UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Comments of the Public Power Council, Franklin County Public Utility District, PNGC Power, Northwest Requirements Utilities, and Western Montana Generation & Transmission Cooperative on the Commission's Notice of Inquiry

Executive Summary

The Pacific Northwest supports renewable generation and has enjoyed considerable success in integrating VERs over the last decade. Wind energy is by far the largest and best developed of the variable, renewable resources in this region. Because most wind generation in the Northwest is, or is planned to be, interconnected into the BPA Balancing Authority Area (BA), BPA's situation is a useful example of the problems and potential solutions for VER integration.

At a high penetration level, such as in the BPA BA, wind generation needs significant amounts of capacity reserves. Wind plants need dispatchable capacity to balance the moment-to-moment variations in their generation caused by fluctuations in their fuel supply. The amount of capacity needed depends on a number of factors, including the amount of wind generation to be balanced, its location, and the accuracy of the generation schedules. The fact that approximately 80% of the wind energy generated in BPA's BA is exported to other BAs creates additional issues. BPA is providing balancing capacity reserves for wind located in its BA, but placing the responsibility for balancing VER output on the host BA, when the energy sinks elsewhere, can create economic inequities and inefficiencies. Loads in the host BA will see costs shifted to them unless those costs are fully recovered from the VER generators.

There is no single solution to these issues, and Northwest utilities have begun to implement and test a portfolio of initiatives that are intended to lessen the capacity reserve burden on host BAs and to ensure that the allocation of costs are transparent and equitable. This portfolio may or may not contain solutions that will assist other BAs in other regions of the country. These initiatives include:

- The Area Control Error (ACE) Diversity Initiative (ADI), which is a voluntary, wide-area agreement among BAs in the West to share area control errors in order to reduce the amount of reserves carried and deployed;
- Dynamic scheduling, which allows the host and receiving BAs to transfer to the receiving BA the obligation to provide balancing capacity and thus provides a way for BA's to share the burden of providing balancing reserves for VERs;
- Permitting VERs to self-supply all or a portion of the balancing reserve needed for their generating plants. This is intended to reduce the reserve burden on the BA;
- Investments in equipment to gather meteorological data from around the BA in order to improve wind forecasting to reduce capacity reserve needs;
- Commercial practices or tariff revisions to permit wind generators and others to alter their schedules at the bottom of the delivery hour to correct scheduling errors; and
- Appropriate price signals, and the allocation of costs to the parties that cause them to be incurred or benefit from their incurrence. Assessment of integration costs makes evident the value of better scheduling, self-supply of reserves and capacity resource development and should drive the development of further solutions.

The Commission has correctly identified its obligation to eliminate undue preference and undue discrimination regarding the integration of VERs. The elimination of undue discrimination, however, does not require or permit the regulatory subsidization of any class of generators, nor does it require the elimination of all differential treatment. As the Commission addresses the questions that it has posed regarding the integration and market participation of VERs, it should not advantage VERs over other resources in markets or in system operations. This means that the integration costs and risks should be allocated to the parties that cause them to be incurred, or who benefit from their incurrence, and costs should be transparent and included in the delivered price of the VER power. The full cost of integration needs to be explicit and visible in the market so that utilities and merchants can make informed decisions about the development of both renewable and non-renewable generating resources.

The Commission should refrain from adopting national rules on VER integration. Most BAs are at early stages in the process of integrating VERs and do not yet have experience to determine what portfolio of solutions will benefit their efforts. Regions differ with regard to the renewable resources that they can develop, the markets available to participants, the nature and strength of the transmission system and the relative locations of resources and loads, and dispatchable resources available for use. Given the diversity of circumstances, there will be no one-size-fits-all solution for VER integration. Each region will have to make the best solutions that it can, given the assets they have available and that they can reasonably be expected to develop.

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On January 21, 2010, the Federal Energy Regulatory Commission (the Commission) published in this docket a Notice of Inquiry regarding the Integration of Variable Energy Resources (VERs). The Public Power Council (PPC) files these comments, on its own behalf and on behalf of Franklin County PUD, PNGC Power (on its own behalf and for its members), Northwest Requirements Utilities (NRU) and Western Montana Generation & Transmission Coop. (WMG&T), pursuant to the Commission's Federal Register notice of January 27, 2010,[1] and the Commission's Notice of March 3, 2010, extending the filing date for comments.[2]

Interests of PPC, Franklin County PUD, NRU, PNGC Power and WMG&T in this Rulemaking

The Public Power Council (PPC) is a non-profit trade association that represents the common interests of more than 100 consumer-owned electric utilities in the Pacific Northwest that are requirements power and transmission customers of the Bonneville

[1] Notice of Inquiry, *Integration of Variable Energy Resources*, RM10-11-000, 75 Fed. Reg. 4316 (Jan. 27, 2010).
[2] Notice Extending Comment Period, *Integration of Variable Energy Resources*, RM10-11-000, (Mar. 3, 2010).

Power Administration (BPA). PPC's members are located and serve retail customers in Washington, Oregon, Idaho, Montana and Nevada. In addition to purchasing wholesale power from BPA, many PPC member utilities either purchase non-federal wholesale power or generate power with their own renewable and non-renewable resources. Many more are expected do so over the next several years. Directly or indirectly, PPC members purchase power from, and in some cases are developers of, VERs.

