UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc.	)	Docket No. ER11-3735-000

MOTION FOR LEAVE TO ANSWER AND ANSWER OF PUGET SOUND ENERGY, INC. TO COMMENTS, PROTESTS AND MOTION FOR SUMMARY DISPOSITION

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. §§ 385.212; 385.213 (2011), Puget Sound Energy, Inc. ("PSE") hereby submits this Motion for Leave to Answer and Answer to Comments, Protests and Motion for Summary Disposition [1] filed on July 5, 2011 in the instant proceeding.

I. MOTION FOR LEAVE TO FILE ANSWER

PSE respectfully seeks leave to file this answer by requesting a waiver of Rule 213 of the Commission's Rules of Practice and Procedure[2] to the extent the Answer responds to the protests and comments and not to Invenergy's Motion for Summary Disposition, which PSE may respond to under Rule 213(a)(3).[3] The Commission permits answers to answers or protests where, as here, the information provided will facilitate the

[1] Protests were filed by (1) the American Wind Energy Association ("AWEA") in conjunction with the Renewable Northwest Project ("RNP") (collectively, "AWEA"); (2) Invenergy Wind North America LLC ("Invenergy"); (3); Northwest and Intermountain Power Producers Coalition ("NIPPC"); and (4) and Pacific Gas and Electric Company ("PG&E") (collectively, "Protestors"). Comments were filed by Powerex Corp. ("Powerex"), and supportive comments were filed by the Public Generating Pool ("PGP") and the Large Public Power Council ("LPPC").
[2] 18 C.F.R. § 385.213.
[3] 18 C.F.R. § 385.213(a)(3).

Commission's decisional process or aid in the explication of issues.[4] This Answer will assist the Commission's decision-making process by aiding in the explication of issues raised by Protestors and providing additional factual and legal analysis in support of the proposed tariff amendments.

II. BACKGROUND

On June 6, 2011, PSE filed revisions to Schedules 3 and 13 of its Open Access Transmission Tariff ("OATT") to update its existing rates for Regulation and Frequency Response Service and to provide for differentiated cost recovery to serve dispatchable and intermittent generators exporting power from PSE's Balancing Authority Area ("BAA"). On June 7, 2011, the Commission issued a Combined Notice of Filing giving interested entities until June 27, 2011 to file interventions and/or protests. On June 21, 2011, in response to a request of the American Wind Energy Association and the Renewable Northwest Project (collectively, "AWEA"), the Commission granted a one-week extension of time for the filing of protests. On July 5, 2011, several intervening entities filed pleadings protesting certain portions of PSE's filing. The protests generally request that the Commission either reject or suspend PSE's filing for five months and set the matter for hearing and settlement procedures.

[4] *N. Y. Indep. Sys. Operator, Inc.*, 123 FERC ¶ 61,206 at P 29 (2008); *Cal. Indep. Sys. Operator Corp.*, 123 FERC ¶ 61,202 at P 5 (2008); *Southwest Power Pool, Inc.*, 118 FERC ¶ 61,055 at P 12 (2007) (accepting answers because they provided information that assisted the Commission in their decision-making process).

III. ANSWER

A. The Commission Should Not Impose a Five-Month Suspension In This Case.

AWEA, Invenergy, NIPPC, and PG&E variously argue that PSE's filing should be suspended for the maximum five-month statutory period.[5] PSE submits that each of their arguments fail to address, much less satisfy, the Commission's applicable standard for imposing a five-month suspension on PSE's proposed rate changes.

