the Commission:

- Some balancing authorities do not perform the scheduling functions for wind or other VERs within their balancing authority area and may not have access to generation forecasts, wind forecasts or real-time meteorological data that are necessary to optimize balancing reserve capacity on the overall system. The Commission should require VERs to provide generation forecasts and generation unit status and outage information to their host and sink balancing authorities, but not require balancing authorities to publically disclose confidential plant-specific generation forecasts.

- To the extent possible, the Commission should coordinate any weather forecasting improvements and investments with the National Weather Service to build on existing expertise and benefit the entire weather enterprise.

- The Commission should not mandate centralized forecasting, but encourage a combination of centralized and decentralized post-processing of National Weather Service base weather models to predict localized energy output in order to support ongoing participation by private sector forecast vendors, VER generation owner and operators, and balancing authority area forecasters.

- Local and national entities, including the Commission, should support any National Weather Service efforts to improve forecast data for the Pacific Northwest

Question 1. What are the current practices used to forecast generation from VERs? Will current practices in forecasting VERs' electricity production be adequate as the number of VERs increases? If so, why?

In general, the industry utilizes weather forecasts to predict the generation output of VERs such as wind and solar resources. The basic information for weather forecasts comes from the National Weather Service, which is responsible for compiling meteorological data and providing base weather model forecasts and making data available. BPA and most wind forecasters use an approach that combines National Weather Service models with local data, plant production curves, and statistical post-processing (*i.e.*, statistical analysis of wind actual generation output in relation to scheduled output). The end product is a forecast that is customized using statistical techniques and additional plant-specific weather and generation information to predict VER generation output.

BPA has two primary concerns about the adequacy of current practices. First, BPA is concerned that existing base weather models are not sufficiently tailored to address the geographically specific needs of VERs. Specific regional meteorological investments and studies are needed to update these models and eliminate any deficiencies. Since the entire industry ultimately relies on the same base weather models and meteorological data from the National Weather Service, if data or model shortcomings limit the National Weather Service's ability to analyze or predict correctly the meteorological environment, then these limitations will manifest themselves in the forecast accuracy of the entire industry. These base models require continued refinement and improvements. Improving the accuracy of these base National Weather Service weather models and meteorological observing systems is essential to improving VER forecasting both regionally and nationally. BPA discusses its recommendations to address this issue in its response to question two below.

Second, system operators currently have insufficient access to VER meteorological, forecasting, and unit status information. There is currently no requirement for VERs to share such information with system operators. The inability to access such information is particularly troublesome for a system operator that does not perform the scheduling functions for VERs within its balancing authority area. Without this information, the system operator must take a reactionary and defensive approach to managing VER schedule inaccuracies and the difficulties associated with operations planning and non-power constraints. BPA discusses its recommendation to address this issue in its response to question four below.

Question 2. What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (e.g., meteorological, outage, etc.), sampling frequency, and sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?

A variety of infrastructure improvements are necessary to transition from existing power generation forecasting systems to state-of-the-art forecasting systems. A state-of-the-art system would require significant investment in additional sensor systems, data storage and model improvements to use the sensor output. Such infrastructure will need to be tailored to meet the needs of specific geographic regions. For example, areas with more varied and complex terrain may require a higher density of unique sensing equipment than elsewhere to observe the current state of the atmosphere.

In addition to infrastructure improvements, BPA believes that improvements in National Weather Service base weather models are also necessary to transition to state-of-the-art forecasting systems. To that end, BPA recommends that the Commission and regional entities recommend to the National Weather Service the development of region-specific (*e.g.*, Pacific Northwest) field tests of sensors and other meteorological innovations, coordinated with the National Weather Service and targeted toward improvements in the National Weather Service forecasting data and base weather models.[7] Improving base weather models should result in increased forecasting accuracy across all similarly situated VERs since forecasters utilize the same base models.

To develop and integrate state-of-the-art forecasts, it is also critical that balancing authorities have access to VER meteorological forecasting data, VER plant generation and unit availability. Such information is necessary for the balancing authority to create more accurate physical plant models that translate wind speed to generation and to predict the amount of wind energy sinking to load (and displacing other generation) in the balancing authority area as well as projecting uncertainty in reserve deployment. The Commission should require VERs to submit this information to their balancing authority but not require public disclosure of generator-specific information to protect the confidential interests of the VER.[8]

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[7] The Department of Energy and National Oceanic and Atmospheric Administration have recently issued a Request for Information regarding participation in the deployment and evaluation of a limited domain demonstration meteorological measurement network to support increased sensing of the lower atmosphere and improved short-term (0-6 hr) forecasting for more efficient power system operations with wind (Reference DE-FOA-0000280). In response to the Request for Information, BPA indicated its support for additional National Weather Service effort targeting the Pacific Northwest.

[8] BPA discusses this issue in detail in its response to Questions 3 and 4 below. *See* Part III, Section A, Questions Three and Four, pp. 37-40.

BPA also suggests that the Commission facilitate regional coordination efforts with the National Weather Service to develop a prioritized set of regional investment alternatives, including type of data, sampling frequency and sampling location. It makes sense to concentrate the sampling location in areas where wind generation is concentrated. Specifically, BPA supports the concept of a National Weather Service field program in the Columbia Basin to bring in mobile sensor enhancements to help inform the best investment strategy.

Although the National Weather Service likely is best positioned to recommend enhancements to regional forecasting, BPA suggests that enhancements to improve weather forecasting could include:

- Sensor systems that perform vertical profile measurements, such as SODAR, LIDAR, or vertical radar profilers. Vertical profiling information is especially important to help capture unique meteorological effects in areas of complex terrain.

- Supporting Federal (National Oceanic and Atmospheric Administration and National Weather Service) computing resources to support higher-resolution numerical weather prediction models and ensemble systems in terms of faster and more accurate data assimilation, model run-time, data storage, and high-speed (real-time) dissemination systems. The higher resolution of National Weather Service models and ensembles are particularly important in regions of complex terrain.

- Ensuring availability of all wind plant meteorological data (temperature, pressure, wind, etc.) that could help with private sector analyses as well as inclusion in National Weather Service numerical weather prediction models that will benefit all forecasters.

- Data sampling frequency (surface observations) of faster than or equal to two minute intervals, where faster data would be averaged at the end of two minutes and reported at that point in time. The averaging or filtering period of data used in National Weather Service model initialization should be commensurate with the grid spacing or resolution of the model to ensure that spurious transients are not included in model initialization.

- Complex terrain will require more sensors and optimal siting to capture short-range variability and turbulent fluctuations within the planetary boundary layer, which is the atmospheric layer closest to the earth (approximately 1 km during the day) and the layer that surrounds wind turbines.

Finally, BPA acknowledges the uncertainty as to whether the benefits from infrastructure investments will outweigh costs. The relationships between additional sensors and improved forecasts, for example, are not well established. When considering state-of-the-art forecasting systems, the Commission should also consider alternatives to weather forecasting techniques, such as persistence scheduling,[9] which may improve scheduling accuracy at lower costs.

Question 3. What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?

To more effectively manage ramping events and other variations in VER output, BPA is taking efforts to accurately forecast VER generation output and is developing tools such as information displays and monitoring algorithms to give BPA's hydro operators and transmission system dispatchers advanced warnings of significant ramp events. These efforts also include the development of both plant-specific and wind fleet level forecasts.

In addition, BPA is considering acquiring vendor forecasting services and is encouraging wind generators to provide the forecasts they develop independently to BPA. BPA needs both weather and generation forecasts to create more accurate physical plant models that translate wind speed to generation, to predict the amount of wind energy sinking to load (and displacing other generation) in the balancing authority area, and to project uncertainty in reserve deployment to allow better optimization of hydro operations. The Commission should require VERs to disclose to their balancing authorities a minimum data set[10] that would enable the system operator to know the real-time capability of each VER facility as well as the local meteorological data from each VER facility for the system operator to forecast the near-term

[9] Persistence scheduling refers to consistently scheduling transmission demand that reflects the output of the generator at a specific time in the past. For example, the demand in a schedule submitted based on two-hour persistence would reflect the output of the generator two hours before the scheduling hour.

[10] BPA discusses this data set in more detail in response to Question 4 below. *See* Part III, Section A, Question Four, pp. 39-40.

conditions. BPA is working with the wind generators within its balancing authority area to obtain such information.

Some VERs may be reluctant to disclose such information for confidentiality and business-sensitive reasons. BPA believes, however, that balancing authorities can take steps to protect the business sensitive nature of VER forecasting information. BPA suggests in question four of this section that the Commission could develop additional confidentiality protocols if the Commission determines that additional information management requirements are necessary. If balancing authorities are given access to that information, comparing the VER operator's independent forecasts with those of the balancing authority would provide insight into how the dispatchable generation that provides balancing services to VERs will be responding for the remainder of the hour. For BPA, it will also give the real-time hydro scheduler an accurate estimate of how much energy purchases or sales are needed for the next hour and how the hydro system will need to be set up (*e.g.*, project generation setpoints) for the next hour. This would enable system operators to improve efficiency in managing VER imbalances and optimize the use of balancing reserve capacity across their systems with commensurate lower costs to consumers.

For weather forecast accuracy, BPA, VER owners and operators, and other weather or generation forecasters generally perform an evaluation of accuracy on a continuing basis. To enhance forecasting tools and processes, it is necessary to ensure at a minimum that validation procedures include an evaluation of any reduction in forecast error, scheduling error, and balancing reserve capacity requirements derived from better weather forecasting. This information will help to quantify the benefits derived from any investments in meteorological infrastructure and forecasting tools.

Question 4. What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the pro forma OATT would be necessary to accommodate these requirements?

BPA has developed a general list of data that the Commission should require wind generators to give to their source balancing authority to improve system visibility and reliability. While BPA has not yet developed requirements for solar generation, BPA anticipates needing information as to generator nameplate, status, output, and any available meteorological readings for solar and other VERs.

BPA believes the general list of data below to be consistent with requirements established in other balancing authorities. BPA's data needs include:

- **Plant Meta-Data** (Static or provided once as plant information and updated every time it changes, *i.e.*, a new unit is added, etc.): Turbine number, string number, model type, and generation capacity.

- **Real-time Data** (Dynamic, reported at intervals)

    - <u>Meteorological</u> – Any information from met towers as well as representative nacelle-mounted instruments (wind speed, wind direction, temperature, pressure, and humidity where available). Report data in 1-minute averages at the end of each 1-minute interval from each wind plant.

    - <u>Turbine String Generation</u> – Current output by string, *e.g.*, "String #3 is currently producing 10MW." Report data in 1-minute averages at the end of each 1-minute interval from each wind plant.

    - <u>Turbine Availability</u> – Unit status for each turbine with 1-minute reporting granularity. In addition, outage schedules will be updated whenever new information becomes available and reported as far into the future as is known (*e.g.*, "Turbine #45 will be down between 8am on 5/20/10 and 9pm on 5/23/10").

BPA has learned that the size of individual VER generators is less important than the total aggregate capacity of that type of resource on the system. When the output of VERs is small, it can be treated as part of load variability. But once the total capacity begins to have system impacts, data collection becomes necessary for reliable operations.

BPA suggests that the Commission specifically allow balancing authorities to require all VERs to transmit unit location and capacity (“static data”) and status and output (“real-time data”) to the balancing authority for each generating unit. Since balancing authorities need such information to predict the amount of VER energy sinking to load (and displacing other generation) in the balancing authority area as well as to determine and optimize reserve requirements, the Commission could clarify its data sharing requirements under the *pro forma* LGIA and SGIA to require disclosure of such information to the transmission provider for reliability and operational reasons. BPA notes that utilizing the LGIA and SGIA to obtain such information may be appropriate since those agreements already contain protocols to protect confidentiality. Alternatively, the Commission could require disclosure of unit location and capacity (static data) and status and output (real-time data) pursuant to mandatory reliability requirements developed by NERC.

Since some data requirements may be perceived as burdensome for very small VERs, it may be possible for balancing authorities to obtain small VER real-time data on an aggregate basis, such as in the context of aggregating monitoring programs like Smart Grid. Output of such small VERs would be measured by a metering process in real time rather than through an Inter-Control Center Communication Protocol. Regardless of size, however, the balancing authority should be informed of the existence of static data for all VERs.

Question 5. 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?

BPA supports public access to all meteorological data. Ideally, meteorological data from VERs should be made publicly available, including wind readings at wind generation plants. However, BPA makes a clear distinction between meteorological data and generator-specific information such as generator status, generation output and generation forecasts. As noted above, the Commission should require both meteorological and generator-specific information to be provided to the balancing authorities, but not require generator-specific data to be made public.[11]

BPA also believes that the best point for centralized collection of metrological data is the National Weather Service. The National Weather Service has a massive existing system for collecting and distributing weather data, and any entity that is using weather data is likely already interconnected to the National Weather Service system. It is also likely to be easier for all parties to link to a single centralized source. The National Weather Service could incorporate the data provided to it from VERs in their base analyses, models, and ensembles to provide benefits for all users.

The Commission should not require public utilities to maintain a meteorological reporting system. Even if balancing authorities were required to collect and ensure public access to specific weather data in their balancing authorities, such data would still need to be submitted

[11] *See* Part III, Section A, Question Three, pp. 37-38.

to the National Weather Service. Instead of a centralized location for such information, however, entities seeking to use such data in their own post-process analyses of the National Weather Service base models would have to go to each balancing authority to obtain the data. This result would be inefficient. The Commission should encourage the use of the National Weather Service as the centralized repository, rather than requiring public utilities or balancing authorities to take on this responsibility.

Question 6. Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting? For example, should transmission providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?

The forecasting and scheduling of VER generation in the Pacific Northwest is currently completely decentralized. The National Weather Service base forecasts and ensemble forecasts provide a starting point for all local weather forecasting. BPA, wind generators, and wind forecast vendors develop statistical post-processing of the National Weather Service models to refine these local forecasts. This approach has merit because it enables system operators and VERs to independently select forecasting approaches that best serve their needs. BPA, for example, is currently developing both fleet-level and plant-level generation output forecasts for its own uses and intends to make the fleet-level forecasts publicly available.[12] BPA expects its forecasting tools to produce forecasts that VERs within its balancing authority area can utilize.

In contrast, centralized forecasting—where the balancing authority and system operators manage meteorological and VER energy production forecasting for VERs—would require transmission providers to perform independent forecasting for VERs. Centralized forecasting may be problematic for transmission providers that do not perform the scheduling functions for VERs. Nevertheless, it may be worth further consideration on a case by case basis, especially if

[12] Plant-level forecasts, however, are not publicized because they are based on proprietary information.

it resolves discrepancies between the objective functions of system operators and VER operators that result in increased operating costs and potential conflicts with other operational requirements.

The Commission should not require centralized forecasting, but instead encourage regional coordination and decision-making on this issue. As BPA continues to refine its forecasting tools, BPA will continue to discuss with regional stakeholders the optimal approach to wind forecasting as well as the costs and benefits of centralized forecasting.

Finally, the Commission should recognize that there are multiple models for balancing reserve capacity management and reliability commitment processes and that the timeframes for balancing reserve capacity forecasts may differ. For example, the reliability commitment process for BPA is conducted on a rate case (two-year) cycle and is somewhat independent of the need for accurate short-term energy output forecasts. Other system operators may forecast balancing reserve requirements on a shorter timeframe. Thus, with regard to reliability commitment processes and prediction of balancing reserve capacity requirements, Commission policy should preserve the flexibility of system operators to determine the appropriate timeframe for balancing reserve capacity forecasts.

Question 7. 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?

BPA forecasts balancing reserve requirements on a two-year basis during BPA's rate case process, for the combination of loads and wind. BPA has learned that each VER generally contributes to the total balancing reserve capacity requirement, whether or not it is behind the meter. If the VER is behind the meter, the reserve requirement attributed to that VER is considered as part of reserves for load variability rather than generation output variability.