Franklin County PUD is an electric utility located in Pasco, Washington, and purchases power from BPA and other sources. NRU is a trade organization representing Northwest consumer-owned utilities. PNGC Power is a generating and transmission cooperative, whose members are Northwest rural electric distribution cooperatives.[3] Similarly, WMG&T is a generation and transmission cooperative, whose members are Montana electric cooperatives. Many of the utilities represented by these three parties and Franklin County PUD are PPC members. All of these utilities are similarly situated to, and have similar interests as, the PPC member utilities described in the preceding paragraph.

Communications

PPC and the other parties request that service in this proceeding be made upon, and communications directed to, the following persons:

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[3] PNGC Power's member utilities are Blachly-Lane Elec. Coop., Central Elec. Coop., Inc., Clearwater Power Co., Consumers Power Inc., Coos-Curry Elec. Coop., Inc., Douglas Elec. Coop., Fall River Rural Elec. Coop., Inc., Lane Elec. Coop., Inc., Lincoln Electric Coop. (MT), Lost River Elec. Coop., Northern Lights, Inc., Okanogan County Elec. Coop., Inc., Raft River Rural Elec. Coop., Inc., Salmon River Electric Coop., Umatilla Elec. Coop., West Oregon Elec. Coop., Inc.

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Comments

A. General Comments

1. The Northwest has gained extensive experience over the last several years with integrating wind energy.

The Pacific Northwest supports renewable generation and has enjoyed considerable success in integrating VERs over the last decade.[4] Currently, the Northwest has approximately 4000 MW of installed wind capacity and expects this amount to rise to approximately 5000 MW by year's end.[5] For example, projects to explore wave energy projects[6] are underway, and we expect that the first utility-scale solar project in the Northwest will be energized in the fall of 2010.[7]

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[4] The first utility-size wind project in the Northwest, the 25-MW Vansycle wind project, was interconnected in 1998 by BPA. BPA, *Generation Inputs Study & Documentation*, WP-10-FS-BPA-08, Table 2.1, p. 99 (July 2009); BPA, *Market Price Forecast Study Documentation*, WP-10-FS-BPA-03A, Table 14, p. 53 (July 2009)(both available on BPA's website at http://www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/wp-10.cfm).

[5] See J. King, *Pacific Northwest Wind Power Development Activity*, p. 3 (Jan. 6. 2010), available at http://www.nwpcc.org/energy/Wind/meetings/2010/01/Default.htm.

[6] See http://www.oceanpowertechnologies.com/reedsport.htm.

[7] A 5-MW solar project is scheduled to be on-line in the early fall of 2010 in Christmas Valley, Ore.

Wind energy, however, is by far the largest and best developed of the variable, renewable resources in the Pacific Northwest. Because most wind generation in the Northwest is, or is planned to be, interconnected into the BPA Balancing Authority Area (BA), BPA's situation is a useful example of the problems and potential solutions for VER integration. As of January 13, 2010, BPA had 2780 MW of installed wind generation interconnected into its BA.[8] In its last rate case, BPA forecast that wind generation integrated into its BA by the end of FY 2010 would total 3198 MW.[9] By the end of FY 2016, BPA expects to have integrated more than 10,000 MW of wind generation.[10]

2. Success in Integrating VERs Creates Challenges for the Power System

At high penetration levels,[11] the integration of VERs into power systems can be challenging. By nature, VERs are not fully dispatchable because their fuel source cannot be controlled. Power systems integrating VERs, therefore, need dispatchable generation to increase and decrease their output to follow changes in VER generation over all timeframes. Not only must this generation be dispatchable, the dispatchable fleet must be flexible enough to move continuously or frequently within the delivery hour so that the fleet produces the power needed to balance the VERs' output.

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[8] BPA periodically updates the installed wind generation in its BA. As of the drafting of these comments, 2,780 MW was the current total installed MWs. See BPA's website at http://www.bpa.gov/corporate/WindPower/.

[9] See n. 4 *supra*, BPA, *Generation Inputs Study*, WP-10-FS-BPA-08, Table 2.4, p. 104 (July 2010).

[10] BPA's current forecast is available on BPA's website at http://www.bpa.gov/corporate/WindPower/.

[11] The penetration level of a type of resource is the area's average system peak divided by the aggregate energy produced by that type of resource expressed as a percentage.