The Commission determines whether to suspend a rate increase for the maximum five-month statutory period on a case-by-case basis.[6] The Commission's general policy is that "a utility's increased rates will be suspended for only one day instead of the five month maximum in those cases where our preliminary analysis indicates that no more than ten percent of the increase appears to be excessive."[7] Here, none of the protests have even attempted to demonstrate, much less shown, that more than 10% of PSE's proposed rate increase is excessive under the *West Texas* standard. Instead, they largely repeat the same general policy objections to PSE's proposed differential purchase obligation for exporting intermittent generators that they raised in response to the VERs NOPR, and which AWEA raised unsuccessfully in the *Westar* proceeding.[8] Other than to state the obvious that the proposal is a new type of differentiated regulation charge, the protesting parties make no attempt to show that 10% or more of PSE's proposed

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[5] *See* AWEA at 24-25; Invenergy at 19; NIPPC at 19; PG&E at 12. To the extent that protestors seek summary rejection of the filing, they also fail to provide any legal authority to support such a result. Summary rejection would only be appropriate in a "clear case of a filing that patently is either deficient in form or a substantive nullity" which clearly is not the case here. *Municipal Light Bd. v. FPC*, 450 F.2d 1341 at 1345 (D.C. Cir. 1971).

[6] *W. Tex. Utils. Co.*, 18 FERC ¶ 61,189 (1982); *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 134 FERC ¶ 61,242 at P 26 (2011) (suspending rates for nominal period where rate increase had not been shown excessive under *West Texas* standard); *N. States Power Co.*, 131 FERC ¶ 61,188 at P 36 n. 7 (2010)(rejecting request for five month suspension under *West Texas* because customer had failed to demonstrate that the rate increase was likely to be excessive).

[7] *W. Tex. Utils. Co.*, 18 FERC at p. 61,375.

[8] *See infra* at 12-14.

regulation capacity rate increase is excessive. This is not surprising since PSE's proposal is fully supported, cost-justified and consistent with the Commission's regulations and precedents.

Moreover, the Commission has found that the application of *West Texas* warrants shorter suspension periods in circumstances where suspension for the maximum period would lead to harsh and inequitable results.[9] Suspension of PSE's proposed tariff changes for the maximum five-month period would lead to harsh and inequitable results in this case because it would permanently deny PSE legitimate cost recovery during the five-month suspension period. The Commission recognized in the VER NOPR and in *Westar* that intermittent generators impose new costs on a utility's transmission system that the Commission's *pro forma* tariff is not presently designed to recover.[10]

In this case, PSE has been providing Invenergy's Vantage wind facility with generator regulation service under Schedule 13 using a rate schedule that is based upon the facts as they existed in 1996, not based upon today's reality where wind generation imposes substantial new challenges on a balancing authority charged with maintaining system stability while accommodating variable wind generation. PSE is therefore grossly under-recovering the cost of providing regulation service under Schedules 3 and 13, particularly generator regulation service to Invenergy's Vantage facility, and has been since the plant started scheduling transmission for the full output of the project in 2010.

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[9] *Allegheny Power Sys. Operating Cos*., 111 FERC ¶ 61,308 at P 51 (2005).

[10] *See Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, 75 Fed. Reg. 75,336 (Dec. 2, 2010), FERC Stats. & Regs. ¶ 32,664 at P 75 (2010) ("VER NOPR") (considering the question of whether the "*pro forma* OATT [should] be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs."); *Westar Energy, Inc*., 130 FERC ¶ 61,215 at P 35 (2010) ("*Westar*") (allowing Westar to charge intermittent generators a higher regulation charge than dispatchable generation exports).

A five-month suspension of PSE's proposed tariff revisions would further and irreversibly prolong PSE's under-recovery of legitimate costs.

PSE submits that the Commission should accept PSE's filing, effective August 5, 2011, without suspension or hearing. If, however, the Commission decides that the filing requires further investigation and should be set for hearing and settlement procedures, then PSE's proposed rates should be allowed to become effective, subject to refund, after a nominal suspension period. It would not impose an undue hardship on Invenergy, the only PSE transmission customer to protest the rate increase. Invenergy would fully recover, with interest, any amounts collected under the proposed rates that are later found to be unjust and unreasonable in this proceeding. Moreover, Invenergy has been on notice since at least June 14, 2010, when PSE filed its proposed Schedule 12 Following Capacity service in Docket No. ER10-1436 (a proceeding in which Invenergy actively participated) that PSE's current Schedule 13 generator regulation rates were insufficient to recover the actual costs of providing the generation capacity needed to integrate the Vantage facility into PSE's transmission system while preserving system reliability.[11] Invenergy has now enjoyed 10 months of below-cost generator regulation service at the expense of PSE's retail customers; it should not be granted an additional five-month phase-in period. The Commission should allow PSE's proposed revisions to Schedules 3 and 13 of its OATT to become effective with no or nominal suspension.