Having knowledge in real time of the operational status and forecasted output of behind-the-meter VERs could help improve real-time management of reserves if the behind-the-meter VERs are having a significant impact on load variability. As the total output of small-scale VERs grows, it will become more important to impose the same data requirements on these resources as on other VERs. As discussed above under question four, BPA has developed a general list of data that the Commission should require wind generators to provide to their balancing authorities to improve system visibility and reliability. Included in that list is the operational status and forecasted output data of distributed or behind the meter data of VERs.

B. Scheduling Flexibility and Scheduling Incentives

B.1. Scheduling Flexibility

The Commission questions whether greater scheduling flexibility could benefit systems and facilitate the efficient and reliable use of resources. BPA currently is conducting a pilot program to test whether intra-hour scheduling has those benefits and to assess the impacts of intra-hour scheduling on its transmission and hydro systems. Because the pilot has been in effect for only a few months, it is too soon to draw any conclusions; however, BPA expects that the combined effect of intra-hour schedules and other initiatives over time should help promote more efficient use of resources to balance VER output.

BPA summarizes its positions on the primary issues in this section as follows:

- The Commission should not eliminate the hourly scheduling platform, which works well for dispatchable resources.

- Mandating intra-hour scheduling or standardizing national practices is premature. Development of intra-hour practices should be left to coordination among balancing authorities within the interconnection.

- If the Commission adopts national standards, it should establish one intra-hour scheduling interval at 30 minutes after the hour. This will help capture the benefits of resource diversity across an interconnection and manage exposure to imbalances of both source and sink balancing authorities, while limiting the potential for adverse impacts on reliability or systems and processes.

- Scheduling intervals shorter than 30 minutes represent dynamic transfer more than intra-hour energy scheduling. Dynamic transfer in general may be an important component to the efficient integration of VERs, but it presents challenges of its own and should not be considered the sole solution to VER-related challenges.

- The 5- and 10-minute markets in RTOs and ISOs should not be confused with intra-hour scheduling. The RTO/ISO markets may help to efficiently dispatch resources on a 5- or 10-minute basis but they do not utilize intra-hour scheduling.

Question 1. Would shorter scheduling intervals allow System Operators to more efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?

In BPA's experience, scheduling inaccuracy is the primary reason for increases in balancing reserve needs. With an hourly scheduling window and a requirement to finalize generation schedules by half past the hour for the next hour, it is difficult for VERs to match actual output to schedules submitted before the hour. Although Northwest utilities do not have much experience with shorter scheduling intervals in the context of VERS, shorter scheduling intervals should help VERs to more accurately match schedules to actual output. For a balancing authority that exports significant amounts of VER generation, more accurate schedules should, theoretically, allow it to reduce the amount of balancing reserve capacity carried for the VERs because it should result in an overall smaller error. Although the sink balancing authority may have to carry an increased amount of balancing reserve capacity due to the intra-hour schedule changes, the total balancing reserve capacity carried by the source and sink balancing authorities should decline because of more accurate schedules and diversity of resources, load, and other conditions across the interconnection.

A shorter scheduling interval will help reduce overall reserve requirements for VER ramps only if a majority of VERs and balancing authorities participate in intra-hour scheduling.

If few balancing authorities allow intra-hour schedule changes or few VERs actually submit such schedules, the benefits will be minimal because there will be insufficient participants to make intra-hour scheduling effective. Policies that promote the development of intra-hour scheduling opportunities and regional collaboration on intra-hour scheduling will help achieve the benefits of shorter scheduling intervals. BPA and other Pacific Northwest transmission providers have already begun to develop intra-hour scheduling policies and practices for the region, and BPA expects those efforts to accelerate in the near future. BPA is concerned that a move toward adoption of standardized practices by the Commission could stifle the progress of the Northwest transmission providers and realization of the benefits of intra-hour scheduling.

Although BPA supports use of a shorter scheduling interval, the benefits of allowing VERs to schedule on a shorter interval should not provide a basis to eliminate the hourly scheduling platform, which has proven workable and efficient for dispatchable resources and system load. Mandating scheduling on a shorter time frame for all resources and loads would increase the workload of all system operators and schedulers, which will likely reduce efficiency and increase the possibility of errors. For BPA, mandating intra-hour scheduling for all resources would also conflict with the terms and conditions of several long-term power sales contracts and would be unworkable.

Allowing too many or increasingly shorter scheduling intervals may have a “law of diminishing returns” effect. Changes once within the hour may give the desired effect of more efficiently managing the ramps, but smaller and smaller increments of intra-hour changes (*i.e.*, less than 30 minutes) may result in unintended consequences, risks and costs. One intra-hour schedule change at 30 minutes past the hour for schedules submitted by VER generators and their counterparties would be beneficial in the management of VERs. In contrast, schedule changes on timelines less than 30 minutes would shift scheduling flexibility more toward dynamic transfer arrangements, which has its own limitations as discussed below.

The Commission asks how much relief intra-hour scheduling would give to regulating reserve capacity, which BPA defines as the moment-to-moment balancing reserve requirement typically associated with a 4-second AGC signal. BPA believes that the Commission's inquiry should extend beyond regulating reserve capacity to the total in-hour balancing capacity requirement of VERs. In developing its balancing reserve capacity service, BPA determined that the reserve capacity needs of VERs consist of three primary components: regulation reserve (moment to moment balancing), following reserve (moment to 10 minute variation balancing), and imbalance reserve (balancing the difference between schedule and actual for the hour).[13] The distinction between regulating reserves and both following and imbalance reserves is important because regulating reserves must be provided by units that are spinning, while following and imbalance reserves do not necessarily require units to be spinning in order to supply incremental reserves. In BPA's experience, VERs require relatively little regulating reserve, but they require greater amounts of following reserve and large amounts of imbalance reserve capacity. For all the reasons explained above, BPA believes that intra-hour scheduling does have the potential to lower the overall amount of imbalance reserve held for VERs.

Question 2. What are the benefits and costs of allowing resources and transactions to schedule on an intra-hour basis, and what tariff and/or technical barriers exist to implementing intra-hour scheduling? Are there best practices that could be implemented to facilitate greater intra-hour scheduling?

Despite the benefits of intra-hour scheduling discussed above in question B.1, there could be significant costs and technical challenges associated with intra-hour scheduling, especially if it is mandated for all transactions or if schedules are required to be submitted in intervals shorter

[13] *See also* Part I, Section B, pp. 11-12 (explaining regulation, following, and imbalance reserves).

than 30 minutes. BPA's response to question five in this section describes the changes to hourly scheduling systems that would be required to respond to scheduling intervals in increments less than 30 minutes.

The current lack of interconnection-wide consensus on intra-hour processes is a barrier to implementation of intra-hour scheduling. For intra-hour schedules to be effective, all balancing authorities within an interconnection would need to be using the same intra-hour timing, and automatic generation control would require modification if dispatchable generation setpoints are changed on a frequent basis. In addition, BPA would need to develop intra-hour Available Transfer Capability ("ATC") and Available Flowgate Capability methodologies to evaluate and grant requests if intra-hour reservations as well as intra-hour schedules are implemented.

From BPA's perspective, the current *pro forma* tariff generally contemplates submission of schedules before the hour, but it allows flexibility for transmission providers to accept late schedules and does not prohibit intra-hour scheduling. Although the *pro forma* tariff language should be sufficient to allow intra-hour scheduling, it may be helpful for the Commission to clarify that intra-hour scheduling is consistent with the *pro forma* tariff. In addition, although BPA does not see any immediate barriers in the *pro forma* tariff prohibiting intra-hour scheduling, a transmission provider may want to seek tariff changes depending on how it implements specific aspects of intra-hour schedules in the future.

As described previously, BPA is conducting a pilot program to assess the effectiveness and benefits of intra-hour schedules. Until BPA better understands the benefits and drawbacks of intra-hour scheduling, BPA cannot specify details about the "best practices" that would facilitate more intra-hour scheduling. Given that many other transmission providers may be in a similar position, the Commission should not eliminate the hourly scheduling platform or mandate intra-hour scheduling standards based on conclusions about best practices under these circumstances.

Question 3. Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?

BPA's intra-hour scheduling pilot program allows VERs to submit schedules at 30 minutes past the hour. BPA believes that one intra-hourly scheduling interval at 30 minutes past the hour will capture a significant share of the benefits of intra-hour scheduling for VERs and avoid many of the potential problems associated with shorter intervals. Schedule changes at the half hour may help to more efficiently manage VER ramps, but schedule changes in intervals shorter than 30 minutes may introduce unintended consequences, including risks and costs associated with voltage, special protection systems, and transmission studies. The use of intra-hour scheduling at intervals of less than 30 minutes for interchange schedules currently presents serious technical challenges because of the time required (1) for marketers to find a buyer, create a reservation, and create an E-Tag and (2) for operators to check out with adjacent balancing authorities, as well as to reset dispatchable plant setpoints and change unit commitments. At this time, BPA believes it is premature for the Commission to mandate intra-hour schedule intervals, particularly intervals less than 30 minutes. Regions of the country that manage within hour variability on a 5 or 10 minute dispatch basis have more fundamentally restructured their markets and do not actually rely on "intra-hour" scheduling. Thirty minutes is likely the limit of a bilateral intra-hour market.

BPA's response to question one in this section explains that scheduling intervals shorter than 30 minutes begin to resemble dynamic scheduling rather than intra-hour scheduling. Although hourly dynamic scheduling with more frequent dispatch intervals may provide benefits and should be considered an option for VERs, as BPA explains below, dynamic transfer in general presents its own set of challenges, and the Commission should not consider it as the one reform that could resolve the uncertainty associated with VER generation.

Expanded Use of Dynamic Transfer[14]

Dynamic transfer is the means by which the electrical output of a generating resource is balanced in real-time by an entity other than the balancing authority in which the resource resides. Throughout these comments, BPA refers to dynamic transfer as a potential tool for facilitating the integration of VERs onto the system. Dynamic transfer represents an enhanced use of the system. But because there are limits associated with the system's ability to support that use, caution must be taken in increasing dynamic transfers on the system.

Dynamic transfer capability is limited in many regions. As a result, transmission owner and transmission operator companies may need to increase the dynamic transfer capability of the transmission system. The grid and its controls were designed for system conditions where, with the exceptions of ramp periods or contingencies, the only significant variation was a result of load following. Dynamic transfers challenge this fundamental assumption and make it clear that the old control strategies, largely manual, are not sufficiently flexible to accommodate unrestricted expansion of dynamic transfer. While providing greater operational flexibility, dynamic transfer requires that adequate provisions are made for the effect of real-time variation on the transmission system. Currently no industry standard method is available to calculate dynamic transfer limits over multiple transmission paths. In 2009, BPA initiated a pilot program, in coordination with the Wind Integration Study Team,[15] to perform a dynamic transfer

[14] Dynamic transfer capability is defined as the capability of the transmission system to continuously ramp a resource(s) over a pre-determined range, such that the control of the electrical output of such resource(s) can be varied from moment to moment by an entity other than the host utility/host balancing area operator.

[15] The Wind Integration Study Team is a technical study group that represents a collaborative effort by ColumbiaGrid and Northern Tier Transmission Group. It is intended to support technical needs of sub-regional and regional initiatives to facilitate the integration of VERs into the Pacific Northwest transmission grid.

limits study. The purpose of the study was to develop a credible, quantitative methodology to assess the impacts of dynamic transfers on the BPA transmission system and to determine the dynamic transfer capability of the system. The results of the initial study have recently been posted on the wind integration page of BPA's website.[16]

Expanding the use of dynamic transfer within the BPA transmission system and across key interfaces to other balancing authorities implicates the need for system enhancements, as well as increased staffing and training needs. Overall reinforcement to the grid and its control mechanisms may be necessary. Improvements must be made on the broader system despite the fact that wind generation on BPA's system has been developed in a distinct geographic area. This is because dynamic transfers move the variability and uncertainty of wind generation to other areas of the transmission system. System improvements may include additional reactive devices, dynamic voltage control devices, and better real-time control and visibility for system operators. Significant use of dynamic transfers will require automated arming of special protection systems and voltage control.

In addition to system improvements, increased dynamic transfers require heightened operational scrutiny to protect against adverse impacts to reliable operation of the grid. In particular, care must be taken to reasonably assure that system operators have the right tools, skills, and information for real-time operations. Expanded use of dynamic transfers will likely increase the workload and skills required for performing relevant operational functions. For example, at present, BPA dispatchers have manual control of several functions such as special protection systems arming and switching. There may be a need for fundamental changes to the current mix of manual and automated controls. Moreover, rapidly changing flows are likely to

[16] http://www.transmission.bpa.gov/wind/dynamic_transfer/default.cfm

impact other Pacific Northwest systems, which will require greater coordination of procedures, voltage control, and other real-time activities by the system operators of neighboring utilities.

Transmission owner and transmission operators should be able to recover costs associated with improvements made to accommodate use of dynamic transfer, including the flexibility to recover those costs through additional charges for transmission schedules using dynamic transfer capability. To the extent that the Commission modifies its policies relating to dynamic transfer or considers incorporating new provisions into the *pro forma* tariff, such changes should accommodate both the need to recover related costs from those causing the costs to be incurred and the need to retain adequate flexibility for using dynamic transfer as a tool in integrating VERs.

Question 4. Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?

Changing the scheduling rules to accommodate intra-hour scheduling could raise a number of reliability issues. Intra-hour schedules may raise issues related to reliability standards such as NERC Standard TOP-007-WECC-1 — System Operating Limits, which prohibits allowing net scheduled interchange for power flow from exceeding the system operating limits when the transmission provider is entering a ramp for the next hour. This standard also requires transmission operators to take steps to limit the duration of the exceedance if power flow over a path exceeds system operating limits within the hour. To maintain reliability, transmission operators may need to build additional checks into scheduling systems to identify path(s) that an intra-hour schedule would affect and then determine if sufficient capacity is available. Without such checks, transmission operators may bear greater risk of exceeding a system operating limit. The more frequent the schedule changes, the more frequent the checks that would be required. As part of its intra-hour scheduling pilot program, BPA currently is examining the best means to ensure that intra-hour schedules do not create reliability issues or affect compliance with this standard.

Scheduling windows shorter than 30 minutes also could complicate the implementation of within-hour curtailments. The requirement for multiple parties to approve an e-Tag results in a time lag between creation and implementation of a tag. If a curtailment is implemented during this time lag while tags are in pending status, those tags may not be captured in the first round of curtailment. This may require the operator to issue additional rounds of curtailments to maintain flows within system operating limits. Implementing additional rounds of curtailments becomes more difficult with shorter scheduling windows.

Although BPA recommends that the Commission not mandate intra-hour scheduling or adopt national standards, system operators and schedulers should have sufficient time to analyze, evaluate, and accept intra-hour schedules in order to maintain reliability with a 30-minute scheduling window. In addition, VERs should have sufficient time to make arrangements for the intra-hour schedule.

With respect to the Commission's question regarding whether changes to the NERC reliability standards are necessary to accommodate intra-hour scheduling, any changes should be minimal. The tables in the NERC Interchange Scheduling and Coordination standards (INT-005,006, 008), which set minimum timelines for responding to interchange requests, will likely need some adjustments to provide for intra-hour schedules. For example, another column may need to be added to the timing table for intra-hour schedules submitted less than 10 minutes prior to the start of the intra-hour ramp, clarifying each party's responsibilities for responding to the intra-hour schedule. Otherwise, operators may not have sufficient time to conduct all of the same processes and checks, some of which are manual processes, to ensure accurate checkouts for each time interval.

Question 5. How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?

As part of BPA's intra-hour scheduling pilot, VERs reserve and pay for transmission for the whole hour, but intra-hour schedules are implemented 30 minutes after the hour. Although e-Tag and OASIS systems are designed to handle intra-hour scheduling, many of the displays that are based on the reservation and tagging data are in hourly granularity and may need to be enhanced. Calculating available transfer capability for intervals less than one hour will require development of systems and processes, including hardware and software to handle the data necessary for calculating the additional reservation intervals. This is true in BPA's current, complex flow-based ATC methodology as well as in the ATC methodology mandated by the NERC Modeling, Data, and Analysis standards.