BPA's experience with integrating wind generation illuminates VERs' needs for dispatchable capacity. In calculating and pricing wind generation's within-hour capacity reserve needs, BPA has identified three distinct components of capacity provided by the major federal hydro-electric units in the Columbia River basin: regulation, load-following capacity and imbalance capacity.[12] BPA calculated the use of these three reserves to balance wind generation in the BPA BA. The amount of balancing reserves required varies by the amount of installed capacity of the wind fleet, the accuracy with which wind plants schedule their output and the correlation in ramps between and among wind generators in the fleet.[13] In BPA's BA the ramps in wind generation can be very significant and are not correlated with load movement.[14]

Wind generation needs significant amounts of balancing reserves. In its most recent rate case, BPA determined that to balance 2111 MW of wind generation, if the

[12] As used in these comments, "regulation" refers to the power capacity of units on automatic generation control collectively moving continuously to match load and generation within the delivery hour. "Load-following reserve" is power capacity from units that are spinning and not spinning being deployed 10-60 minute increments to match load and generation within the delivery hour. Lastly, "imbalance capacity" refers the changes in the load-following reserve as a result of differences between the scheduled and actual VER output across the integrated hour. For a general discussion of the balancing reserve and its use by VERS see BPA, *Generation Inputs Study*, at n. 4 *supra*, § 2.1.2, p. 5-9.

[13] *Id*. Of the wind generation in BPA's BA, the great majority is concentrated in the eastern end of the Columbia Gorge. Close proximity of wind plants to each other increases the correlation of their ramping behavior and increases the size of the ramps and the amounts of balancing capacity needed. See BPA, Map of Existing and Planned Wind Plants, at http://www.bpa.gov/corporate/WindPower/.

[14] See BPA website, links nos. 10 & 11 at http://www.transmission.bpa.gov/business/operations/wind/default.aspx.

wind generation schedules at a 30-minute persistence scheduling accuracy,[15] BPA would need to use 330 MW of incremental balancing (Inc'ing) reserves and 478 MW of decremental balancing (Dec'ing) reserves.[16] If the wind fleet schedules less well, at an accuracy equivalent to 45-minutes persistence scheduling, the amounts of balancing reserves needed increase to 408 MW of Inc'ing reserves and 600 MW of Dec'ing reserves.[17] The difference between the amounts of Inc'ing and Dec'ing reserves for 30- and 45-minutes persistence schedule accuracy roughly reflects the different amounts of imbalance capacity reserve needed by the wind generation at those scheduling accuracies.

[15] "Persistence schedule accuracy" is a measure of a wind generator's accuracy of scheduling the output of the plant. A persistence model is a simple forecasting tool that bases the forecast of a wind generator output for the delivery hour on the level of the generator's observed generator's output in a current or previous time period, for example 30, 45 or 2 hours prior to the start of the delivery hour. As a general matter, persistence schedules whose accuracy is equivalent to a 30-minute persistence schedule more closely match actual output than schedules based on 45-minutes or 60 minutes persistence, for example. The actual differential between schedules and wind generator can be analyzed and compared to what the generator's schedules would have been under different persistence scheduling timeframes and are thus measured for their accuracy. This is one measure of schedule accuracy.

[16] See n. 4 *supra*, BPA, *Generation Inputs Study*, WP-10-FS-BPA-08, Table 2.5, p. 105, line 3, col. K & L.

[17] *Id*., at Table 2.8, p. 108, Col. K & L. At a scheduling accuracy equivalent to 2-hours persistence, the Inc'ing reserves for 2655 MW of installed wind capacity would be 682 MW and Dec'ing reserves would be 979 MW. See also, BPA, *Generation Inputs Study and Study Documentation,* WP-10-E-BPA-08, p. 46, Table 2.12, Col. K & L (Feb. 2009) (available at BPA's website at https://secure.bpa.gov/RateCase/Documents.aspx?ID=17). Table 2.12 also gives Inc'ing and Dec'ing reserve amounts for 2655 MW of installed wind capacity scheduling at the accuracy equivalent of 30-, 45- and 60- minutes persistence.

The problem of providing capacity reserves is exacerbated in BPA's situation by the fact that the majority of the wind plants are concentrated in an area around the Columbia Gorge in Washington and Oregon. The close physical proximity of the plants increases the correlation between their generation output and increases the size of wind fleet generation ramps. BPA must plan to meet these ramps with balancing capacity that it must set aside on its system.

The fact that approximately 80% of the wind energy generated in BPA's BA is exported to other BAs creates additional issues.[18] Placing the responsibility for balancing VER output on the host BA, when the energy sinks elsewhere, can create economic inequities and inefficiencies. Loads in the host BA will see costs shifted to them unless those costs are fully recovered from the VER generators. There is no single solution to these issues, and Northwest utilities have begun to implement and test a package of reforms that are intended to lessen the capacity reserve burden on host BAs and to ensure that the allocation of costs are transparent and equitable.

3. The Northwest is Developing Market and Operational Solutions to these Challenges

Northwest utilities have been working together for several years to meet the challenges posed by high penetration levels of wind energy.[19] A number of initiatives have come out of these discussions that may help to manage the integration of

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[18] BPA, *Administrator's Final Record of Decision*, § 20.2, p. P-1 (July 2009) (available on BPA's website at http://www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/wp-10.cfm).

[19] See Wind Integration Forum, *The Northwest Wind Integration Action Plan*, WIF Doc. 2007-1 (Mar. 2007) (http://www.nwpcc.org/energy/Wind/library/2007-1.htm).