[11] Vantage's transmission service agreement with PSE also contains a specific reference to a future wind integration ancillary service. *Puget Sound Energy, Inc.*, Original Service Agreement No. 476 – Service Agreement for Firm Point-To-Point Transmission Service, dated as of April 30, 2010, by and between Puget Sound Energy, Inc. and Vantage Wind Energy LLC, Docket No. ER10-3104-000 (filed Sept. 28, 2010).

B. The VER NOPR is Not a Barrier to PSE's Proposal To Recover the Current and Verifiable Costs of Providing Regulation Service.

Protestors assert that PSE's filing should be rejected because it is inconsistent with the Commission's recent VER NOPR, which proposes to require that transmission-owning utilities adopt voluntary 15-minute scheduling protocols, implement centralized generation forecasting, and collect a year's worth of generator output data with these practices in place ***before*** filing for differentiated generator regulation rates.[12] Outright rejection of PSE's filing on this basis is flatly wrong as a matter of law. The findings upon which the VER NOPR's proposed Schedule 10 cost recovery mechanism are predicated are preliminary at this time: "The Commission ***preliminarily*** finds that clarifying the manner by which public utility transmission providers may recover the costs associated with fulfilling their obligation to offer this service will remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery."[13] The Commission's preliminary findings were objected to by a significant contingent of the utility industry,[14] and unless and until adopted in a final rule, such preliminary findings do not disturb the Commission's existing practice of considering utilities' proposals to recover the cost of providing generator regulation service on a case by case basis.[15] The appropriate venue for protestors to express their

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[12] *See* AWEA at 3; Invenergy at 5; PG&E at 6; NIPPC at 3. *See also Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,149 at PP 97, 106-107 (2010).
[13] VERS NOPR at P 87 (emphasis added).
[14] *See, e.g.*, Comments of Edison Electric Institute, Docket No. RM10-11-000 (filed Mar. 2, 2011).
[15] The Commission adopted, in Order No. 890, a case-by-case approach to filings by public utility transmission providers seeking to recover the costs of additional regulation reserves associated with providing generator imbalance service. *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. [Regs. Preamble 2006-2007] ¶ 31,241 at P 689 n. 401; *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2,984 (Jan. 16, 2008), FERC Stats. & Regs. [Regs. Preamble 2006-2007] ¶ 31,261 at PP 689 n. 401 & 690 ("To the extent a transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service, it must do so via a separate FPA Section 205 filng demonstrating that these

support for a uniform approach, and their displeasure with the existing case-by-case approach to generator regulation charges established in Order No. 890, is in the VER NOPR rulemaking proceeding, Docket No. RM10-11.[16]

Implementation of 15-minute scheduling requires coordination and consistent practices among other balancing authorities in the region to be meaningful for generators subject to PSE's Schedule 13 who are selling outside the PSE BAA. As described in greater detail by PSE in its comments in response to the VER NOPR, "while the region is actively moving in the direction of 30-minute scheduling and concomitant intra-hour market liquidity, it is not yet ready to implement 15-minute scheduling in a meaningful way."[17] The Bonneville Power Administration ("BPA"), whose transmission system Invenergy must traverse to reach its customer, recently stated that it does not currently have the ability to accept schedules on regular 15-minute intervals and that it is not likely or feasible that BPA could implement 15-minute scheduling on its system during the WP-12 rate period, which runs through September 30, 2013.[18]

It is important to recognize that PSE is itself investing heavily in wind generation, is currently paying BPA's wind integration charges for its wind generation located in BPA's balancing area, and is subject to BPA's Environmental Redispatch policies. As a

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costs were incurred correcting or accommodating a particular entity's imbalances.") (2007); *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008); *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009); *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *appeal vol. dismissed Nat'l Rural Elec. Coop. Ass'n. v. FERC* (DC Cir. No. 08-1278).