In addition, more frequent scheduling intervals will result in increased incidents of resetting dispatchable plant set points, as well as changing unit commitment and special protections schemes. More frequent scheduling intervals also have an impact on NERC mandated processes such as the requirement to coordinate scheduled interchange prior to entering a ramp. Making intra-hour scheduling mandatory and increasing the frequency of such scheduling could also require significant changes in operations planning for hydro resources that are subject to non-power constraints (*e.g.*, fish and wildlife, flood control, navigation, etc.) and limitations established by Federal law. BPA relies on dispatch of the FCRPS to maintain load-resource balance, and those resources are subject to specific river operations that may vary by season and prevailing hydrologic conditions, as well as non-power constraints such as the Endangered Species Act, Clean Water Act, flood control, and navigation requirements.

Allowing VERs and the dispatchable generators providing balancing reserve capacity to balance the VERs to submit intra-hour schedules should not mean that the balancing authority is required to adjust the hourly schedule associated with its own generation. If intra-hour scheduling does require adjustments to all generation schedules on an intra-hour basis it may be impossible for BPA and some other balancing authorities to participate.

With respect to the potential for increased costs, BPA does not believe there will be significant cost to the e-Tag and OASIS systems to accommodate intra-hour scheduling. BPA also believes that for scheduling intervals of 30 minutes or greater, the cost increases are manageable. If intra-hour scheduling becomes mandatory for all transactions or if the scheduling intervals are more frequent than 30 minutes, there will be significant costs associated with intra-hour ATC, special protection schemes, non-power constraints and other systems identified above.

Question 6. If intra-hour scheduling is implemented in non-RTO/ISO regions, how would RTO/ISO scheduling practices at interties be affected? 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.

BPA has recent experience using dynamic transfers to facilitate intra-hour dispatch with the California ISO. Providing hourly scheduling with intra-hour dispatch intervals has been effective at providing generation dispatch on 5- to 10- minute intervals.

Thus, based on BPA's experience, to the extent that scheduling practices, dispatch intervals, and ramps are consistent on the interties, intra-hour scheduling will not introduce any significant complications between RTO and ISO and non-ISO or RTO regions. RTOs and ISOs will face the same challenges implementing intra-hour schedules that non-RTO or ISOs will experience.

B.2. Scheduling Incentives

The Commission is interested in the experience with the exemption of VER generators from the third tier deviation band of generator imbalance charges in terms of proper scheduling incentives. BPA first exempted wind generators from tier three penalties when it had less than 200 MW of wind generation in its balancing authority. BPA was encouraging renewable resource development, and it recognized the difficulty of accurately forecasting wind generation. The effects of imbalance with a relatively small amount of wind generation in the balancing authority were not large, but the impacts of scheduling inaccuracy on use of balancing reserve capacity and energy are large and apparent now that BPA has interconnected significant amounts of wind generation. BPA's responses in this section explain that establishing incentives for VERs to schedule accurately are appropriate. BPA suggests:

- A combination of economic price signals is needed to encourage accurate scheduling by VERs, and ensure that the scale of the price signals in relation to the value of tax credits and other non-power attributes for VERs impacts the effectiveness of the price signals.
- The Commission should support balancing authorities that require additional scheduling accuracy incentives, including charges for large and persistent schedule deviations.
- The Commission should support charges for the balancing reserve capacity used to balance VERs.

Question 1. 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?

With a significant wind fleet operating in the BPA balancing authority BPA has observed that wind producers are incentivized to generate energy even when market conditions do not indicate demand for additional energy. These observations indicate that the current generation imbalance structure may not be enough to incentivize accurate scheduling behavior in the face of the counter-incentives provided by tax credits and renewable energy credits that have important societal objectives but also directly impact marginal operating economics. BPA believes that a combination of economic price signals is necessary to encourage development of accurate wind forecasts and to use those forecasts to schedule accurately.

In 2008, BPA analyzed the historical scheduling accuracy of the wind fleet in its balancing authority and concluded that the scheduling accuracy as a whole was consistent with a two-hour persistence model. This level of scheduling accuracy contributed significantly to the amount of balancing reserve capacity that BPA had to carry in order to provide generation imbalance service. This inaccurate scheduling took place while the generator imbalances for deviation bands one and two were in effect. Although BPA cannot attribute the inefficient scheduling solely to exemption from the third-tier generator imbalance penalty, it appears to be a contributing factor. In any event, the charges under bands one and two do not appear to provide adequate incentives.

Given BPA's more recent experience, BPA now believes that the Commission should allow system operators to adopt additional incentives to reduce large and persistent scheduling inaccuracies that occur over a specific span of time, such as three or four hours. BPA established a "persistent deviation" penalty charge under its generator imbalance service in its FY 2010-11 rates. Under the persistent deviation charge, deviations of 15% of schedule and 20 MW in the same direction for four or more hours, or identifiable patterns that are not random over and under generation, trigger a penalty charge of the greater of 125% of BPA's highest incremental cost that occurs during that day or 100 mills per kilowatthour, or no credit (in the case of over-generation). BPA is still gaining experience with this penalty charge, but BPA believes that this penalty charge has helped to improve scheduling accuracy and reduce the amount of persistent scheduling deviations on the system.

Although a persistent deviation penalty may not be necessary for some systems, the issue of large deviations over time or accumulation of imbalance over time is particularly significant for hydro system operations. BPA is finding that at times, excessive energy accumulation (*i.e.*, energy stored or withdrawn from the hydro system) is causing significant issues with system operations, despite the efforts of BPA operators and energy traders to manage generation imbalances with purchase and sales of energy in the real-time and hour-ahead markets. As a result, BPA believes that additional incentives may be necessary to encourage accurate scheduling in all hours and to prevent large energy accumulations in the hydro system. Moreover, BPA's estimates for balancing reserve capacity requirements for balancing service assume that scheduling errors will be random and unbiased. BPA needs to ensure this is the case because the hydro system is operated within many other non-power constraints and statutory requirements, and unanticipated persistent scheduling deviations that result in rapid accumulations of imbalance energy constrain BPA's ability to manage these requirements. BPA is actively exploring durable solutions to these issues with regional stakeholders.

Charges for the cost of the balancing reserve capacity to provide balancing services to VERs also are necessary to satisfy cost causation principles and incentivize accurate scheduling practices. As mentioned in Part I above, BPA first established a new rate for wind balancing service to recover the costs of the capacity for within-hour wind balancing from wind generators in FY 2009, but this charge did not include charges for the cost of carrying capacity associated with the imbalance that results from deviations between VER schedules and actual generation. In BPA's initial proposal for FY 2010-11 rates, BPA proposed to revise its wind balancing service rate to include the costs of imbalance capacity and, in doing so, it quantified the substantial cost of inaccurate scheduling for customers. As a result of identifying these costs and the proposed rates to recover them, BPA witnessed noticeable improvements in wind generation scheduling accuracy almost immediately and improvements continued over the course of the rate case, which reduced demand for balancing reserve capacity. BPA believes that such scheduling accuracy improvements were strongly influenced by its balancing reserve capacity price signals. BPA considered the improvements in establishing final rates, and it resulted in a much smaller rate increase compared to BPA's initial proposal.

Question 2. 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?

BPA has evaluated several years of hourly schedules and actual wind power output and has observed a decrease in the per unit (MW of balancing reserve capacity/MW of installed wind) use of balancing reserve capacity as scheduling practices have improved. BPA believes that improvements in scheduling are mostly due to establishment of a charge for the costs of wind balancing service. As discussed in the previous response, when BPA made the amount of balancing reserve capacity it would charge largely dependent on how well wind schedules matched actual output, wind generators improved scheduling accuracy, leading BPA to set aside less reserves at a lower rate for the service.

BPA believes that VER forecasting ability will continue to improve, but VERs will need some incentive to utilize better forecasting tools and submit schedules that are consistent with forecasts. The Commission should support balancing authorities that need to develop persistent deviation thresholds and similar incentives to incentivize accurate scheduling and minimize imbalance accumulation. For primarily thermal systems, persistent deviations may be less of an issue, but where hydro resources are providing the generation imbalance, persistent deviations can cause significant operational issues in the short term and impact total reserve requirements in the longer term. BPA believes these incentives will encourage all VERs, including small and medium sized wind facilities, to keep their deviations random and small and to further reduce the overall balancing requirement and costs of providing balancing to VERs.

C. Day-Ahead Market Participation and Reliability Commitments

C.1. Day-Ahead Market Participation

In contrast to other regions in the U.S., the Pacific Northwest does not have an RTO or ISO that manages day-ahead markets. The Pacific Northwest has 19 independent balancing authorities that manage reliability in their respective areas. Robust bilateral markets exist for day-ahead and hour-ahead power sales. While many trades are made bilaterally among the merchant functions associated with different balancing authorities, marketers, and independent power producers, a large portion of the power is traded at the mid-Columbia trading hub. These trades are facilitated through energy brokers and the Intercontinental Exchange, an electronic trading platform. Trades at the mid-Columbia hub result in a complex set of source to sink deliveries of power as interchange transactions between different balancing authorities.

The power product traded at the mid-Columbia trading hub is generally WSPP Schedule C firm power. Among other things, Schedule C provides that the seller shall ensure that transactions are scheduled as firm power consistent with the most recent rules adopted by the applicable NERC regional reliability council.

The majority of transactions among the balancing authorities in the Northwest Power Pool have historically been scheduled as firm power (firm for the hour) with the interchange delivery guaranteed through each scheduling hour absent a reliability event affecting one of the balancing authorities. BPA's balancing authority currently only allows firm for the hour transactions, reflecting the historical practices of the Northwest Power Pool and the complexity of wheeling transactions managed by BPA.

As discussed in Part I, the increasing amount of VERs integrated in the BPA balancing authority required the development of DSO 216 to maintain the reliable operation of BPA's balancing authority. DSO 216 provides that BPA will curtail transmission schedules of wind generators that are performing significantly below their schedule when BPA has exhausted the balancing reserves capacity set aside to manage VERs on a planning basis.[17] DSO 216 is a reliability tool needed to ensure that the large unplanned wind ramps do not outstrip BPA's ability to adjust its hydro system to meet the variability of the wind fleet. Even though deployment of DSO 216 has been rare, the resulting transmission curtailments of schedules tagged as firm power have raised concerns in the adjacent balancing authorities.

BPA is starting a public process to discuss with stakeholders whether VER schedules should be identified as "firm contingent" under the applicable Northwest Power Pool rules or whether an alternative e-Tag for VERs should be developed. BPA believes that either tagging the VER scheduled as "firm contingent" or some other alternative developed in the region will provide the necessary transparency for reliable operations in the sink balancing authority and help prevent irrational distortions in the market value of wind energy. The sink balancing authority will then have the information necessary to plan for potential curtailments resulting from reliability protocols designed to integrate VERs on a cost-effective basis without requiring the source balancing authority to hold reserves to meet every conceivable VER operation. The anticipated change to the e-Tag designation should also provide more transparency that will improve the operation of the wholesale power market in the Pacific Northwest. BPA's ultimate

[17] The balancing reserve capacity set aside to manage VERs is established on a two-year planning basis through BPA's bi-annual rate case process.

objective is to develop operational and tagging protocols that support efficient and reliable operations while attempting to maintain the market value of VERs, and BPA's responses to the questions in this section should be viewed with that objective in mind.

Question 1. Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases? Will out-of-market commitments increase as the number of VERs increases? If so, why?

VERs participate in the day-ahead market in the Pacific Northwest. As this participation has increased some counter parties in the day-ahead market have raised transparency concerns regarding whether the VER is selling WSPP schedule C firm power and the extent that the VER is backed up by sufficient balancing reserve capacity. The majority of the VER generation in the Pacific Northwest is sold under longer-term power purchase agreements. Under these arrangements the firmness of the energy produced by the VER is generally not an issue, and responsibility for carrying balancing reserve capacity for exported VERs is discussed at length elsewhere in BPA's response. Currently in the Pacific Northwest there is a limited amount of VER generation not committed under long-term power purchase agreements, which is sold into the day-ahead and hour-ahead markets.

From BPA's perspective, VERs that have little demonstrable capacity value should only be allowed to sell WSPP Schedule C firm energy in day-ahead markets to the extent that they can support their uncertain and variable generation with other dispatchable capacity resources or products. Some parties have sold VER output as day-ahead Schedule C firm power and have sought to replace the output with energy in the hour-ahead market when the VER is not generating. If energy is not available in the hour-ahead market, the seller may not always replace the energy, leaving the load serving entity to find capacity to meet its load. In the day-ahead market the purchaser may not know whether the VER generation is being marketed as a stand-alone resource backed up by hourly market purchases or if the seller has access to dispatchable resources to firm up the VER. A majority of the transactions in the Pacific Northwest day-ahead market involve more than two parties. As a result, the end user does not have a contract with the generator, and under current market rules there is no way for the end user to know whether the VER is standing alone or if the VER has dispatchable generation backing it up. This lack of transparency also applies if the VER is subject to curtailments during the operating hour due to under performance, but there is no reason that VER generation subject to such curtailments cannot be considered firm if it is backed up by dispatchable resources. VERs that are sold into the day-ahead market without the necessary capacity resources need to be identified as something other than firm. As more VER generation is installed, Pacific Northwest market participants must address these transparency issues in order to promote full participation by VERs in the day-ahead market.

Question 2. How can new or existing market design features assure that the day-ahead market will accurately represent real-time system conditions and that day-ahead and real-time energy prices will converge under the scenario of increasing numbers of VERs?

BPA has no experience that suggests that day-ahead markets and hour-ahead markets will converge under the scenario of increasing numbers of VERs. BPA, however, is concerned that these markets will increasingly diverge as the size of the wind ramps increase. Increased VER participation in day-ahead markets will not change the operational issues experienced in real-time operations. Balancing authorities will still face the same issues with the accuracy of hour-ahead schedules and the need for balancing reserve capacity to ensure reliable operation of the balancing authority. Since wind ramps are difficult to predict on a day-ahead basis and typically manifest themselves during hourly operations, it is possible that traditional arbitrage constraints between day-ahead and real-time prices may not be as effective in a world with increasing quantities of VERs.

Question 3. Do current RTO/ISO market designs place undue barriers to participation in forward markets by VERs? Could the timing of certain RTO/ISO market design elements, such as the day-ahead market, be modified in a manner that would facilitate VERs to participate more in the day ahead market rather than primarily in the real time market? If so, how?

This question is not applicable to system operators in the Pacific Northwest.

Question 4. Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?

Any forecast of weather events, especially a forecast of the wind a day in advance, will have a significant band of uncertainty around it. As a result, BPA does not believe that day-ahead wind forecasting technology will advance sufficiently to allow wind energy to be sold as day-ahead WSPP Schedule C firm power on a stand-alone basis. It will still be necessary to supplement the wind output with other dispatchable capacity resources in order to firm up the power. BPA is aware that the current market and product design in the Pacific Northwest, with its distinction between firm and non-firm energy and the lack of a deep reserve capacity market, may exacerbate some of the challenges associated with day-ahead sales of VER output. Theoretically, in a centrally administered reserve capacity market, a better day-ahead forecast should improve unit commitment processes and determinations of required reserve capacity for within hour balancing.

Irrespective of market design, the twenty-four hour period is a necessary part of unit commitment decisions made for other resources. For example, BPA's interconnected hydro operations require decisions to be made in advance so that water can move from one reservoir to another. Thus, the Commission should not assume that a shorter commitment period would come without costs to other resource operations.

Question 5. Should the financial risk of VERs' participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs' participating in the day-ahead market? If so, what are they?