Northwest wind energy. Each of these initiatives is important in right, but no single initiative can solve the larger problems. Moreover, these initiatives are intended to address problems faced by utilities in the Northwest and the West more broadly; they may or may not be solutions that will assist other BAs in other regions of the country.

a. The ADI Project

The Area Control Error (ACE) Diversity Initiative (ADI) is a voluntary, wide-area agreement among BAs in the West to share area control errors in order to reduce the amount of reserves carried and deployed. Currently, the following eleven BAs have executed ADI agreements and are operating under them: British Columbia Transmission Corp. (also the ADI host), PacifiCorp (East), PacifiCorp (West), Seattle City Light, Northwestern Energy, Idaho Power Co., NaturEner, Public Service Co. of Colorado, Salt River Project, Arizona Public Service and BPA.[20] As ADI gets more BA participation and more data can be collected we will have a better understanding of the magnitude and value of the savings produced.

b. Dynamic Scheduling and Self-Supply of Balancing Reserves

Use of dynamic scheduling to deliver variable generation to an interchange point allows the host and receiving BAs to transfer to the receiving BA the obligation to provide balancing capacity and thus provides a way for BA's to share the burden of providing balancing reserves for VERs. BPA recently completed a study of its

[20] In addition the following utilities have executed ADI agreements but have not yet begun operating within them: El Paso Electric, Public Service Co. of New Mexico, Tucson Electric, Puget Sound Energy, Nevada Power and Sierra Pacific Power Co.

transmission network and Southern Intertie to California to determine how much dynamic scheduling can safely be permitted on those parts of the transmission system. The results indicate that a limited amount of dynamic transfer capability is available on the network and Southern Intertie.[21] California and Northwest parties, however, have begun discussions regarding potential expansion of the Intertie, which we hope would increase the amount of dynamic transfer capability between the regions.

Another way for BAs to share the balancing reserve burden is to permit VERs to self-supply all or a portion of the balancing reserve needed for their generating plants. As a pilot project, BPA will permit at least one wind generator to undertake self-supply of a portion of the balancing reserves needed by its wind plants in FY 2011.

c. Initiatives to Improve Schedule Accuracy and Mitigate the Impact of Inaccuracies

Initiatives are being undertaken by BAs to permit wind generation and transmission system users to lower their use of balancing energy and capacity use. BPA has made investments in the last year in equipment to gather meteorological data from around the BA in order to improve wind forecasting. Better prediction of the timing and magnitude of wind ramp events should allow wind generators to produce better near-term generation forecasts for upcoming delivery hours.

Pursuant to the work of a joint initiative by ColumbiaGrid, Northern Tier Transmission Group and WestConnect, a number of Northwest transmission providers

[21] The Southern Intertie is comprised of transmission facilities interconnecting the Pacific Northwest and California. The results of the study are summarized at http://www.transmission.bpa.gov/wind/dynamic_transfer/default.cfm.

and BAs[22] have adopted commercial practices or tariff revisions to permit wind generators and others to alter their schedules at the bottom of the delivery hour to correct scheduling errors. These pilot projects should permit wind generators to consume less imbalance capacity; the extent to which these will permit BAs to carry fewer balancing capacity reserves, chiefly imbalance capacity reserves, on a planning basis or for a delivery hour has yet to be demonstrated.

d. Appropriate Price Signals

Lastly, BAs are identifying and quantifying the costs of VER integration and are taking steps to assign those costs to the parties that cause them to be incurred or benefit from their incurrence.[23] Identification and appropriate recovery of these costs is important both for equity and to establish correct economic signals to the market. Perhaps the most significant impetus for several of the Northwest's recent initiatives was provided by BPA's establishment of a rate to recover the costs of balancing reserves needed by wind plants within the delivery hour. By quantifying the current consumption of capacity products and forecasting future use by an increasing amount of

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[22] These transmission providers include PacifiCorp, Puget Sound Energy and Avista, which jointly filed amendments to that OATTs, and BPA (as a pilot for wind generators only). Grant County PUD, Seattle City Light, Tacoma Power and Chelan County PUD are balancing authorities participating in processing e-tags on a mid-hour basis. For a more detailed summary see "Think-Tank Intra-Hour" presentation, Mar. 4, 2010, p. 5-6, available on the ColumbiaGrid website at http://www.columbiagrid.org/ji-tt-documents.cfm.

[23] *See e.g.*, Pet. of Idaho Power Co., *In the Matter of Idaho Power Company's Petition to Increase the Published Rate Eligibility Cap for Wind Powered Small power Production Facilities; and To Eliminate the 90%/110% Performance Band for Wind Powered Small Power Production Facilities*, Idaho PUC Case No. IPC- 07-03, Feb. 6 2007 (parties subsequently settled).

installed wind generation capacity, BPA clearly revealed the magnitude and causes of the balancing reserve use and placed a value on the balancing reserve components. This has made the value of better scheduling, self-supply of reserves and capacity resource development more evident and understood and should drive the development of further solutions.