[16] PSE notes that, contrary to its stated position in its protest, PG&E disagreed with the VER NOPR's proposed approach to generator regulation cost recovery in its comments in the rulemaking proceeding, urging the Commission "not to mandate how costs should be allocated at this time, but rather to support the regional collaboration of efforts necessary to study these issues and to develop solutions that support appropriate alignment of costs." See Comments of PG&E on Notice of Proposed Rulemaking, Docket No. RM10-11-000 (filed Mar. 2, 2011).

[17] PSE Comments at 6, Docket No. RM10-11-000 (filed Mar. 2, 2011).

[18] 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12), Administrator's Draft Record of Decision, BP-12-A-01, p. 285 (June 2011) *available at* http://www.bpa.gov/corporate/ratecase/2012/docs/BP-12%20Draft%20ROD%2006-14-11.pdf

result, PSE is fully committed to regional grid reform initiatives in the Pacific Northwest, including those that would implement region-wide intra-hour scheduling and an intra-hour market for energy and capacity. But as the Commission noted in *Westar*, "these reforms are not before the Commission in this proceeding. Here, the issue before the Commission is whether [the utility's] proposal … is just and reasonable."[19] Until scheduling reforms are implemented on a regional basis, and until there is a liquid intra-hour market for capacity and energy in the Pacific Northwest, PSE will need to continue to supply regulation capacity from its own generation resources, and gauge its regulation needs on an hourly basis. The Commission must evaluate PSE's proposed tariff changes in this context.

C. PSE's Proposed Tariff Changes Are Consistent With the Approved *Westar* Methodology, Recognizing Differences in Regional Market Structures.

The Commission evaluates proposals by utilities to charge exporting generators for generator regulation service on a case-by-case basis.[20] At the time of PSE's filing, *Westar* was (and still is) the only utility with a FERC-approved regulation rate schedule that incorporates a differentiated regulation purchase obligation for intermittent generator exports. The methodology used to develop the differentiated purchase requirement approved by the Commission in *Westar* consisted of (a) the measurement of deviations between wind generator output and a persistence forecast in the Westar balancing area; (b) calculation of the amount of regulation capacity that would be needed to offset the measured wind deviations within a 95% confidence interval; and (c) reduction of the

[19] *Westar* at P 42.
[20] *See supra* note 15. *See, e.g.*, *Entergy Servs. Inc.*, 120 FERC ¶ 61,042, at PP 62-66 (2007); *Sierra Pac. Res. Operating Cos.*, 125 FERC ¶ 61,026 (2008); *Nw. Corp.*, 129 FERC ¶ 61,116 (2009), *order on reh'g*, 131 FERC ¶ 61,202 (2010); *Westar Energy, Inc.*, 130 FERC ¶ 61,215 (2010); *Puget Sound Energy, Inc.*, 132 FERC ¶ 61,128 (2010).

resulting standalone regulation requirement to account for any offsetting deviations from load and dispatchable generation, known as the "portfolio wide" approach.[21] PSE, following discussions with FERC Staff, modeled its filing after the methodology approved in *Westar*. The methodology used by PSE uniformly incorporates each of the three principal elements of the *Westar* methodology described above.

Protestors assert that PSE's filing should nevertheless be rejected because it is "inconsistent" with *Westar* in several regards: (a) the Westar proposal was approved by the Commission as an interim measure until the 2013 creation of an SPP-wide unified balancing area and ancillary services market; (b) Westar operates in an organized market with 10 minute scheduling; and (c) Westar and SPP develop centralized wind forecasts every 10 minutes.[22] These so-called inconsistencies are solely the result of PSE's location, unlike Westar, in a region without an organized market or Regional Transmission Organization ("RTO") structure. Rather than provide a basis for rejection or modification of PSE's proposed tariff changes, these differences between the SPP RTO environment and the Pacific Northwest simply highlight why PSE had to tailor the Westar methodology to accurately reflect PSE's market structure and associated costs.