BPA is developing a "self-supply" project that is expected to enable VERs to better manage their own variability through self provision of the imbalance portion of balancing reserve capacity. Under this pilot project, a single entity that owns or contracts with both VERs and dispatchable generation will net its VER schedule deviations with its dispatchable generation, effectively balancing the VER's variability. As long as netting of schedule deviations does not harm other parties or place inappropriate or excessive demands on the balancing authority's balancing reserve capacity requirements, netting would allow dispersed VERs to control their aggregate deviations to some extent. However, because netting is the equivalent of forming a small balancing pool without the full set of responsibilities assigned to a formal balancing authority, the approach probably results in some loss of efficiency in capacity use to balance the VERs. As recognized elsewhere in these comments, pooling diversity across larger areas has the potential to reduce the total amount of balancing capacity required.

VERs that are able to effectively net schedule deviations and self-provide balancing resources to firm up generation within the hour may be able to participate more actively in the day-ahead firm energy market. Since the day-ahead markets in the Pacific Northwest trade in equal amounts of power over the heavy load hour or light load hour periods, VER sellers of firm day-ahead products will need to deploy additional capacity resources in order to meet firm commitments when the VER does not operate.

A key factor in enabling market transparency is to ensure that product definition and identification is clear and transparent. If the Commission intends to allow a variety of solutions to the issues associated with the provision of VER balancing reserve capacity, product identification must reflect that variety. All entities in the market must understand from the tag the identity of the provider and the quality of the balancing reserve capacity behind the product that is being sold. This ensures that all parties to the transaction are aware of any financial and operational risk associated with the VER schedule. The increase in development of VERs may result in development of additional markets for products that reflect the risks associated with different sources of generation. These additional markets may be necessary to send price signals to incentivize the development of generation capacity necessary to integrate increasing amounts of VERs. These markets should complement existing markets rather than replace them.

Accordingly, the Commission should not institute measures that relieve some parties in a commodity market of financial risk at the expense of other market participants. To the extent that risk is different for different products, that risk should be transparent and should be reflected in the value that the market assigns to that product.

Question 6. Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

The lack of tag transparency on the firmness of VER output may be keeping VERs in the hour-ahead market. As long as VERs are tagged as firm power, there is a large financial incentive to capture day-ahead or monthly firm power prices by using VER output to source day-ahead or monthly firm power sales using the hour-ahead market. BPA's experience is that the cost of balancing reserve capacity to maintain transmission schedules for the hour-ahead market without curtailment is more than VER developers are willing to pay. Developing new product descriptions for VERs would allow development of new commercial products to support VERs. These new products could be traded in day-ahead markets, or VER output could be combined with new commercial products, which would increase the potential for VERs to sell their output as firm power in day-ahead markets.

C.2. Reliability Commitments

Question 1. 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?

Currently, BPA commits resources for meeting load and for reserve capacity on an hourly basis but only uses Federal resources to meet the differences between the day-ahead forecasts, the hour-ahead schedules, and actual usage. To balance changes in wind and load, however, BPA currently holds enough capacity to meet 99.5% of the in-hour variability throughout a rate period. BPA's rationale for holding this amount of capacity assumes that BPA will continue to implement DSO 216. BPA forecasts these capacity needs in its rate cases every two years and uses these forecasts to plan its system obligations and price these capacity reserves.

Increased accuracy in forecasting, rather than additional reliability assessments and commitment processes, likely will drive a reduction in reserve requirements. BPA recommends that the Commission not mandate the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour.

Question 2. 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?

BPA does not participate in the same reliability commitment processes in which an ISO might participate. However, BPA recommends that the Commission not mandate the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour. A formalized intra-day reliability assessment would not provide any benefits to markets in the Pacific Northwest.

Question 3. What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?

BPA believes balancing authorities should explore a combination of centralized and decentralized forecasting and the Commission should not require balancing authorities to implement centralized forecasting. If a balancing authority implements a centralized regional forecasting system that produces accurate next-day forecasts, the forecast should be one of the inputs to the existing reliability assessment and commitment processes.

As discussed in BPA's response to questions in Part III, Section A, BPA believes that the Commission should consider requiring VERs to provide forecasts to the source balancing authority. The source balancing authority could then use these forecasts for reliability assessment and commitment to aid in evaluating intra-day needs for reserve capacity.

D. Balancing Authority Coordination

BPA supports the Commission's efforts to explore the benefits of increased balancing authority coordination. The Pacific Northwest is already engaged in several initiatives aimed at improving coordination and efficiency in the region.[18] In BPA's experience, load diversity and the geographical diversity of resources are the two primary factors that tend to lower the amount of balancing reserve capacity needed to accommodate the variability of VERs. Small balancing authorities and generation-only balancing authorities tend to lack load diversity and geographical resource diversity. As a result, such balancing authorities will likely carry higher integration costs than larger balancing authorities. Improved balancing authority coordination will enable existing balancing authorities to take advantage of the diversity of VER output and load in other balancing authorities, which should reduce inefficiency and VER integration costs

[18] *See* Part I, pp. 8-15.

The Commission's questions identify several approaches to optimizing the benefits of resource diversity and facilitating the integration of VERs across the interconnected grid, including balancing authority area consolidation or the creation of a large area VER balancing authority. Over the years, there have been several failed attempts at balancing authority consolidation in the Pacific Northwest. BPA believes that regional collaboration driven by local cost and benefit analysis will continue to drive current efforts towards to broader balancing authority coordination, such as activity underway at the Columbia Grid/NTTG/WestConnect Joint Initiative. Broader utilization of balancing authority coordination tools such as dynamic transfer—although limited—can provide many of the benefits of balancing authority consolidation at potentially lower costs. BPA recommends:

- The Commission should continue to encourage balancing authority coordination but allow regions to determine whether and when more formal consolidation should be accomplished.

- The Commission should not actively promote virtual balancing authorities that are simply large, geographically diverse sets of VERs, which would lack significant load and resource diversity.

- The Commission should not actively encourage the creation of small generation-only balancing authorities. If the Commission does provide the opportunity for small generation-only balancing authorities, it should apply the same reliability requirements to those types of balancing authorities that apply to all other balancing authorities.

Question 1. Will smaller balancing authorities, when operated individually, have higher VER integration costs than geographically or electrically larger balancing authorities? If so, why?

In general, smaller balancing authorities will have higher VER integration costs than geographically or electrically larger balancing authorities. In BPA's experience, two factors may lead to lower VER integration costs: (1) the geographic diversity of VERs and (2) load diversity. Smaller balancing authorities, when operated individually, are unable to take advantage of either of those factors, which will likely lead to higher VER integration costs.

The lack of geographic diversity of VERs within a balancing authority area creates serious challenges for a smaller balancing authority. BPA has run a number of studies on the balancing reserve capacity needs for VERs over a wide range of VER penetration levels and has reviewed numerous other studies concerning this issue. These studies have consistently found that the greater the geographic diversity associated with a large amount of VERs, the less balancing reserve capacity is needed per installed MW of VERs.

Most of the wind generation in BPA's balancing authority is located in a relatively small geographic region along the Columbia River Gorge. Because weather patterns in a small geographic region are similar, simultaneous ramping of these VERs occurs, requiring greater amounts of balancing reserve capacity to meet the variability than would be required if the VERs were geographically dispersed. Balancing the wind ramps of a geographically concentrated wind fleet has been a challenge for BPA, and smaller balancing authorities likely will have a similar lack of geographic diversity of VERs, leading to higher VER integration costs than in larger balancing authorities. Balancing authorities with VERs spread over large geographic areas are more likely to experience different weather patterns and ramp events across the system, which can result in less overall variability for the balancing authority to manage. However, increasing the size of a balancing authority area may not automatically reduce the reserve requirement and costs associated with integrating VERs.

Smaller balancing authorities may have higher balancing reserve capacity requirements due to the lack of load and load diversity. When performing the balancing function, all load and generation in the balancing authority contributes to the amount of balancing reserve capacity that is required to maintain reliability. When a balancing authority has a large amount of load compared to the installed capacity of VERs, the VERs' change in output is more likely to be partially offset by the load variability. In other words, greater load and load diversity in a balancing authority can help dampen the impact of variability and uncertainty in VER output. Smaller balancing authorities have less capability to absorb larger errors without violating NERC Resource and Demand Balancing (BAL) Standards, in part due to the lack of generation and load diversity in their balancing authority area.

Finally, a smaller balancing authority is likely to have higher costs associated with the acquisition of additional balancing reserve capacity than a larger balancing authority. Since a small balancing authority may not have the internal dispatchable generation resources to meet the VERs' variability, the small balancing authority will likely have to acquire in-hour balancing reserve capacity from a different entity.

Question 2. Should the Commission encourage the consolidation of balancing authorities? If so, indicate the potential for and impediments to consolidation among balancing authorities and the means by which the Commission should encourage consolidation.

The Commission has encouraged the consolidation of balancing authorities for the last decade, starting with Order Nos. 888, 889 and 2000. Based on BPA's experience with consolidation efforts in the Western Interconnection, however, more benefits can be gained from regional coordination efforts than from consolidation of balancing authorities at this time. Regional coordination and standardization have the benefit of leveraging existing processes and organizational structures such as the Northwest Power Pool. Regional coordination has the further benefit of helping to develop solutions tailored to particular statutory requirements and other characteristics of the entities involved. BPA and other balancing authorities in the Pacific Northwest currently are coordinating on initiatives such as intra-hour scheduling and dynamic transfer, and tools such as contingency reserve sharing protocols are already in place. The fundamental question from BPA's perspective is what additional benefits would formal consolidation provide and do those benefits outweigh the complications and disadvantages discussed below.

Balancing authorities in the Pacific Northwest have made several attempts at creating a new organization to administer a consolidated balancing authority in the past. The organizations include IndeGo, RTO West and GridWest. These previous attempts resulted in the general perception that the benefits of consolidation would not outweigh the costs and other challenges. The region has since come to agreement in certain areas to take advantage of some of the attributes of consolidation without actually forming an ISO or RTO. This model of regional cooperation has made progress toward achieving the benefits found in RTO-like structures. Although full balancing authority consolidation appears to be far off the agenda of many regional parties, the region has initiated dialogue around the potential advantages of virtual balancing authority consolidation from a fresh perspective given the changing nature of the electric industry and the issues raised by VER integration. The success of these efforts likely will depend on the perception that the potential benefits outweigh the potential costs and risks. It is also important to certain parties, including BPA, that any new structures do not create additional layers of Commission oversight and do not conflict with other statutory requirements.

As discussed in Part III, Section D, question three, BPA recommends that the Commission should encourage greater balancing authority coordination while allowing regions to determine individually when and if the time for broader consolidation is right. The Commission should allow balancing authorities within an interconnection to use available tools and to implement regional solutions to VER integration. As explained above, BPA does not believe that consolidation of balancing authorities is necessary to successfully integrate VERs reliably and economically.

Question 3. What tools or arrangements (*e.g.*, dynamic schedules, pseudo-ties, and virtual balancing authorities) are available and/or could be enhanced or created to reduce barriers to greater operational coordination among balancing authorities? What role should the Commission play in facilitating inter-balancing authority coordination?

BPA has utilized dynamic schedules and pseudo-ties for multiple applications but on a fairly limited basis. In early 2009, BPA began to analyze the attributes and limitations of dynamic transfer capability. BPA embarked on an innovative, forward-looking study to analyze the issues associated with dynamic transfers and find the limits on some of the key congestion points on the system. BPA found that, with the current reactive support and special protection systems (*e.g.*, remedial action schemes), there is little dynamic transfer capability available in the Northwest. Increasing the amount of dynamic transfer capability requires system improvements such as substantial upgrades to reactive support on the transmission system, automation of reactive device switching and automation to arming and disarming remedial action schemes. The technical limitations associated with dynamic transfer capability are explained in Part III, Section B.1, question three and Part III, Section D, question seven.

BPA is working with many other entities to streamline the communications needed to implement dynamic transfer. A joint effort is currently underway to develop a dynamic scheduling system that would allow dynamic transfers by multiple entities without building the communication infrastructure between each individual entity that is currently required. These efforts are described in further detail in the "Comments of the Joint Initiative Facilitators" filed in this docket.

One of the more promising uses of dynamic transfer as a tool for addressing issues associated with the integration of VERs is to facilitate operational coordination among balancing authorities. Dynamic transfers may be used to allow balancing authorities to pool the diversity of load and VERs across regions. This would result in decreasing the amount of reserves required for VER integration.

Dynamic transfers may also be used by VERs to self-supply a portion of the balancing reserves needed to integrate those facilities. BPA is implementing a self-supply pilot program this year. If successful, self-supply will allow BPA to displace a portion of the balancing reserve capacity it provides to reliably integrate VERs and give VERs the opportunity to find lower-cost balancing resources.[19]

In addition, BPA advocates continuing work on defining the concept of a virtual balancing authority. BPA envisions a virtual balancing authority as a mechanism that allows more sharing of balancing reserve capacity between conventional balancing authorities that contain both generation and load. Use of dynamic transfer in this context creates the potential for taking advantage of the diversity of geographically dispersed VERs where possible. BPA does not see particular value in a virtual balancing authority that is simply a large, geographically diverse set of VERs because such a balancing authority would lack load and resource diversity. The limitations are discussed more fully in Section D, question six below.

Dynamic transfers and pseudo-ties can be utilized to enable virtual balancing authorities, self-supply of balancing reserve capacity and greater operational coordination among balancing authorities. As these tools are expanded, the virtual balancing authority concept may be further explored and self-supply of balancing reserve capacity may be expanded.

One of the first steps in determining the full potential of dynamic transfer is assessing dynamic transfer capability on an interconnection-wide basis. Once these assessments have been

[19] BPA notes, however, that a VER that self-supplies a component of in-hour balancing reserve capacity may cause an increase to the total balancing reserve capacity requirement for other VERs purchasing such balancing reserve capacity from the balancing authority. This is because the removal of the self-supplying VER results in a decrease to the overall diversity pool in the balancing authority.

completed and more system constraints are identified as the use of dynamic transfers expands, transmission providers and transmission operators will need to perform additional studies to evaluate the impact of dynamic transfers and identify the need for additional facilities, infrastructure, and control strategies. Transmission providers and transmission operators must be able to recover the associated costs from those entities that create the need for new dynamic transfer capability. As stated in Part III, Section B above, to the extent that the Commission modifies its policies relating to dynamic transfer or considers incorporating new provisions into the *pro forma* tariff, such changes should accommodate both the need to recover related costs and the need to retain adequate flexibility for using dynamic transfer as a tool in integrating VERs.

Question 4. What are the costs and benefits, if any, associated with the proliferation of small generation-only balancing authorities? How do NERC Certification and Reliability Standards encourage or discourage the creation of small generation-only balancing authorities?

BPA is not an advocate of small generation-only balancing authorities, but understands the forces that have motivated some entities to create such balancing authorities. BPA is concerned that there would be significant cost shifts if there was an increase in the number of small generation-only balancing authorities. As explained in response to question one in this section, small generation-only balancing authorities will lack the benefit of geographic resource or load diversity. If a small generation-only balancing authority holds less within-hour balancing reserve capacity than necessary, the imbalance experienced by the generator(s) would be captured by inadvertent interchange rather than generation imbalance. If this were to occur, adjacent balancing authorities would experience inadvertent interchange accumulations. Small generation-only balancing authorities also may require additional coordination with adjacent balancing authorities to meet the criteria in the NERC BAL, EOP, INT, and TOP standards. This would further burden adjacent balancing authorities.

NERC's reliability standards both enable and constrain the creation of small generation-only balancing authorities. For example, NERC Standard BAL-001-0.1a enables small generation-only balancing authorities by allowing long periods in which the generator does not need to correct its forecast error and associated schedule errors because the error is accounted for in the balancing authority's inadvertent interchange. Relying on inadvertent interchange does not carry the same costs as carrying sufficient quantities of responsive generation imbalance capacity, resulting in a monetary benefit to the small generation-only balancing authority at the expense of the other balancing authorities in the interconnection.