4. Overall Policy Direction

a. The Commission Should Not Take Actions that Bias the Generation Market

The Commission has rightly identified its obligation to eliminate undue preference and discrimination regarding the integration of VERs. The elimination of undue discrimination, however, does not require the regulatory subsidization of any class of generators, nor does it require the elimination of all differential treatment. VER generation does not provide capacity to the power system but requires system capacity for within-hour balancing to meet schedules. Asynchronous variable generation also cannot produce reactive power without additional equipment. It is not discriminatory to recognize these differences and account for them in tariffs, rates and interconnection requirements. As the Commission addresses the questions that it has posed regarding the integration and market participation of VERs, it should not advantage VERs over other resources in markets or in system operations. The operational and economic relationships between VERs and dispatchable generation must be equitable; if they are not equitable, they will not be durable, and therefore will be to no one's advantage.

Cost-causation is the touchstone of equity in ratemaking. Costs and risks should be allocated to beneficiaries and to those that cause costs to be incurred. The first location at which costs will be incurred for these solutions is the BA, yet the BA and the loads in the BA may not be the entities that purchase the output of the VERs. Rather, much of the output of VERs in a BA may be exported out of the BA and perhaps out of the BA's region; this is the case in BPA BA, where approximately 80% of the output of wind generation in the BA is exported.[24] Utilities located outside of the VER's host BA, should bear the costs of importing those resources into their sink BA or region. Such costs include balancing reserve and transmission costs.

Once costs are appropriately allocated, the Commission needs to allow the economics to drive the development of generation resources; the delivered power cost of VERs must reflect the all-in cost of generation, integration and transmission or the Commission will bias the market towards those resources and away from potentially more efficient choices, such as conservation, distributed generation and other answers to the environmental drivers of federal policy. The full cost of integration needs to be explicit and visible in the market so that utilities and merchants can make informed decisions about the development of both renewable and non-renewable generating resources.

It is, of course, the case that within their respective jurisdictions, Congress and the states have established the level and type of support needed to establish the

[24] *See* n. 18 *supra*.

demand for renewable resources and the appropriate support needed to reduce their marginal cost. Washington State and Oregon each have Renewable Portfolio Standards (RPSs), as do California and other states in the Western Interconnection. These RPSs can be met by a variety of renewable resources, some of which are variable while others are not. Renewable resources also typically receive federal financial support through tax credits, either the Production Tax Credit or Investment Tax Credit. Together, these federal and state supports drive the market for new, renewable resource development generally. Development of particular resources, however, should depend on the total delivered cost of the resource, including balancing services, transmission and other costs. RPSs and existing federal and state financial and tax subsidies will inform those delivered power costs but the Commission should not play a role in further affecting the economics of those choices, other than to implement appropriate rates and cost allocation based on cost-causation.

b. The Commission Should Refrain from Adopting National Rules as Regional Differences in Renewable Resources, Markets and Transmission System Characteristics Are Significant

VERs present different challenges to different BAs and regions and there is no "one-size-fits-all" solution. For example, similar wind generation penetration levels will affect different regions and BAs differently. The affects, and therefore the solutions, will be driven by a variety of factors, including the characteristics of power markets, amounts and characteristics of dispatchable resources, the size of the renewable resources (fuel supply), the amounts and geographical dispersion of VERs using a particular fuel and the strength and topology of the transmission system. Regions will have to make the best solutions that they can given the assets they have available and that they can reasonably be expected to develop. This is a period where utilities and regions are still gaining experience and gathering information. PPC urges the Commission not to be prescriptive. If rules are adopted, they need to be flexible to permit sub-regions and individual BAs to craft solutions that best fit their needs and abilities. Currently, only a few regions have significant wind generation penetration levels and they are developing and testing solutions that are likely to work for them. They may not be adaptable to all regions.

B. Comments on the Commission's Questions in the Notice of Inquiry

PPC offers the following comments to the general topics and particular questions posed by the Commission. Where PPC has not responded to a particular paragraph or question, PPC does not have comments at this time.

1. Data, Forecasting and Reporting Requirements

a. Better Meteorological Forecasting is Needed

Accurate weather forecasting is important for managing wind generation and other VER generation in a BA. Accurate weather forecasting should help BAs and generators to predict, with a finite level of accuracy, the generation that may occur within the day and the delivery hour.[25] There is a distinction to be made, however,

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[25] In the Northwest, the principal focus of weather forecasting for this purpose is predicting the strength and timing of weather fronts that move through a region that has wind generation.

regarding the purpose of forecasting done by the BA and by the generator. BAs forecast generation ramps and aggregate generation output in order to determine needed balancing reserve levels over some timeframe to meet load and protect system stability. A generator forecasts its plant's generation output in order to make deliveries required by contracts or to markets. For each party the motivations and needs for weather forecasting are different, although their need for accuracy is common.

Weather forecasting practices related to temperature and load is quite advanced. However, current weather forecasting practices and, more importantly, the translation of weather forecasts into VERs' generation forecasts, seem inadequate. Better weather forecasting will provide generators with additional information that they may not have in making their generation schedules. It would provide BAs with tools to evaluate forecasts coming in from individual generators and may assist the BA in setting up its system to anticipate ramps on its system from multiple plants located in a given geographic region.

b. VERs Have an Integral Role to Play in Data Collection for Forecasting

VER generation plants should be a primary source of forecasting information. Wind plants, for example, have meteorological collection towers in and around their plants and collect the data for their own use. Other sources of data can be utilized, such as airport meteorological stations and other data collection sites.