For example, if PSE operated in a region like SPP where there was a 10-minute market for energy and capacity, it may be logical to measure the deviations between schedule and output every 10 minutes using a 10 minute persistence forecast as Westar did to determine the regulation percentage. In the context of a liquid 10-minute market, a transmission provider like Westar can reposition its system in response to changes in load and generation schedules using its own resources and those available to it through the

[21] *See Westar* at P 37 ("Westar's portfolio wide-approach appropriately shares the diversity benefits among generators and load, and does not inappropriately allocate costs to any one customer").
[22] *See, e.g.* AWEA at 10-12; Invenergy at 6-7; NIPPC at 4-5; PG&E at 4-6.

market every 10 minutes. Westar is therefore able to recalibrate its regulation needs every 10 minutes.

PSE must operate in the Pacific Northwest and within the market and scheduling structure that exists there. PSE must make decisions about what generation resources it is going to make available to provide regulation service on an hourly basis, commit its other resources to hourly load schedules or sales of energy into the hourly market, and there is no opportunity to reposition its system with additional energy or capacity until the next scheduling hour. It is for this reason that PSE determined its regulation purchase obligation by measuring the deviation between output and a single 60 minute persistence forecast, and not a new 10 minute persistence forecast every 10 minutes.

While NIPPC correctly points out that PSE has adopted business practices which allow for scheduling changes on the half-hour,[23] these intra-hour scheduling protocols – like those adopted on June 28, 2011 by BPA – are voluntary. Moreover, until June 28, 2011, no exporter could take advantage of PSE's business practice because BPA would not accept such a schedule. As of the date of this filing, and since June 28, Invenergy's Vantage plant has only revised its schedule once on the half-hour. Unless PSE gets a long-term firm commitment from an exporting generator to consistently update its schedule on the half hour with the best forecast the generator has available, PSE must operate under the assumption that the hourly schedule will not be revised on the half hour and plan to dispatch its generation resources for regulation based on the hourly schedule.

Even if the Vantage plant consistently updated its schedule on the half hour, this would have minimal impact on the manner in which PSE operates its system in the context of the hourly market in which it operates. Without a matching intra-hour, liquid

[23] *See* NIPPC, Attachment A.

market for energy and capacity in the Pacific Northwest, PSE still cannot reposition its system within the hour with additional market-sourced regulation capacity in response to the changed Vantage schedule. For this reason, it is appropriate for PSE to measure the regulation requirement of intermittent generation by comparing a generator's output to a single, hourly persistence forecast.

NIPPC also points to the regional efforts by ColumbiaGrid that could result in a decision by October 11, 2011 to develop an energy imbalance market in the region as a reason to attach the "interim" tag to the PSE tariff changes as the Commission did in *Westar*.[24] Unlike the SPP Energy Imbalance market in *Westar*, which had a firm implementation date of 2013 at the time of Westar's filing, there is no firm plan yet in place for the development of a similar market in the Pacific Northwest, and there is no timeline for the implementation of any plan that might be adopted by ColumbiaGrid.[25] In addition, the development of an energy imbalance market out of whole cloth would likely face additional hurdles not faced by the SPP proposal. At this time, it is unclear what degree of cost savings, if any, PSE would recognize from an imbalance market with respect to providing regulation service. As a result, there is no reason for PSE's proposed tariff changes to be subject to an interim label, anymore than any other filed utility tariff is subject to review by the Commission on its own initiative or upon customer complaint under FPA Section 206.

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[24] NIPPC at 5.