The proposed NERC Reliability Based Control standard, which has been in field trial for over four years, encourages small generation-only balancing authorities by allowing even more of this type of "leaning" on the interconnection than is allowed by NERC Standard BAL-001-0.1a, R2. More leaning on the interconnection means that generation-only balancing authorities can go for long periods without meeting its interchange obligations. It is essential that small balancing authorities carry sufficient balancing reserve capacity required to meet minimum control needs.

Conversely, the volume of NERC Standards with which balancing authorities are required to comply discourages small generation-only balancing authorities. A violation of any of the NERC Standards may result in potential sanctions that far outweigh any generation imbalance penalties. This is one of the inputs to the cost and benefit analysis that the small generator would consider in determining whether to be included in a small generation-only balancing authority.

BPA recommends regional collaboration on policies and business practices to establish common requirements for the amount and characteristics of the balancing reserve capacity that balancing authorities should hold.[20] Regional standardization of balancing reserve capacity requirements should help to address problems with leaning on the interconnection and exporting balancing deficiencies to other balancing authorities, and produce greater transparency and consistency in the wholesale markets for VER generation. BPA anticipates that the WECC Variable Generation Subcommittee and other western forums will address these issues in the foreseeable future.

Question 5. The Commission is interested in receiving comments on whether the integration of VERs with small host balancing authorities may limit the benefits derived from geographical diversity and increase integration costs. Should the Commission encourage and/or facilitate the creation of a VER balancing authority, essentially a large area virtual balancing authority primarily designed to accommodate VERs across a broad geographic region? What would be the benefits and costs of creating such a large area entity?

As explained in BPA's response to question one in this section, integration of VERs in small host balancing authorities significantly reduces the benefits derived from load and VER geographic diversity. A large area virtual VER balancing authority may suffer from similar drawbacks. Although a large area virtual VER balancing authority may take advantage of geographic diversity, it lacks the benefits derived from load diversity. Rather than encourage the creation of VER balancing authorities, the Commission should promote coordination among traditional balancing authorities to better meet VER balancing needs. Coordination among traditional balancing authorities could take advantage of the diversity of VER output and load among the different balancing authorities. A VER-only balancing authority would require more reserves than a large virtual balancing authority leveraging the diversity within multiple

[20] *See also* Part III, Section E, pp. 83-103.

traditional balancing authorities. A large virtual balancing authority consisting of multiple balancing authorities with load and generation could take advantage of both VER geographical diversity and load diversity. A large VER-only balancing authority also would cause more energy flows on the interconnection and necessitate more infrastructure additions, because the VERs would still require access to dispatchable generation for balancing needs.

A large area virtual VER balancing authority presents other risks as well. The dynamic transfers created by the large area virtual VER balancing authority will likely require costly infrastructure upgrades that would be unnecessary without the virtual VER only balancing authority. BPA explains this issue in more detail in its responses to the next two questions.

Question 6. Would a large area VER balancing authority be capable of capturing the reduced variability of VERs located across a broad and geographically diverse region? What tariff or technical limitations would prevent and/or inhibit the development of a large area VER balancing authority?

BPA believes that a large area VER balancing authority is not the most economical method to integrate VERs and technical limitations may diminish the potential benefits of this concept in certain regions. A large area VER balancing authority would capture the diversity of the variability of VERs located across a broad, geographically diverse region, but would not have the advantage of the load and dispatchable generation across the same region to reduce the balancing reserve capacity needed for the VERs. Due to the lack of load diversity in a large area VER balancing authority, the balancing authority likely would have higher balancing reserve capacity requirements. The large area VER balancing authority would need to access dispatchable generation in some manner to maintain reliability. Options such as existing balancing authorities sharing reserve needs via a virtual balancing authority should produce more benefits in terms of reducing balancing reserve capacity requirements.

Technical limitations also would affect a large area VER balancing authority's ability to capture the reduced variability of VERs located across a geographically diverse region. With a large area VER balancing authority, differences in output of the geographically dispersed VERs would have to be dynamically transferred across transmission systems that are not currently supporting such dynamic transfers. Although enhancing the ability to dynamically transfer the variability and diversity of VERs between existing balancing authorities may reduce the reserve needs for large regions, lack of dynamic transfer capability in a region would limit or even eliminate the ability of a large area VER balancing authority to capture the benefits of the regional diversity. As discussed previously, dynamic transfer capability in the Western Interconnection is limited. The ability of other systems to support significant amounts of dynamic transfer is unknown. Given these limitations and lack of information, it would be more cost-effective to use the available dynamic transfer capability to support viable solutions currently being studied by traditional balancing authorities, such as allowing VERs to self-supply a component of the balancing reserve capacity, acquiring balancing reserve capacity from other resources, and dynamically transferring some of the variability to the sink balancing authorities. Sharing reserve needs between balancing authorities would not require as much dynamic transfer capability as a large area VER balancing authority because the balancing authorities integrating the VERs would be able to deploy dispatchable resources in the same region as the VERs prior to transferring the variability to other balancing authorities. Using existing tools and enhancing balancing authority coordination will provide similar or greater benefits without the additional costs associated with increasing dynamic transfer capability to facilitate large area VER balancing authorities.

Although BPA does not advocate development of a large area VER balancing authority, the *pro forma* tariff does not appear to inhibit development of such a balancing authority. BPA is opposed to any modification to the *pro forma* tariff that would provide special considerations for VER balancing authorities. Instead, balancing authority requirements should be left to the reliability standard process and all balancing authorities should be subject to the same reliability and area control requirements.

Question 7. What reliability impacts may be associated with the creation of a large area VER balancing authority?

The primary reliability impact associated with the creation of a large area VER balancing authority would be the change in flows across an interconnection due to the interaction of geographically diverse VERs. Under the traditional balancing authority structure, the VER variability has been balanced in the source balancing authority for the most part, thereby avoiding dynamic transfers across multiple transmission systems in the interconnection.

A large area VER balancing authority would change the traditional balancing authority structure because it presumably would span multiple transmission systems, but it would not own or operate transmission. The system operators within the large area VER balancing authority would remain responsible for operations. One reliability impact under these circumstances would be associated with the need for dynamic transfers across the multiple transmission systems within the VER balancing authority. Transmission operators with systems that are "intermediary" systems for purposes of transfers across the balancing authority, or that are adjacent to the VER balancing authority, would be responsible for maintaining system voltage. The dynamic transfers between the VERs of the VER balancing authority, however, would cause voltage deviations that transmission operators currently cannot manage. There is a high likelihood that the available reactive support would be insufficient for the additional dynamic transfers, which would necessitate the installation of additional reactive support devices. In many cases, transmission operators would need to install devices such as static VAR compensation that can automatically regulate output to compensate for the voltage changes caused by dynamically changing energy transfers.

The adjacent and intermediary balancing authorities would incur costs to automate switching of the new reactive devices, as well as to retrofit the current infrastructure in order to automate switching of the reactive devices already installed. Where reactive support is available, it typically does not have the control systems necessary to automatically change output to follow the dynamic transfer impact on system voltage. With a large amount of dynamic transfers, transmission operators would have difficulty manually ensuring an adequate amount of reactive support on the system. The required automation would include programming changes at the control centers and the communication infrastructure needed to ensure reliable automated switching of the reactive devices.

Transmission operators or their respective balancing authorities would also be responsible for arming and disarming special protection systems due to the system variability created by the VER balancing authority. When the generation pattern changes over large areas, the special protection system dispatcher must disarm generation dropping where the generation decreases or arm generation dropping where the generation increases. Currently most arming and disarming of generation dropping for special protection systems is done manually, both in the control center and at the device. Manual operation has created problems with dynamic transfers in the past because the dynamic transfers required the arming and disarming to occur multiple times during the hour. Since the special protection system is set up to ensure reliability of the interconnection, until the dispatcher is able to arm or disarm the generation for dropping, the interconnection is being operated in a compromised state. As a result, automation of the special protection systems would be required to accommodate a large area VER balancing authority.

Automation of the central special protection systems algorithms and installing the communication capability to the devices in the field that arm or disarm the generation dropping would be an extremely costly undertaking. In addition, these systems cover multiple balancing authorities across the Western Interconnection, including Canadian balancing authorities. Automating these systems across balancing authority areas increases the costs associated with the communication infrastructure as well as the costs associated with the complex programming required.

The burden of adding the infrastructure required to accommodate a large area VER balancing authority falls on the balancing authorities that are adjacent and intermediary to the large VER balancing authority. Cost causation principles dictate that the burden of this additional expense must be borne by the large area VER balancing authority and not the affected balancing authorities. This could be accomplished with a cost-recovery mechanism, as recommended in BPA's response in Part III, Section B.1, question three and Part III, Section D, question three above.

Question 8. Should a large area VER balancing authority be limited only to VERs? Why or why not?

BPA believes that it is sub-optimal to exclude non-VER generators and demand-responsive loads as part of a balancing authority. Keeping area control error in check for a VER-only balancing authority will require contracting with dispatchable resources. Adding dispatchable resources and loads to the mix would benefit a virtual balancing authority by providing balancing reserve capacity and reduced balancing requirements. BPA's responses to other questions in this section describe other problems presented by the creation of large area VER balancing authorities.

Question 9. Should the Commission consider establishing specific policies that support the creation of a large area VER balancing authority? If so, why?

The Commission should not establish policies to support creation of a large area VER balancing authority for the reasons explained in BPA's previous responses in this section. The absence of load diversity or dispatchable generation in a large area VER balancing authority increases the need for balancing reserve capacity, which offsets the benefits of the geographical diversity of the large area VER balancing authority. Further, the cost of additional infrastructure required to accommodate a large area VER balancing authority is substantial. The regional advantages derived from keeping the traditional balancing authority structure and removing barriers to sharing the variability of VERs and balancing reserve capacity responsibilities provides more benefit at lower costs.

If the Commission does consider policies promoting large area VER balancing authorities, it should require such balancing authorities to abide by the same requirements as all other balancing authorities, specifically area control error requirements. In addition, there should be no shift of risk or cost between existing balancing authorities and a large area VER balancing authority. If large area VER balancing authorities are placed on equal footing and held to the same standards as existing balancing authorities, the economics of creating large area VER-only balancing authorities will most likely discourage creation of such balancing authorities.

E. <u>Reserve Products and Ancillary Services</u>

Section E of the Notice explores whether variability associated with increased VER deployment results in over-reliance on expensive reserves such as regulating reserves. The rapid increase in VERs connected to BPA's system in recent years has required BPA to consider the reserve issues raised in section E. BPA's responses to the specific questions in section E include the following primary themes:

- Existing reserve products are not the most cost-effective means of supplying reserves needed for VERs or extreme VER ramp events. Although certain reforms described in the Notice should help to more reliably and cost-effectively integrate VERs, other measures are necessary to clarify the amount of reserves to hold for VERs and the deployment responsibilities of source and sink balancing authorities.

- Schedule 9 of the *pro forma* tariff could be interpreted to obligate the source balancing authority to carry unlimited reserves to balance VER output even if the output is exported to serve load elsewhere. Requiring the source balancing authority to carry unlimited amounts of reserves to balance exports of VER output is economically inefficient.

- Balancing authorities should be allowed to establish a new type of service to provide a clearly defined quantity of balancing reserve capacity for the uncertainty associated with VER generation. The Commission should encourage regional collaboration in determining the amount of balancing reserve capacity to set aside and the specific characteristics of the reserves.

- The Commission should require each VER generator and any associated load serving entity to develop a plan for procuring the balancing reserve capacity for its resource and document this plan in its interconnection agreement with the source balancing authority.

- Allowing the sink balancing authority to deploy contingency reserves when the entire amount of balancing reserves provided by generators in the source balancing authority has been deployed makes economic sense under the current market paradigms. In the long run, however, it may be more appropriate to promote development of intra-hour markets, rather than relying on contingency reserves.

- Reserve sharing programs appear to be an effective means to minimize duplication of reserve deployment capability. Clarifying the type and amount of reserves for VER balancing should help facilitate development of these programs.

- VERs should be required to have the capability to provide generation decrease reserves (decremental capacity) and reactive power reserves, and all resources, including VERs, should be capable of providing frequency response.

Question 1. 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?

In BPA's experience, existing reserve products do not provide system operators with sufficient means to maintain reliability during VER ramping events. Existing reserve products suffer from a number of deficiencies, including a lack of definition of the type of reserve to hold and deploy for ramps and a lack of clarity regarding the amount of reserves to hold and on whether the source balancing authority or the sink balancing authority will deploy the reserves. For example, the amount of contingency reserves to hold is well-defined, but the purpose of these reserves is to respond to outages of dispatchable generation rather than VER ramps. On the other hand, operators can deploy regulating reserves and reserves for load following in response to VER ramp events, but the minimum amounts that operators must hold are undefined.

To address the deficiency in the existing products, BPA has created an additional reserve product, which it generally refers to as "balancing reserve capacity," to account for the capacity implications of increased following requirements and stochastic and heavy use of imbalance energy. This capacity product consists of regulation, spinning, and non-spinning reserves. In addition, BPA has adopted the operating protocols in DSO 216 to allow BPA to order feathering of wind generation or curtailment of transmission schedules when BPA comes close to exhausting the balancing reserves as a result of over- or under-generation by the wind fleet.[21] These operational protocols effectively control the amount of balancing reserve that BPA deploys for VER ramping events.

[21] *See* Part I, Section C, pp. 12-15.

Even though most VER generation in BPA's balancing authority is exported, BPA currently holds enough balancing reserve capacity to meet all but the most extreme ramping events of VERs and load (this amount of balancing reserve capacity assumes the continued operation of DSO216 in BPA's balancing authority). Requiring the source balancing authority to hold almost all the required reserves does not appear to be the most efficient means of maintaining reliability. There should be cost or capacity savings associated with the sink balancing authority providing the reserves instead of the source balancing authority when VER output is being exported. Because the sink balancing authority must be able to acquire generation to fully serve load, there is likely some duplication of capacity allocation if the source balancing authority is required to provide within-hour balancing while the sink balancing authority provides hour-to-hour coverage.

Requiring a source balancing authority to hold reserves to meet almost all VER ramping events also is inconsistent with load service responsibility principles. A source balancing authority should not be the default supplier of reserves for VER generation, especially if that generation is exported out of its balancing authority. Instead, the responsibility for planning for the balancing needs of a VER resource should be managed between the VER generator and any associated load serving entity.[22]

Key factors for lowering balancing reserve capacity requirements are more accurate forecasting and scheduling. BPA studies have shown that up to 70% of the in-hour balancing reserves needed are associated with forecast error. Since perfect forecasts are unattainable, implementing some combination of the other reforms suggested—intra-hourly scheduling, more use of dynamic transfers and pseudo-ties, and virtual balancing authorities or dynamic reserve

[22] *See* Part III, Section E, Question Three, pp. 88-91; *see also* Part II, pp. 15-31.

sharing among balancing authorities—should help to address some of the current challenges with VERs. Although these reforms should be helpful, implementing them would not eliminate the need for regions to collaborate on common business practices and policies regarding balancing reserve capacity and hour-to-hour flexibility in generation capacity (similar to non-spinning reserves) needed for VERs.

In addition, wind generators should be required to have the capability to feather turbine blades so that they can reduce their generation when the source or sink balancing authority cannot accept the increased generation.[23]

Question 2. How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?

BPA's hydro operators and system operators could use more accurate forecasting information to support more efficient deployment of reserve capability for VER output serving loads inside the BPA balancing authority. However, because reserve deployment direction (increment or decrement) is related primarily to VER scheduling error, better VER output forecasting alone does not translate directly to reduced reserve requirements on a short-term basis. VER schedulers must actually use the improved forecast to submit more accurate schedules. BPA currently forecasts its balancing reserve capacity requirements based on a two-year rate cycle, and BPA's forecast of balancing reserve capacity requirements should decline if VER scheduling accuracy improves as a result of better forecasting or because of a shift to more frequent scheduling windows or automated persistence-based scheduling. Even if these types of improvements occur, however, hour-to-hour flexibility in generation resources will still be needed to ensure that load is served.