PPC understands that there are active efforts to determine who should receive that information and generate forecasts. One alternative is that generators would have an obligation to make and report meteorological data in real-time from their plants to the BA. BAs would then take that data and data from other sources to develop hour-by-hour forecasts (or contract with a third party to do so). An alternative is to require VER generation to report that data to the National Weather Service or the National Oceanic and Atmospheric Administration.[26] Those organizations have established expertise in developing weather forecasts and could develop the expertise regarding wind forecasts and then provide hour-by-hour meteorological forecasts to the public and industry.

c. Better Weather Forecasting Must Translate into Better Generation Forecasts and Schedules

Better weather forecasting should permit VER generators to more accurately forecast and schedule their plant output. These generation forecasts and schedules inform the actions taken by the BAs in setting up their power systems to meet generation ramps. Because each wind generator is best able to predict its plant's output, generators should bear the risk of generation forecasting inaccuracy; much of the hourly forecast accuracy depends on their sophistication and motivation. Particularly in areas of complex terrain, actual output of wind generation is affected by local terrain and micro-climate. Generators will have much better and more extensive information as to the performance of their plants under various conditions. Moreover, generation scheduling accuracy will vary from plant to plant and plant operator to plant operator; the Balancing Authority cannot take the risk without either spreading the

[26] VERs should still be required to provide their outage information and schedules to the BA.

costs of error to all users of the system or to all VER operators. Either result would be unfair and remove incentives for generators to produce the best available forecast.

Over time, better generation forecasting should allow VER generators to reduce their imbalance capacity needs substantially. Once better accuracy is consistently demonstrated, more accurate generation schedules would reduce the amount of balancing reserve that the BA sets aside to balance VER generation over the course of an integrated hour. The question will be the extent to which better forecasting permits BAs to carry less *imbalance* capacity reserve on a forecast basis with a high degree of confidence. It should also be noted that greater scheduling accuracy will not significantly affect the amounts of regulation and load following reserves needed to balance the native variability of wind generation.

Ultimately, a forcing mechanism of some type is needed to ensure that best practices are consistently and competently implemented. Whether this is best achieved by monetary penalties, after-the-fact cost assessments, operational curtailments or some other mechanism is an open question.

With regard to the Commission's questions in paragraph 17 of the Notice, PPC provides the following comments:

> 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*?

Generally in the Northwest, each VER forecasts its own output and the sophistication of that forecasting varies but accurate prediction of the timing, and often the magnitude of, ramps within a day has been a challenge. BPA is beginning to forecast ramps but the ability to accurately translate these forecasts into generation forecasts has not been demonstrated.

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*?

Money is needed for new data gathering, communication infrastructure, expertise and forecasting software. The National Weather Service should be utilized but not duplicated. Overall, the needs of different regions for different forecasting services should be noted and taken into account.

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*?

In planning for generation ramps, system operators need information as to the timing of the ramp and its severity. This will necessitate weather forecasts throughout the delivery day and for one or more days prior to the delivery day.

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*?

VERs should be required to supply the same outage and output information as any other generating plant. Additionally, VERs should be required to collect and transmit as it becomes available all available meteorological data from their met stations on an instantaneous or near-real-time basis to the BA and/or NOAA. The BA should be allowed some discretion in outlining the type of data that is most useful to it.

> 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*?

Both centralized and decentralized forecasts will assist BAs to set aside or obtain the amount of reserves needed to balance wind output. In the end, however, the risk that generation output schedules are inaccurate must remain with the generators.

2. Scheduling Practices, Accuracy and Incentives for Accurate Scheduling

a. Scheduling Flexibility

As noted above, generation scheduling inaccuracy causes balancing reserves to be set aside and deployed on the power system, which in turn creates capacity and energy costs that must be recovered. Although not all of VERs' capacity reserve and energy needs can be eliminated, those needs should be reduced to the extent that the commitment and deployment of capacity and energy can be reduced without reliability risks and additional costs.

BPA and others in the Northwest are adopting business practices to permit wind generation (and in some systems load and other generation) to schedule at mid-hour.[27] Mid-hour scheduling should permit wind generators to reduce the amount of imbalance

[27] The current limitations are largely due to the impact on transmission provider and BA scheduling operations, as the changes are implemented by manual inputs, and desire to test effectiveness and usage.

energy they take from the system. PPC expects that mid-hour scheduling also should reduce the amount of imbalance *capacity* reserve set aside for wind generation to the extent the balancing reserve levels can reflect the assumption that mid-hour schedules will correct imbalances over an integrated hour. To be successful, mid-hour schedule corrections must reduce the energy and capacity reserves held by the power system, not just costs currently assigned to VERs. If the system continues to incur costs, but the VERs do not reimburse the system for those costs, the costs will simply be spread to other system users.

PPC believes that mid-hour scheduling is an important part of the package of initiatives being implemented in the Northwest. More empirical information and testing will be needed to determine its efficacy in the Northwest. With that background, the Commission should recognize that mid-hour scheduling is only one part of a package of reforms available to BA to address balancing capacity needs and BAs should be allowed to determine which reforms are most effective for its needs.