[25] *See* "ColumbiaGrid Members' Statement of Alignment on Energy Imbalance Market Opportunities", dated June 17, 2011 (stating that "The evaluation and possible implementation of an energy imbalance market is likely to be a multi-year effort and there are considerable uncertainties about the ultimate success and finer details of the eventual end-state.") *available at* http://www.columbiagrid.org/client/pdfs/CGMembersStatementofAlignmentonEIM(061711).pdf

The different market structures in place in SPP and the Pacific Northwest determine to a large extent the manner in which a utility manages its resources to provide regulation service. As a result, there are bound to be different assumptions used to measure regulation requirements in the two regions, and these assumptions will lead to different revenue requirements for the utilities providing the service. This does not mean that a utility's demonstrated, verifiable cost of service in one region is any more or less legitimate than that of a utility in a different region. So long as the filing utility follows the portfolio-wide approach to calculating the regulation purchase obligation approved by the Commission in *Westar* – as PSE did here – it should be entitled, on a case-by-case basis, to "reasonably assess[] intermittent generation a higher regulation requirement consistent with cost causation principles."[26]

D. PSE Properly Calculated the Generator Regulation Purchase Obligation Under Schedule 13.

1. The Arguments in the Brendan Kirby Affidavit In Opposition to Lloyd Reed's Portfolio-Wide Study Were Considered and Rejected in *Westar*.

Attached to AWEA's protest is the Affidavit of Brendan Kirby, which argues that "Puget's grouping of entities for the purpose of calculating regulation burden arbitrarily imposes a greater burden on entities in smaller groups."[27] AWEA elaborates that "after the Commission staff pointed out that Westar had made its 'pie' too large by grossly overstating the size of one piece (the 'incremental' regulation needs associated with wind energy), Puget has responded by proportionately shrinking all pieces of the pie to make the overall pie the right size, even though this fails to resolve the underlying problem that

[26] *Westar* at P 36.
[27] AWEA, Kirby Aff. at P 1. See also AWEA at 20-21; See also Invenergy at 7.

intermittent generators' share of the pie is still too large."[28] AWEA raised identical arguments in opposition to Westar's revised, portfolio-wide methodology in Docket No. ER09-1273-000, and those arguments clearly did not prevail.

In the *Westar* proceeding, AWEA filed a February 12, 2010 protest in response to Westar's January 19, 2010 Response to Deficiency Letter and Supplemental Filing. It was in Westar's supplemental filing that it had proposed the "portfolio wide" methodology that was ultimately approved by the Commission in *Westar*, and which has already been described in this Answer. AWEA's protest to the Westar supplemental filing included an Affidavit from Brendan Kirby which argued that:

> Westar['s portfolio wide approach] attempted to use a mathematical shortcut to scale all estimated regulation needs down to ensure that the total estimated regulation need was equal to the total actual regulation need. Unfortunately, this shortcut failed to resolve the critical issue that wind plants were being assigned an excessively large share of the total regulation needs.[29]

The Commission in *Westar* did not agree with this argument, and approved Westar's Schedule 3A with a regulation requirement derived through the portfolio wide methodology. Now, Mr. Kirby and AWEA, along with Invenergy,[30] are making the exact same argument with respect to PSE's application of the portfolio-wide methodology approved by the Commission in *Westar – i.e.*, that the portfolio wide methodology should be revised to reduce the portion of the pie assigned to intermittent generators. AWEA even recycled the same pie analogy from its rehearing request in the *Westar* proceeding, wherein it stated that:

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[28] AWEA at 21.
[29] AWEA Comments, Kirby Aff. at 22-23, Docket No. ER09-1273-000 (filed Feb. 12, 2010).
[30] Invenergy at 7 ("Puget grouped the entities in a discriminatory manner that allocates a higher regulation burden to those entities arbitrarily assigned to smaller groups.").