[23] *See* Part III, Section E, Question Nine, pp. 96-98.

Question 3. 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?

In developing its balancing reserve product, BPA analyzed the contribution of regulation, following (change over ten-minute intervals) and imbalance (schedule error) to the total reserve requirement. To determine the total balancing reserve capacity requirement, BPA focused on addressing the net impact to generation units on automatic generation control caused by variation of all generation and load in the balancing authority. VER output, VER schedule error, and load variability were key drivers of the total reserve requirement, and BPA allocated the impacts to either load or generation for ratemaking purposes. BPA found that, as the amount of wind generation in its balancing authority increased, demand for following and regulating reserves increased a modest amount, but demand for imbalance reserve capacity increased significantly.

BPA also estimated the allocation between spinning and non-spinning reserve requirements in developing its balancing reserve product and partitioned the requirements into incremental and decremental generation capacity reserves. From both operational and cost-analysis perspectives, the distinction between spinning and non-spinning reserve requirements was more significant than the distinction between regulation, following, and imbalance reserves. BPA found that a significant portion of the reserve requirement for incremental reserves could be carried as less expensive non-spinning reserve.[24]

This analysis informed the creation of a new category of reserves for BPA's wind balancing service. A portion is carried as spinning reserve and a portion is carried as non-

[24] It should be clarified that the ability to hold balancing capacity reserve as non-spinning reserve only applies to incremental reserve capacity. Decremental reserve capacity must be held on units that are spinning.

spinning. The product includes both incremental and decremental reserves that are carried continuously to respond to variation in wind and load.

Based on BPA's experience with the balancing reserve capacity for its wind balancing service and the issues raised in the Notice, there appears to be a need for balancing authorities to charge for the regulation, load following, and generation imbalance capacity components that are required to manage the variability of VERs.

BPA believes that regional stakeholders should have the responsibility to coordinate on the specific amount and characteristics of the balancing reserve capacity that is necessary to support VERs.[25] The questions in this section focus on whether a balancing reserve capacity product like following reserve or contingency reserve would be more appropriate, but each region should be able to focus on defining the balancing reserve capacity necessary to manage VERs without having to try to conform to the existing reserve products. In general terms, balancing reserves should include specific amounts of spinning and non-spinning reserve capacity and incremental and decremental reserves. The balancing reserve also should be dispatchable on relatively short time frames for the most part (*i.e.*, 10, 15, or 30 minutes).

Given that the accuracy of wind schedules drives the majority of within-hour balancing reserve capacity needs, methods to develop reserve requirements should also account for impacts of schedule frequency or other efforts that reduce schedule errors. Schedule error will relate directly to the frequency of schedule adjustments, so reserve product design should be flexible enough to accommodate various scheduling intervals. Finally, because schedule error may relate directly to operator behavior as well as forecast inaccuracy in some cases, balancing authorities

[25] As discussed elsewhere in BPA's comments, once the balancing reserve capacity requirements are understood, there should be multiple options as to the entity responsible for providing the reserves and the source balancing authority should not be the default supplier.

need to be able to detect and penalize patterns of error that seem inconsistent with "persistent" or unbiased forecast error, as described in Part III, Section B.1, question two of BPA's response.

In order to clarify and provide certainty with respect to the responsibility for providing balancing reserves, VER generators and the load serving entities purchasing the output on a long-term basis should be obligated to develop a balancing plan for procuring capacity for the balancing reserve capacity needs of a particular generator. Requiring such a balancing plan will help establish that the source balancing authority will not be treated as a default supplier of balancing reserve capacity, especially in cases where the VER output is exported to serve load outside that balancing authority. The Commission should add provisions to the interconnection requirements in the *pro forma* tariff to require VER generators and any associated load serving entity to document this balancing plan in the VER generator's interconnection agreement. This would require the generator and any load serving entity to consult with the source balancing authority in developing the balancing plan and determine if it is workable for all parties. A VER generator may have a number of options for its balancing plan, such as dynamic transfer of its output to another balancing authority if capability is available, self-supply of its needs from resources within the source or sink balancing authority, or purchase of the balancing reserve capacity directly from the source balancing authority to the extent it is able to supply them within applicable operating limitations. Other options may be available as well and could be defined in the VERs' balancing plan.

Regional determination of the characteristics of balancing reserve capacity and the amount of reserves to hold, along with the development of specific balancing plans for procuring balancing reserve capacity for particular VER generators, should allow generators to more easily offer their output for balancing service and allow dispatch across balancing authorities, to the extent dynamic transfer capability is available. Prices for balancing reserve capacity theoretically should stabilize as more generators are able to offer balancing reserve capacity, and it becomes easier to call on both spinning and non-spinning generators to change their dispatch so that supply keeps pace with demand.

Question 4. 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. 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 Commission should not separate the question of whether contingency reserves should be available to respond to extreme VER events, and, if so, how they should be deployed and by whom, from the broader discussion of VER balancing reserve capacity requirements. The Commission should consider the discussion of contingency reserves that follows in the context of BPA's response to the other questions in this section, including the need for regional definition of the amount of balancing reserve capacity to hold, and other proposed reforms as a whole.

Groups within WECC and the Northwest Power Pool are discussing whether extreme VER events (*e.g.*, rapid, unforecast increases or decreases in wind generation) should be considered contingency events and, if so, how to identify those events. BPA recommends that the "event" that should trigger any use of contingency reserve should be depletion of other types of reserve capacity (*e.g.*, balancing reserve capacity) rather than a particular type or definition of extreme VER events. Each time that BPA has come close to depleting its balancing reserve capacity, it has been due to large control errors associated with wind generation.

Attempting to define all of the qualifying VER-related events that would trigger contingency reserve deployment would be difficult given that unanticipated circumstances will arise, and determining that an event meets that definition could be problematic for operators with a limited time to respond. Objective standards such as depletion of other reserves would provide more certainty in this situation.

Requiring balancing authorities that export wind generation to carry reserve capacity for the full range of variability of a VER generator that is exporting its output may not make economic sense when the sink balancing authority is holding generation flexibility to manage hour-to-hour variability for the same resource.[26] Use of contingency reserve for VERs may promote more efficient use of reserves for wind balancing and that the sink balancing authority should provide the reserve when a trigger event occurs. BPA will continue to engage this topic with regional stakeholders through the Northwest Power Pool and other forums.

For the long-term, it may be appropriate to promote development of dynamic transfers and intra-hour scheduling, but as described previously in this response, there are challenges to implementing these approaches. Although there may be some duplication of capacity requirements when the source balancing authority is required to provide balancing reserve capacity, there are also difficulties with fully transferring the reserve capacity obligation, such as limits on dynamic transfer capability. Intra-hourly scheduling does not fully transfer the responsibility for balancing within the defined scheduling period.[27]

Finally, to the extent that the source balancing authority is providing balancing reserve capacity for exported VER output, it must be able to limit the reserve demand on its resources. To ensure the limit is enforceable, the source balancing authority needs to be able to limit schedules when the amount of balancing reserve capacity is fully deployed. BPA maintains system reliability and limits the demand on balancing reserve capacity through DSO 216.

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[26] For discussion of this issue see Part II, Section C, pp. 20-29.

[27] For discussion of these issues see Part II, Section C, pp. 20-23.

Question 5. 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?

Please see BPA's response to questions E.3 and E.4 above.

Question 6. Could the expanded use of reserve-sharing programs between balancing authorities contribute to lowering the costs associated with integrating VERs? If so, how?

BPA is a member of a Northwest Power Pool reserve sharing program for contingency reserve. Programs such as this are effective at making good use of existing resource capability across multiple balancing authorities. Reserve sharing reduces costs by reducing duplication of contingency reserve obligations. BPA believes that, by extension, it is possible that expanding the use of reserve sharing programs to include balancing reserve capacity could aid in lowering the costs associated with integrating VERs, but this would be a new use of reserve sharing programs.

There are several prerequisites for expanded use of reserve sharing programs to provide balancing reserve capacity. Some of the primary challenges are defining a specific total quantity of balancing reserve capacity requirements for each VER and clarifying which balancing authority has the ultimate responsibility to provide the balancing reserve capacity. Addressing these issues will help ensure that balancing authorities have a common definition of the quantity needed and that balancing authorities and VER operators involved have a clear understanding of their individual responsibilities. The limited dynamic transfer capability between balancing authorities is another important issue, because capacity between balancing authorities would need to be reserved for this purpose. BPA supports reserve sharing but recommends that participation in such programs be voluntary, because regional participants need to resolve the issues associated with determining and developing dynamic transfer service capability.[28]

Question 7. 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?

Schedule 9 of the *pro forma* tariff could be construed to create an open-ended obligation to provide generator imbalance service to any generator located in a balancing authority, regardless of whether that generator serves load in the balancing authority. The Commission should clarify schedule 9 of the *pro forma* tariff. Source balancing authorities should not be required to act as default suppliers of balancing reserves for VER exports. Source balancing authorities should be allowed to clearly define and enforce limits to their balancing reserve obligations.

In addition, the current generator imbalance service under schedule 9 settles for energy only and does not account for the capacity required to accommodate the full range of deviations within any scheduling period, hourly or intra-hourly. To better account for this capacity, it is necessary to charge for the regulation, load following, and generation imbalance capacity components that are required to manage the variability of VERs, similar to BPA's wind balancing service. The Commission should allow balancing authorities to explicitly charge for these balancing reserve capacity requirements on a case by case basis. The Commission should encourage the regions to collaborate regarding the details of these cost-recovery mechanisms.

[28] For discussion of dynamic transfer capability see Part II, Section C, pp. 23-25; Part III, Section B, Question Three, pp. 49-52; and Part III, Section D, Question Three, pp. 73-75.

Question 8. 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?

Pooling programs are a promising source of reduction in overall reserve requirements, because they take advantage of load and generation diversity across multiple balancing authorities. Through the Northwest Power Pool reserve sharing program, BPA and other members have significantly reduced contingency reserve requirements. BPA also is a member of the regional Area Control Error Diversity Interchange Agreement. This regional effort was initiated in 2006, and has resulted in development of a tool through which several of the region's larger utilities pool their area control error. This pooling effort has the benefit of reducing the wear and tear on the regulating units of the participating utilities because it allows them to net out their pooled area control errors, as opposed to following their own signals. This initiative, however, has not yielded reductions in total reserve requirements comparable to the Northwest Power Pool reserve sharing program due to the 30 MW limit placed on participating balancing authorities. Recently there have been some issues regarding application of BAL-001-0.1a to this initiative, but these issues should be resolved in the near term. Expanding participation could reduce reserve requirements, but it will be more beneficial to have a more robust system that shares the balancing reserve capacity deployment, not just the area control error.

BPA also has limited experience with the use of demand response for reserve capacity. Some demand side response can be achieved within ten-minute time horizons, but the reliability of response may be lower than conventional dispatchable generation. BPA has had discussions with demand response aggregators and that option may hold some promise to address this problem. BPA currently is using demand response from two different plants for contingency reserves, and there may be potential to use it for the non-spinning portion of balancing reserve capacity. BPA needs quick, reliable response and needs to develop more automated signaling and resolve questions regarding the interaction between demand response and access to energy imbalance during the response period. If a load resource is allowed to simultaneously provide demand response and access energy imbalance, it becomes difficult to track whether the balancing service was actually provided.

BPA is also conducting initial studies on the feasibility and economics of both greenfield pumped storage and enhancement of existing pumped storage facilities. BPA is working in collaboration with the Bureau of Reclamation and US Army Corps of Engineers on these studies. Pumped storage may prove useful in that it provides integration support without use of thermal resources.

Many of the potential new sources or providers of balancing reserve capacity products will need to rely on dynamic transfer capability to supply the service. As a result, the effectiveness of these new sources or providers may be subject to the scarcity and other potential challenges associated with dynamic transfer capability described previously in BPA's comments.[29]

Question 9. To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?

VERs have the capability to provide decremental balancing reserve capacity and reactive power reserves. VERs can generate below full capacity to provide incremental operating reserves, spinning reserves and frequency responsive reserves. These abilities likely will become

[29] For discussion of dynamic transfer capability see Part II, Section C, pp. 23-25; Part III, Section B, Question Three, pp. 49-52; and Part III, Section D, Question Three, pp. 73-75.

more critical as the amount of VERs on the system increases in order to prevent degradation of transmission system reliability and inequitable cost allocation to other stakeholders.

Contingency Reserves and Decremental Flexibility

Although VERs can theoretically provide contingency reserves, they are unlikely to be a key source in practice. Wind generators cannot be directed to increase their generation unless they have installed governors that keep the generator operating below full capability. Because fuel is generally free for VERs, they are unlikely to be the most cost-effective source of incremental reserves.

In contrast, modern wind turbine generators can accept dispatch signals to reduce their generation output, but they may not be the most economical source of decremental flexibility on a regular basis. VERs have lower fuel costs and other economic incentives to generate, while thermal resources, for example, have economic incentives, such as fuel cost savings, to decrease generation.

Spinning Reserves

To provide spinning reserve services, a generator must be frequency responsive. Governor response modules for wind turbines may be capable of providing meaningful frequency response, but BPA has not observed sufficient performance to confirm this capability. Additional technical evaluation is necessary to assess VERs' ability to provide spinning reserves under these circumstances.

Frequency Responsive Reserves

BPA's response to question 10 in this section includes a detailed discussion of frequency responsive reserves.

Reactive Power Reserves

VER projects are capable of providing dynamic voltage control and reactive power reserve services, either directly or via dynamic VAr equipment located at the project. Wind power plants with type 3 and 4 wind-turbine generators are capable of controlling voltage by adjusting reactive power output of individual wind-turbine generators. Wind power plants with type 1 and 2 wind-turbine generators can control voltage by plant-level reactive compensation devices.

In order to prevent a reduction in system operating limits, VER projects should be expected to provide reactive power reserve services, particularly in voltage stability-limited systems. BPA has performed recent voltage stability studies that indicated potentially significant reductions in transfer capability on fully subscribed transmission paths if large VER projects connected to BPA's system displaced conventional local generation and were unable to provide reactive power reserves. Since reactive power reserves are deployed automatically in response to grid disturbances, VER projects should operate under Automatic Voltage Regulation. Technical methods need to be developed to verify, test, and monitor VER reactive power capabilities and voltage response characteristics. Monitoring equipment sampling rate needs to be several samples per second, because 4 to 6-second SCADA data rate is not adequate for dynamic response monitoring.

Question 10. To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?

BPA would support requiring all resources, including VERs, to be capable of providing frequency response if the resource could do so in a reliable and cost effective fashion. Frequency responsive reserve requirements have been suggested as a replacement for spinning reserve requirements, because frequency response reserves may reduce the amount of spinning reserves by improving the quality of the reserves. Frequency response requirements would need to address the quantity of frequency response required for an interconnection and the appropriate distribution and allocation of that response.

Frequency response requirements must encompass both the primary response time frame (how much response is needed to arrest system frequency excursion) and the secondary response time frame (how much response is required to sustain and how it needs to be distributed to avoid path overloads). The frequency response distribution and allocation is as important as the frequency response amount. A WECC frequency response reserve drafting team has identified uneven response distribution as a major reliability risk. Uneven response distribution can result in excessive power pickup on certain stability limited paths, which can lead to operation and reliability issues.

To develop frequency response reserve requirements, studies must be done to determine requirements for the entire interconnection to address both primary and secondary response time frames, sustainability, acceptable dead-band, and response rate (MW/0.1 Hz). Rules for response allocation and exchange must be developed as well. Frequency response reserve exchange must not adversely impact transfer capability. Finally, adequate monitoring infrastructure must be put in place as higher data resolution and time synchronization are needed for primary response verification.