With regard to the Commission's questions in paragraph 22 of the Notice:

> 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*?

As noted above, the use of mid-hour scheduling intervals is being tested in the Northwest, but we have no data on which to base opinions. While theoretically promising and worthy of investigation, there will need to be some mechanism to require or encourage plants to make such corrections at mid-hour in each hour so that the BA can rely on the changes to reduce capacity commitment. The use of mid-hour scheduling changes should reduce the amount of imbalance capacity set aside in the system on a forecast basis. It seems unlikely that following reserves and regulation to follow the native variability of VERs' generation output would be much affected.

b. Scheduling Incentives

Overall, some form of incentive is needed to drive greater attention to generation forecast accuracy. BPA found that many wind generators did not pay attention to schedules until capacity reserve costs were passed through to them and penalties[28] for poor scheduling were imposed on them.[29] BPA has demonstrated that a considerable amount of imbalance capacity reserves can be required to meet inaccurate schedules. The costs of setting aside and deploying system capacity to meet those needs are significant and, if not recovered from the generators, they are passed on to other power customers. BPA's experience indicates that, to their credit, once generators understand the level and source of the costs, they are willing to make improvements and find ways to reduce their impact on the power system.

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[28] BPA adopted penalties for both generation and load that are imposed if actual generation or load deviates significantly from the schedule for more than three consecutive hours. BPA, *Administrator's Final Record of Decision*, § 20.2, p. 482-500 (July 2009) (available on BPA's website at http://www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/wp-10.cfm).

[29] *Id*. at P-3 ("[A]s wind has grown on our system, it has become clear that the lenient policy with little cost to scheduling inaccuracy has led, not surprisingly, to rather indiscriminate use of balancing services even when within the control of wind operators. The policies we are putting in place have already begun to alter this behavior.")

With regard to the Commission's questions in paragraph 25 of the Notice:

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*?

Although use of the third-tier of imbalance energy penalties might provide some limited incentive to VERs to reduce their imbalances, it is unlikely to significantly affect VER scheduling accuracy. Moreover, these energy charges will not provide an accurate or adequate price signal with regard to capacity commitment and usage. Accurate price signals and charges for capacity needed to balance the generation would provide better incentives to schedule accurately.

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?*

Assigning the capacity reserve costs to VERs would provide a fair and probably an adequate incentive. Improvement in forecasting and scheduling requires an investment in technology and expertise. Exposing VERs to the capacity costs is a better price signal and incentive.

3. Forward Market Structure and Reliability Commitment Process

a. Day-ahead Market Participation

Each organized market has different rules. As a result each will have to be considered individually. The rules, however, should be carefully crafted to ensure that VERs do not gain unduly preferential treatment. Thus, if a VER generator is allowed to participate in a day-ahead market, it should not have participation rights that are more advantageous than those given to other, non-VER, generators.

b. Reliability Commitments

With regard to the Commission's questions in paragraph 31 of the Notice, PPC does not have comments at this time.

4. Balancing Authority Area Coordination and Consolidation

Whether or not it is economically advantageous or efficient for BAs to coordinate or consolidate depends entirely on the characteristics of the BA and the BA(s) with which it might form a relationship. The advantages and disadvantages of BA coordination or consolidation hinge on a number of factors, including the level of VERs penetration in the BA and the ability of the BA to procure and deploy balancing capacity. The ramping capability of the BA's resources, the VERs penetration level in the BAs, the locations and types of VERs present, the ability to wheel the wind power out of the BA (either flat or on a dynamic schedule), and other characteristics will dictate whether consolidation or coordination is needed or useful. Each BA's forecasts of its own resource acquisitions and the level of future VERs penetration must also be accounted for. For example, geographic diversity of VERs can be beneficial in that the generation ramps may be reduced or offset by widely dispersed generating plants. Ability to capture the diversity, however, depends on the amount of excess transmission capacity between the various VERs locations and the loads that they serve, and whether BAs have that capability is entirely dependent on individual circumstances.

PPC encourages the Commission to let the BAs take the lead in determining the best course of action for their individual situations. At this stage of VERs development in most BAs, it is too early to prescribe solutions or actions. BA operators will make decisions based on the reliability needs of their systems, the economics, and the opportunities presented to them by their neighboring systems. The record does not support the creation by rulemaking of regulatory incentives to consolidation or coordination, or disincentives to BA operation.

With regard to the Commission's questions in paragraph 33 of the Notice, :

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

The electrical or geographic size of the BA alone does not dictate the costs of integrating VERs. The level of VER penetration in that BA and the availability of dispatchable resources with appropriate ramping capabilities also drive integration costs. As a general matter, a BA with few resources and a smaller load will reach a higher penetration level than a larger BA with more resources and load, and may see higher costs. It is the case, however, that even at lower penetration levels, a large BA with substantial resources and load may have significant integration costs if it does not have flexible capacity resources. In contrast, a small BA with a surplus of flexible generation may not have significant integration costs.