To implement a frequency response reserve standard, a certain amount of on-line generating capacity in the interconnection must be capable of providing frequency response and generators must be distributed geographically to balance the response. Since generation patterns can be very diverse, arguably every resource on the system, including VERs, should be capable of providing frequency response. At any given time, only a portion of resources will be actually carrying frequency response reserves, and other resources may be operating at full power output, or baseloaded. In particular, VER frequency response will be needed during times such as the light load hours when the wind is at full output and many conventional frequency responsive units are offline. This frequency response requirement would be implemented by having the VERs hold their output below maximum available output when necessary to provide adequate headroom to respond to under-frequency conditions. The Commission should consider requiring all VERs to install the frequency responsive module for their control systems so as to be able to utilize it once the system has the need.

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

The Commission should apply reactive power requirements to VERs that are consistent with the requirements applied to other generation resources. Systems studies for some of the first facilities that interconnected to BPA's systems did not reveal the need for dynamic reactive power capabilities. However, operational experience shows several "unstable" large voltage fluctuations, and ultimately curtailment of the plant power output. Because of variability, it is not feasible to anticipate and study all possible combinations of VER generation levels, load levels, network conditions, and external generation patterns, but this makes it even more important that these projects have reactive power and voltage control capabilities.

Wind generation technologies have advanced significantly since 2003. Today, wind power plants regularly offer voltage control capabilities comparable to those of conventional generators. Wind power plants with type 3 and 4 turbines can control voltage by adjusting reactive power output of individual turbines. Many type 4 turbines have +/-0.9 power factor (dynamic) capability at the generator terminals, which typically translates into 0.95 dynamic power factor at the point of interconnection. Wind power plants with type 1 or 2 turbines can also control voltage with supplemental dynamic reactive compensation equipment at the project collector station. Therefore, voltage control is no longer a burden for wind power plants as it may have been with older turbines, and the voltage control requirement could be met independent of the particular turbine make or model.

Wind power plant developers have indicated that they favor consistent requirements to ensure that all of them are treated equitably and that their capital investments are more predictable. Application of a similar performance requirement for voltage control capability to both conventional generators and VERs would be equitable and provide predictability.

The relationship between dynamic and static reactive power requirements may require some attention with respect to VERs. One practical approach is to require +/-0.95 p.f. dynamic capability at the collector 34.5-kV bus, and allow static reactive resources to compensate for reactive losses between collector bus and point of interconnection. Such an approach aligns with operating practices when generator dynamic reserves are kept for response to grid disturbances.

Consistent voltage control and reactive power requirements is also beneficial in setting system operating limits on stability-limited paths. If all resources have very similar control capabilities, the system operating limit calculation is less dependent on what resource is generating at a given time. If some of the generators do not have voltage control capability, it will be necessary for the transmission provider to reduce the system operating limit, even if the path was already fully allocated. This places an additional burden on the transmission provider and would ultimately be detrimental to both the VER owner and power purchase customer. It also should be recognized that studies cannot predict every operational situation, particularly due to VER power output variability.

The Commission has allowed the developer to do its own studies and submit them to the transmission provider. BPA is concerned with potentially contradictory studies and the implications for interconnection requirements, because the developer may be unfamiliar with the nuances of the Northwest and WECC grids, and might make inconsistent study assumptions that significantly influence the results. Examples include appropriate seasonal resource dispatch and remedial action schemes.

BPA has had experiences where VER project developers make multiple changes to their project layout and electrical characteristics between submitting data during the interconnection study phase and energization. This data would include electrical parameters of the turbines and collector system equipment as well as reactive compensation equipment sizes and control settings. Use of smart grid technologies, such as synchro-phasors, needs to be encouraged for power plant model validation and analysis of control performance.

Voltage stability-limited systems rely on voltage controls provided by power plants. Power plants carry dynamic reactive power reserves that are automatically deployed during disturbances to maintain voltage stability. As long as VERs have to follow the same rules as other generators, there should not be an issue with reactive power requirements. The +/- 0.95 reactive range at the point of interconnection with an automatic voltage regulator should be sufficient. The automatic voltage regulator standard, which specifies that synchronized units are required, should be modified to include all generation.

BPA also sees the need for VERs to participate in secondary voltage control. In the Pacific Northwest, wind power plants tend to be clustered, with multiple plants located within short electrical distance from each other. The plants typically have a combination of owners and turbine technologies. Without coordination, the reactive power is not equally shared among the individual plants. In some cases, reactive power is circulating between two plants (one is bucking, while the other is boosting nearly the same amount of reactive power). Coordination of voltage schedules through secondary voltage control will ensure equitable reactive power sharing among the wind power plants, proper voltage schedule, and appropriate amount of dynamic reactive power reserves.

Plant operators should be prohibited from avoiding the intent of voltage control requirements through manipulation of control system settings. For example, use of an unreasonably large reactive droop or voltage dead-band setting to effectively block the plant's response to a voltage deviation should not be permitted.

F. Capacity Markets

The Pacific Northwest does not have a structured short-term or long-term capacity market, and BPA has successfully integrated a large amount of VERs up to this point without such a market. However, the general topic of how a balancing authority can effectively meet its capacity needs to ensure a reliable and cost-effective supply of power, while simultaneously ensuring it can accommodate the needs for large amounts of VER integration, is a critical and timely policy topic for the Commission to address. For that reason, BPA's comments in this section are directed to the broader topic of VERs and capacity needs of the power system. Previous sections of BPA's response describe how the balancing reserve capacity that a source balancing authority must hold could be reduced through intra-hour scheduling, dynamic scheduling or operational tools such as DSO 216. Those sections also describe challenges associated with these initiatives and some of the infrastructure changes required for implementation.

Since most of the wind generation in BPA's balancing authority is concentrated in a relatively small geographic region and does not generate consistently during extreme weather events, BPA’s actual operating experience shows that wind generation in BPA’s balancing authority cannot be relied on to add much, if any, dependable capacity. In addition, since much of the wind generation is exported to neighboring systems, it has added to rather than reduced the capacity needs of the BPA system. For both the source and sink balancing authorities, after accounting for operating reserves, balancing reserves, hour-to-hour and day-to-day or seasonal shaping to meet peak loads or supply wholesale market transactions, wind generation in BPA’s balancing authority requires at least an equal amount of capacity to back up their generation.

As discussed in Part II, the source balancing authority should not be considered the default supplier of balancing reserves for VER generation that is exported to serve load elsewhere. This is an inefficient use of balancing reserve capacity. BPA has estimated that when the source balancing authority carries balancing reserve capacity to firm the output of VERs through the scheduling hour, it needs incremental balancing reserves equivalent to approximately 33% of the nameplate capacity of wind in its balancing authority. Furthermore, since the sink balancing authority must maintain reserve capacity to serve its load for the next hour when scheduled output is reduced, splitting the obligation between source and sink balancing authorities with no clear definition of responsibilities requires greater total amounts of balancing reserve capacity.

A possible tool for reducing the source balancing authority’s balancing reserve capacity obligation is to not require the balancing authority to maintain the VER schedule through the entire scheduling period, if station control error exceeds a certain threshold. This can be accomplished with a reliability tool similar to BPA’s DSO 216, which would set limits on the amount of balancing reserve capacity the source balancing authority will provide. With this type of limitation, the VERs would be feathered more often when they are generating above their hourly schedule and the sink balancing authority would face curtailments of schedules with greater frequency, causing the sink balancing authority to meet its load during those curtailments by using the capacity it has developed for load service when the wind is not blowing.

As the amount of VERs increases, not only will additional transmission infrastructure be needed to integrate VERs, but other infrastructure and system improvements will also be needed. This infrastructure will include additional communication and control equipment to allow for dynamic transfers to export the balancing requirement to neighboring balancing authorities or enable self-supply options, adding flexible generation such as new thermal generation to provide additional incremental and decremental balancing reserve capacity, or adding storage capability such as pumped storage or battery storage.

VERs, such as wind power, also create operating challenges during light load hours when system loads are low. When BPA's hydro system is already at or near minimum generation during light load hours and large wind ramps occur, that currently can add up to 1,000 MW of wind generation during an hour. Due to such over generation, BPA already has found itself in a position where it has had to feather the output of the wind fleet to meet reliability requirements. In fact, this type of over generation condition is one of the most challenging issues currently facing BPA. As described in the additional comments below, BPA believes that the production incentives used to support renewable generation are exacerbating this problem.

BPA currently provides a large portion of its decremental balancing reserves for VERs in light load hours by using of its scarce fuel supply (water) to generate power during light load hours instead of storing such water for use in heavy load hours. BPA then has to purchase power from Northwest bilateral markets sourced primarily from thermal resources during heavy load hours to serve a portion of its load obligations.

BPA believes that there are basic principles that can help guide Commission policy to ensure that large amounts of VERs can be effectively integrated into the grid at lowest cost to consumers while also ensuring adequate capacity to maintain a reliable system:

- Rather than spend large amounts of capital to ensure that the full output of a large scale VER fleet can be absorbed by the power system for even very low probability events (tail events), some accommodation to allow for the VER power to go unused (not generated) by feathering should be allowed.

- A clear process or approach needs to be in place to specify which party(ies) are responsible for providing firm reliable capacity resources needed for the balancing reserve capacity to provide incremental or decremental generation to match the output of the fluctuating VER generation, with an equally important, commensurate commitment for who will pay for this capacity. This will ensure that appropriate planning is done and needed infrastructure additions are made to the system and that those costs are paid by entities that benefit from such services.

- Given the differing physical and institutional differences in the various power systems in the country, it is important to allow for varying solutions that can best meet the needs of individual regions. For example, given the nature of the vast hydro generating system in the Pacific Northwest, the need for regulation services is not as significant a challenge as in other parts of the country, but light load hour ramping problems with light load hour load and minimum hydro generation operating requirements can be a major challenge. Also, BPA and other regional entities have been pursuing several initiatives (*e.g.*, dynamic scheduling, intra-hourly scheduling, and self-supply) to ensure that flexibility from existing non-Federal generation within BPA's balancing authority and adjacent balancing authorities is available to help with VER integration. BPA believes this approach may allow BPA to integrate large amounts of additional VERs without having to incur the significant costs, challenges, controversy and time delays that would be associated with going to RTO-style capacity and energy markets.

Question 1. Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?

BPA has observed that the wind energy on its system tends to not operate when it is very cold or very hot, thus providing very little or no capacity when the system is facing its peak loads. For example, during a cold snap in January of 2009, the wind interconnected to BPA's system had virtually no output for an 11 day period. There is widespread, although not universal acknowledgement in the region that wind energy provides little to no peak capacity value to the system. Even if it can be demonstrated that there is a small quantity of peaking capacity value across a wider geographic footprint on a loss of load planning basis, this typically will not translate into tangible capacity value in the shorter-term time frame of daily and hourly operations. BPA acknowledges that there may be wind regimes in other parts of the country that demonstrate a higher correlation with periods of peak load and may result in some positive capacity value, but the question of whether any rating rules developed for a specific area are unduly discriminatory would best be addressed on a case-by-case basis in proceedings addressing the specific rule in question rather than through a broader rulemaking.

Question 2. Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?

The obligation for capacity resources to offer into the day-ahead market does not unduly discriminate against VERs. If resource sellers are actually capable of providing the capacity that is implied by their product definition (*e.g.*, firm WSPP Schedule C energy in the West), then those sellers should be able to sell into the day-ahead markets on a non-discriminatory basis. Must-offer provisions are not applicable to BPA's markets, so BPA does not have an express position on that topic. BPA believes that markets for capacity resources must be structured around the necessary time increments to make unit commitments to provide dependable capacity. VERs need to be combined with dispatchable resources to provide firm power. BPA does not believe that changing the design of day-ahead markets will fundamentally change the operational issues experienced in real-time operations with VERs, but the development of supporting products and services, as well as self-supply options and clear definitions of load service responsibility may facilitate increased participation by VERs in day-ahead markets.

Question 3. 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?

As described above, existing ancillary services do not adequately compensate source balancing authorities that are exporting large amounts of VERs. BPA established its wind balancing service to address this issue. If the *pro forma* Schedule 9 is interpreted to require the source balancing authority to firm delivery of hourly amounts of scheduled generation by accepting all amounts of generation imbalance energy, BPA believes that the issue of adequate compensation for use of reliability services exists regardless of VERs choosing to become capacity resources. It is imperative that the Commission clarify the respective obligations of the source and sink balancing authorities under Schedule 9 to enable cost recovery for the entity responsible for providing the balancing reserve capacity. Since VERs presently have no obligation to make long-term commitments to purchase generator imbalance service under Schedule 9, there is no guarantee that VERs will not choose another solution if a source balancing authority makes significant investments to support VER development, such as investments in balancing reserve capacity resources or enhancement of dynamic transfer capabilities. The Commission should give consideration to requiring forward control area service commitments from VERs that seek a service requiring the source balancing authority to provide additional balancing reserve capacity.

Question 4. 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?

The rapid increase of wind energy in the Pacific Northwest has demonstrated that traditional metrics for determining generation resource adequacy may need to be enhanced in order to address whether there is sufficient ramping flexibility in the system to reliably manage the incremental variability and uncertainty. Although the Pacific Northwest does not have an organized capacity market, the region is attempting to address these important issues through the resource adequacy forum at the Northwest Power and Conservation Council.

Additional Comments on Market Issues Associated with Marginal Production Incentives

The Federal Production Tax Credit and Renewable Energy Credits (RECs) are important pieces of Federal and state legislation that seek to address critical energy and environmental policy objectives. BPA offers the following comments as an experienced utility operator seeking durable solutions to the sustainable development of renewable energy in the United States, but cognizant of the day-to-day operational realities of VERs.

The electricity markets in the Pacific Northwest provide some good examples of the market issues caused by production based incentives. Production tax credits and state renewable portfolio standards that measure compliance as a percentage of energy load served create incentives for wind plants to run even when their operations conflict with reliability or environmental requirements. Furthermore, these incentives provide a monetary basis to run wind plants even when the plant owner must pay (negative market price) to sell energy in the wholesale markets up until that point at which the negative price exceeds the value of the production based credits.

There are at least two instances where running wind generators conflicts with operational objectives of the system. Under certain circumstances, wind generators cannot displace thermal generation because the thermal plants must still run to provide the balancing reserves to meet unexpected amounts of wind generation, or they may need to remain running to meet load ramps the next morning, because operators do not know if the VER will be generating during the morning load ramp.

In the other instance, the wind generators will run even if offered hydroelectric energy to displace their output at a zero price. In some hydro conditions, VER operation, paired with the balancing authority obligation to balance loads and resources, could force river operations that would, absent other actions by BPA, result in a violation of non-power constraints, such as limitations on the amounts of spilled hydroelectric energy to protect endangered salmon in the Columbia River. BPA discusses these non-power constraints and the negative impacts that VERs can have in the response to question five in section G.

System operators need the ability to dispatch VERs off the system to meet environmental and other statutory requirements, and balancing authorities with these types of requirements should not be required to compensate VERs for lost production incentives when such dispatch instructions are based on environmental or statutory requirements.

Additional Comments on "Open Season" Process for Determining Balancing Reserve Capacity Plans

BPA believes that an "open season" type process similar to what the Commission has allowed for transmission should be allowed for VER control area services. If, through the development of a balancing plan, a VER and the load serving entity purchasing the VER generation decide not to self supply or do not have a sink balancing authority capable of providing the service through dynamic transfer, the VER and load serving entity would request the amount of firm control area service they need from the source balancing authority and the start date for such service. These requests would be for commitments of at least two years and they could be longer-term if stranded costs and other risks can be addressed. Upon completion of studies and the source balancing authority determination that it could reasonably supply or expect to be able to acquire necessary third-party supply to provide such service, the balancing authority would offer binding firm service commitments. Even under this framework, the balancing authority is likely to need reliability and operational protocols such as DSO 216 to enforce the limitations on its capacity commitments, and to manage reliability during extreme tail events.

Additional Comments on Avista Rule and Acquiring Necessary Balancing Reserve Capacity at Market Based Rates

To increase the number of suppliers of ancillary services to accommodate the integration of VERs, BPA urges the Commission to reconsider its restriction on sellers with market-based ancillary service rate authority under the *Avista* rule from making "sales to a public utility that is purchasing ancillary services to satisfy its [OATT] requirements to offer ancillary services to its own customers."[30]

In Order 697, the Commission facilitated implementation of its general policy in *Avista* that "third party ancillary service sellers that cannot perform a market power study should be allowed to sell ancillary services at flexible rates," but maintained the position that the "approach will not apply to sales to a public utility who is purchasing ancillary services to satisfy its [OATT] requirements to offer ancillary services to its customers."[31] Although the Commission repeated that it is "open to considering requests for market-based rate authorization for such sales on a case-by-case basis,"[32] this does not seem to be occurring beyond a few isolated instances. BPA believes that the limitation is stifling the creation of competitive markets for ancillary services.

When considering Order 697, the Commission received many comments that the current approach to authorizing third-party sales of ancillary services at market-based rates has not

[30] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, 119 FERC ¶ 61,295, at P 1051 ("Order No. 697") (citing *Avista*, 87 FERC ¶ 61,223, at ¶ 61,883 n.12 (1999)).

[31] *Id* at P 1058, 1061; *see Avista*, 87 FERC ¶ 61,223, at 61,883 n.12.

[32] Order No. 697 at P 1061; *see also Avista*, 87 FERC ¶ 61,223, at 61,883 n.12.

successfully created robust markets.[33] Puget Sound Energy conducted a review of the dockets in which the Commission had granted market-based rate authority for ancillary services under the *Avista* rule and found that these sellers made only a handful of sales, whereas virtually all ancillary services outside of RTO or ISO markets were provided at cost-based rates by transmission providers.[34] In addition, when transmission providers have issued Request for Proposals ("RFPs") for ancillary services, which will probably be increasingly common to support integration of VERs, the transmission providers have received little to no bids.[35] Indeed, in *Northwestern*, one of the few instances in which the Commission has granted an exception to the prohibition on market sales to transmission providers purchasing ancillary services to fulfill their OATT obligations, Northwestern received only two workable responses to its RFP for Regulating Reserve Service.[36] In light of the need for increased ancillary services markets to promote the integration of VERs, BPA respectfully requests that the Commission find a way to facilitate sales of ancillary services by sellers with market-based rate authority to transmission providers seeking to fulfill their OATT obligations while also protecting consumers from market manipulation.

G. <u>Real-time Adjustments</u>

The variable nature of wind generation makes it difficult to predict output on an hour to hour basis. BPA balances the variability of wind generation using the FCRPS, but the FCRPS has its limits, as various environmental regulations create minimum generation conditions and constrain BPA's flexibility to maintain load and resource balance.

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[33] Order No. 697 at P 1053.

[34] *Id.* at P 1054.

[35] *See Dynergy*, 124 FERC ¶ 61,262, at P 11 (2008); *Northwestern*, 121 FERC ¶ 61,204, at P 6, 18-19 (2007).

[36] *Northwestern*, 121 FERC ¶ 61,204, at P 6.

Although existing curtailment and redispatch tools and processes have generally been adequate to manage line loading or system operating limits in real-time, the increasing number of VERs in BPA's balancing authority has made it necessary to adopt additional real-time tools and processes, namely DSO 216.[37] BPA believes that as the percentage of VERs increases in other balancing authorities, system operators will require similar operational and reliability protocols to control VER imbalances that impact reliable operation of the system.

Question 1. How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?

Although the increase in VERs in BPA's balancing authority area may create additional line loading on the transmission system, BPA believes that current curtailment and redispatch practices are generally sufficient for managing system operating limits. BPA expects to continue to follow curtailment and redispatch practices consistent with BPA's OATT when managing system operating limits in the near future.

As the number of VERs continues to increase, however, the potential for system operating limit violations due to VER scheduling error contribution also increases. Since any energy that is generated above scheduled quantities is not scheduled by the VER, system operating limits can only be managed through pro rata curtailment of schedules on a certain path. While pro rata curtailments according to transmission priority will allow BPA to manage system operating limit excursions and maintain reliability, other transmission users may be curtailed more frequently due to the difficulty of accurately scheduling VER generation. BPA will continue to monitor this issue over time to identify any implementation challenges or equity issues among transmission rights holders.

[37] *See* Part I, Section C, pp. 12-15.

In addition, to manage the BPA system during extreme VER variability events, BPA developed DSO 216 to maintain load and resource balance within the balancing authority area. DSO 216 gives BPA the ability to curtail wind generator schedules or limit wind generation when BPA has deployed almost all of its available balancing reserve capacity. The DSO 216 planned balancing reserve capacity limitations allow BPA to maintain enough balancing reserve capacity so that the variability of wind can be balanced with load 99.5% of the time. As the level of VER integration increases in other balancing authorities, system operators will likely need similar operational and reliability protocols to control the variability of VERs and maintain load and resource balance.

Question 2. Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?

BPA's existing redispatch and curtailment practices for managing system operating limits and line loading are based on BPA's OATT, and all resources are treated comparably based on transmission priority. BPA believes these existing practices do not unduly discriminate against VERs, and that additional specific controls, such as DSO 216, will be necessary to manage VER variability and maintain load and resource balance.

Question 3. Some RTOs/ISOs will redispatch VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?

This question is not applicable to system operators in the Pacific Northwest.

Question 4. Should transmission loading relief protocols be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs? If so, how? Similarly, should redispatch and curtailment protocols in non-RTOs/ISOs be revised to consider economic merit for all resources? If so, how?

BPA does not believe it is appropriate to consider resource economic merit when curtailing transmission service to reduce line-loading. Line-loading problems should be addressed by curtailing transmission service on a pro-rata basis by curtailment priority, as provided in the OATT, irrespective of the economic characteristics of the underlying generating resource.

BPA suggests that the Commission not require economic merit to be considered in managing line-loading or implementing curtailments, whether conducted by the reliability coordinator or the balancing authority. Currently in the Western Interconnection, the reliability coordinator does not implement transmission loading relief protocols. The Western Interconnection currently follows WECC Regional Reliability Standard IRO-STD-006-0 for Qualified Path Unscheduled Flow Relief. This standard is applicable to transmission operators, balancing authorities, and load serving entities. The replacement standard, WECC Regional Reliability Standard IRO-006-WECC-1, is currently pending approval before the Commission. It allows the reliability coordinator to either approve or deny the proposed curtailment by the transmission operator within five minutes. BPA believes, however, that this five minute window will not provide the reliability coordinator with sufficient time to consider economic merit in approving or denying the requested curtailments.

Curtailments based on economic merit would undermine the fundamental principles of transmission service under the *pro forma* tariff. If economic merit is considered for all transmission customers, customers that purchase firm transmission may be curtailed before customers that purchase non-firm transmission. If economic merit is only considered within transmission priorities, then curtailments will not be made on a pro rata basis, as currently required by the OATT, and higher cost resources will likely bear most of the curtailment burden. In both cases, consideration of economic merit translates into less reliable transmission service for customers with higher cost resources.

In addition, the difficulty in determining the economic merit of each resource makes such a concept unrealistic. It will be difficult to get any information on price for all resources, especially within the short time-frames in which curtailments must be implemented. Moreover, looking strictly at economic merit does not account for minimum generation and operation and other non-power constraints created by Federal statutes and regulations, which have a higher priority than economic merit.

Although BPA believes that current OATT provisions for least-cost redispatch of designated network resources are reasonable, the Commission should recognize that aside from resource costs, consideration should be given to non-power constraints. Since all designated network resources have the same curtailment priority, and network resources are redispatched on a pro rata basis with other firm transmission service, using least-cost for network integration transmission service redispatch does not undermine the fundamental principles of the OATT. Further, least-cost redispatch of designated network resources does not present the same challenges as determining economic merit for all resources, as customers must identify network resources and provide pricing information as a condition of receiving Network service. However, since the FCRPS makes up the bulk of the network resources in the BPA balancing authority area, BPA modified its OATT and currently redispatches only the FCRPS, distributing those costs to all transmission customers. In BPA's experience, redispatch events have been infrequent and costs have been very low in recent years.

The Commission should not require that resource economic merit be considered in managing line-loading or implementing curtailments, whether conducted by the reliability coordinator or the balancing authority. VERs should be treated on the same basis as all other resources for purposes of managing line loading and system operating limits.

Question 5. 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?

BPA's primary generation resource is the FCRPS. The variable nature of VERs affects operational issues that arise with the FCRPS during minimum generation events and increases the frequency of minimum generation events. The FCRPS has strict limits on water flows and the spill of water due to Clean Water Act and Endangered Species Act requirements, which create minimum generation conditions. Before significant VER integration, BPA faced periodic minimum generation events, primarily during light load hours in the spring period when mandated high hydro flows and limitations on the spill of water were approached. With the significant addition of VERs to BPA's system, BPA has experienced an increase in the frequency of minimum generation events and must continue to run the water through the hydro generators and generate electricity to avoid violating spill limits while maintaining flow requirements.

During these times of must run operations, BPA has implemented methodical marketing activities that involve displacement of other non-VER generators, such as thermals, without must run requirements. These non-VER generators purchase low cost energy from BPA to meet their load service needs and displace their own resources with the purchased power for long periods. This allows BPA to maintain load and resource balance and enables non-VER generators to meet their load obligation using low cost hydro generation, while saving the fuel costs and other operational costs that they would have faced by generating.

The increasing number of VERs, however, limits the ability to efficiently coordinate a minimum generation event between thermal resources and the FCRPS. In some cases, as VER penetration increases, load serving entities are forced to keep more thermal generation on line to address hour-to-hour swings in VER production. To provide both decremental and incremental balancing reserve capacity, a thermal resource must operate at its mid-range. This turns thermal resources into must run resources and reduces the pool of displaceable generation. Because of the short-term variability of the VERs, however, some thermal generators may lack the operational flexibility to be displaced on short notice or for short periods. Longer-term solutions such as intra-hour markets may mitigate some of these impacts since they will leverage the diversity in the spinning and non-spinning capacity of the regional market and allow utilities to purchase some quantity of their hour-to-hour balancing requirements from other market participants rather than relying exclusively on their own generating resources.

As stated above, with the significant increase of VERS interconnected to the system BPA has experienced an increase in the frequency of minimum generation events that reduce the flexibility of the FCRPS to manage load and resource balance. To provide incremental balancing reserve capacity, BPA must operate below full capacity in heavy load hours. This allows hydro generation to increase if VER generation is less than its scheduled amount, but it reduces system flexibility because it reduces the volume of water that can be moved when loads are present. Instead, water is pressed into shoulder periods and light load hours, raising the minimum generation level or triggering additional minimum generation events. This puts the system at greater risk of violating non-power constraints during times of minimum generation events. At times when the hydro system has very little flexibility, BPA must carefully determine the production levels that will meet flow requirements while not overly committing FCRPS generators that are often operating close to capacity.

More accurate generation forecasting and reduced scheduling error for VERs may help to mitigate these operational issues. Although there have been improvements in forecasting for VERs, the ability to predict the shape and timing of VER output is still limited. The difficulty in forecasting VER energy is then compounded by scheduling error. Scheduling error may persist for multiple hours, which presents challenges for operators, especially those of fuel-limited hydroelectric facilities with binding non-power constraints and specific daily flow targets. Since operators cannot anticipate the magnitude or duration of scheduling errors, operators must often make rushed decisions that often do not result in efficiency.

Enhancing balancing authority coordination to capture benefits of geographic diversity of VERs and load diversity also would reduce the amount of balancing reserves required to reliably integrate VERs. This would result in fewer curtailments during minimum generation conditions, as well as a reduced frequency of minimum generation events. BPA is also actively facilitating the development of self-supply options for BPA's customers, and some of these customers may attempt to purchase their decremental balancing capacity from thermal resources, thus relieving some of the minimum generation pressures on the Federal hydro system. During minimum generation conditions, however, VERs should still be subject to generation output reduction protocols when necessary. As further explained in question six below, VERs have the technical capability to respond to dispatch instructions, and BPA believes that as the level of VERs increase within a balancing authority, the system operator will require operational and reliability protocols to control VER output to maintain system reliability.

In BPA's experience, thermal resources have historically responded to economic signals to reduce generation levels and shut down. The increase in VERs and the variability of VERs creates new complexity in the resource portfolios of load serving entities that are still being studied. BPA does not have a policy position on offering incentives to conventional base-load resources, but a thorough examination of mechanisms to cost-effectively increase the flexibility of baseload resources might increase the depth of light load balancing markets and reduce the incidence of negative prices. This requires ensuring a level playing field in the market and ensuring that a system operator's own resources are not subject to different pricing rules or left with stranded costs. A system operator must be able to recover the cost of its resource if it is mandated to provide service. Broad socialization of such costs will hinder the innovation that will be needed to develop lower cost solutions.

Question 6. To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

VERs interconnected to the BPA system are required to respond to all dispatch instructions. BPA has automated DSO 216 dispatch orders through use of Supervisory Control and Data Acquisition ("SCADA') or ICCP systems because of the large number of wind plants in BPA's balancing authority area and the need to obtain generation reductions within a 10 minute timeframe. BPA issues dispatcher reliability directives either through automated electronic signaling to plant operations or via dispatch instructions posted on a website. Wind generators in particular have control systems (*i.e.*, wind farm management systems) with the capability to respond to dispatch instructions to reduce real power output, modify reactive output to follow voltage schedules, and increase generation if the wind generator is already limiting output. Some of the newer VERs have directly connected their wind farm management systems to the BPA SCADA electronic communications system to accept DSO 216 signals directly into their control systems (with plant supervision), while other wind generators manually respond to the BPA electronic signals. All plant control systems should be designed to respond automatically to dispatch directives due to the variable nature of VERs and the large number of independent facilities being installed.

In addition, the Commission should require VER plant control systems to include effective governor response to reduce real power output in response to an over-frequency excursion. The large amount of VER generation being connected to the BPA system requires that wind generators be able to respond to system events similar to other generation resources. As the total amount of VER generation increases, VERs must have this ability to help maintain the reliability of the transmission system.

Furthermore, the Commission should require VERs to participate in balancing authority coordinated and secondary voltage control. BPA describes the issues contributing to the need for secondary voltage control in response to question 11 of section E.

BPA is in the process of developing an automated secondary voltage control system for all generation for system-wide applications. Presently, secondary voltage control is issued by dispatch manually (*i.e.*, voltage setpoint adjustments are issued to each generation project via ICCP). Again, with the large number of wind projects connected and connecting in the future to the system, there is a need to automate secondary voltage set point changes. The Commission should require VERs to participate in such balancing authority automated control systems.

As explained above, the technology exists for VERs to respond to dispatch instructions. The Commission should require balancing authorities and VERs to integrate their control systems to interact with each other and automatically respond to the necessary requirements or signals.

Finally, in terms of incentives for VERs to respond to dispatch directives, BPA has adopted the Failure to Comply Penalty Charge of $1000/MWh to ensure that all generators, including VERs, comply with all BPA dispatch instructions. This penalty charge has worked well at incentivizing compliance with BPA reliability directives. As the level of VERs increases within a balancing authority area, BPA believes that system operators will need financial incentives such as penalty charges for non-compliance to ensure that generators follow all dispatch directives and to protect system reliability.

IV. CONCLUSION

BPA thanks the Commission for its efforts to address the complex issues involving the integration of VERs and appreciates the opportunity to provide comments. To the extent that the Commission identifies the need for revisions to the Commission's policies or procedures, BPA supports changes that reflect BPA's recommendations and that account for regional variations.

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Respectfully submitted,

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