The argument is often made that, if there is more load relative to VERs installed capacity in a BA, then the variability of the wind is "lost" in the variability of the load and significant, additional reserves are not needed to balance the wind. This only means that BAs with lower wind penetration levels are more able to socialize the costs of integrating smaller amounts of wind because the cost of wind balancing is still far smaller than the cost of load balancing. This does not mean that the costs of integrating wind are less and consolidation of BAs should not be used as a rationale for socializing costs.

It is the case, however, that BAs that are facing higher wind penetration levels than their neighbors can enter into agreements to share the diversity of loads and error in their systems to delay or lessen the amount of new resources a BA must purchase to integrate the wind generation in its area, and there can be savings in that area that benefit wind generation. The amount of savings will depend on factors specific to each BA – the types and amount of dispatchable resources in the BA, the amount of VERs in the BA, the characteristics of the BA loads and the characteristics and abilities of neighboring systems. Savings depend on the presence of uncommitted balancing reserves in the consolidating or coordinating BA that are available at less than the marginal cost of new capacity, the availability of uncommitted transmission capacity between the BAs, and other factors.

> 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 should not encourage consolidation but should let the economics of each situation determine whether consolidation is desirable. The BAs have the best knowledge of their resources, needs and their systems' abilities, and are in the best position to evaluate the effectiveness and costs of additional coordination arrangements. Action by a rulemaking is inadvisable due to the inherent differences in BAs and the lack of experience with high wind penetration levels. If the Commission has specific information that a Transmission Provider operating a BA is engaged in specific, unduly discriminatory practices, the Commission should take those matters up on a case-by-case basis.

> 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 coordinatio*n?

The Commission has identified many of the possible forms of coordination. The feasibility and possible effectiveness of some of these types of Wide-Area Agreements are being discussed in the Northwest. These include:

- The possible benefits or disadvantages of a virtual BA beyond the coordination agreements already in place, such as ACE Diversity Initiative and reserve sharing agreements through the Northwest Power Pool;
- Northwest transmission providers are taking steps to test and increase the amount of dynamic scheduling that can be utilized under the present system.

The Commission should allow and encourage BAs to investigate these coordination tools to determine which, and in which combinations, might benefit their systems in integrating VERs. As noted above, mandating coordination or particular forms of coordination is inadvisable due to the inherent differences in BAs and the lack of experience with high wind penetration levels.

5. Suitability of Reserve Products and Reforms to Encourage Efficient Use of Reserve Products

The *pro forma* OATT's existing ancillary service products do not reflect the use of capacity by VERs or recover the cost of that capacity, and this should change. BPA has adopted a service and a rate for wind integration and others have filed rates at the Commission to institute similar services. All costs must be fairly charged out in order to avoid a subsidy and promote efficient use of generating flexibility.

With regard to the Commission's questions in paragraph 36 of the Notice:

> 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*?

As noted above in these comments, better forecasting may permit the BA to set aside less capacity on units in non-spinning status (capacity for following and flattening trends over the course of an integrated hour). Even perfect forecasting, however, does not eliminate the need for regulation and load-following for the native variability of the resource.

> 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*?

A reserve service and rate should quantify and price the regulation, load-following and imbalance capacity reserve components individually. Making the cost of imbalance capacity explicit, for example, will provide information to VER operators regarding the value of better scheduling. It will also provide information to the VER generator and to the market regarding the savings that might be available from self-supply of one or more of these capacity components. It will also provide information to BAs regarding the value of coordination and to the market regarding the need for additional, lower cost capacity resources. If required by the Commission, a capacity reserve service should be consistent with the terms of the Generation Imbalance Service: the BA should only be required to offer the service to the extent that the BA has uncommitted capacity in its own resources or resources available to it.

6. Capacity Market Reforms

VERs are energy resources but not capacity resources. It is important to distinguish between "capacity factor," which is a measurement of how much energy a VER can be expected to produce on a planning basis over some time frame, and ability to contribute to peak system demand. Experience in the Northwest has shown that, although, in general, wind resources in the Columbia Gorge area have capacity factors of approximately 30 percent of installed capacity, they contribute nearly zero megawatts of capacity to meeting peak demand. The ability of a wind resource to sell into a forward capacity market is, therefore, limited at best. Capacity markets exist because the system requires a supply of firm, dispatchable generating capacity that is available at different time intervals to match generation and load and to otherwise maintain system reliability. If a resource has no capacity value because it has a difficult time consistently supplying capacity, then it should be unable to participate in a capacity market.

VERs are unable to generate unless they have a fuel supply. They cannot be relied on, therefore, to provide extra capacity to meet system peaks or provide Inc'ing reserves. They can be taken off-line, however, and dispatched down to some extent by feathering turbine blades or taking individual turbine-strings off-line. To the extent they can do so reliably, they could provide that Dec'ing service to the power system. In no event should market rules be changed in any way that gives market participation rights to VERs that are not also available to conventional generation. More importantly, market rules should not permit VERs to operate or attempt to provide products in any way that degrades or endangers power system reliability.

C. Conclusion

PPC requests that the Commission refrain from proposing rules for the integration of VERs. Each BA faces differences that determine whether it can or cannot integrate the VER generation in its area with ease and at low-costs. A rule of general application would not promote an equitable result.

DATED this 12th day of April 2010.

Respectfully submitted,

/s/

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