> Westar responded by proportionally shrinking all pieces of the pie to make the overall pie the right size, even though this fails to resolve the underlying problem that intermittent generators' share of the pie is still too large.[31]

The essence of AWEA's pie analogy, and the reason the Commission rejected its theory in *Westar*, is that by calculating the true incremental system impact of wind generation, it would unfairly assign all the benefits of offsetting system variability to wind generation, and not to other sources of variability on the system like load and dispatchable generation. As the Commission noted in *Westar*, the "portfolio-wide approach appropriately shares the diversity benefits among generators and load, and does not inappropriately allocate costs to any one customer."[32]

In short, the methodology used by PSE witness Lloyd Reed to develop the Schedule 13 purchase obligation for intermittent generators was developed using the same portfolio wide approach used by Westar and ultimately approved by the Commission. AWEA's arguments regarding the piece of the regulation pie assigned to intermittent generators were rejected in *Westar*; and they should be rejected here.

2. A Sixty Minute Persistence Forecast is an Appropriate Methodology to Calculate Wind Deviations on PSE's System.

Protestors assert that it was inappropriate for PSE witness Lloyd Reed to use a 60 minute persistence forecast as a "proxy" for a generator's transmission schedule because PSE's transmission customers may submit transmission schedules up to twenty minutes before the start of the operating hour.[33] They contend that shorter persistence intervals between the time of the forecast and the start of the scheduling hour greatly reduce the

[31] *See* AWEA Request for Rehearing in Docket No. ER09-1273-002, at page 13 (filed April 20, 2011).
[32] *Westar* at P 37.
[33] *See, e.g.* Invenergy at 8-10.

regulation burden, and there was therefore "no apparent reason for setting the wind schedule, or any other schedule, a full hour before the operating hour."[34]

The use of a 60 minute persistence forecast to determine generator variability is appropriate because 60 minutes before the operating hour is the timeframe during which PSE makes resource decisions on its system. Moreover, a 60 minute persistence forecast was a more accurate predictor of the next hour's output from Invenergy's Vantage plant during the October - December 2010 period than the transmission schedules that the facility submitted to PSE up to 20 minutes before the start of the operating hour.[35]

While PSE's transmission customers may submit schedules up to 20 minutes before the operating hour, PSE must make decisions regarding the dispatch of its generation units, market purchases, and sales between 75 and 45 minutes before the operating hour.[36] It is during this period that PSE makes decisions with respect to the identity of generation resources that will provide regulation capacity and the amount of capacity needed.[37] By the time a generator or other load submits a schedule 20 minutes before the operating hour,[38] these operational decisions have already been made (including the purchasing of any necessary transmission and the creation of e-Tags for energy transactions needed to position PSE's system), and PSE has limited flexibility to undo them. For this reason, a comparison of the generator's output to a 60 minute persistence forecast is an accurate measure of the variability that PSE must consider

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[34] *See* AWEA, Kirby Aff. at P 7.
[35] PSE considered using actual schedules from Vantage to develop the regulation percentage, but doing so would have increased the regulation percentage because a 60 minute forecast proved to be more accurate than Vantage's schedules.
[36] *See* Exh. PSE-100, Testimony of Lloyd C. Reed at 11.
[37] *Id*.
[38] Just prior to 20 minutes before the operating hour is the absolute last moment an entity can submit a non-emergency tag for approval without it being considered late according to all BA standards in the Pacific Northwest.

during the time period when it is making decisions with respect to resource availability to provide regulation reserves for the next operating hour.[39]

It should also be noted that Invenergy has mischaracterized Mr. Reed's statement about the accuracy of Invenergy's generation forecasts for the Vantage facility.[40] It is true that PSE did not have access to Invenergy's hourly forecasts for the Vantage facility during 2010.[41] Mr. Reed's statement, as quoted in the Invenergy pleading, is consistent with this position: "I found that the accuracy of the Vantage plant's hour-ahead forecasts, ***as represented by their hourly submitted transmission schedules***, were significantly worse than 60-minute persistence."[42] Invenergy's argument that the hourly transmission schedules were not fair representations of Invenergy's generation forecasts, which Invenergy has just recently started to provide to PSE, begs the question: if more accurate hourly forecasts were available to Invenergy during 2010, why were such forecasts not reflected in the transmission schedules that were submitted on behalf of the Vantage plant?

PSE can only balance its system based on the transmission schedules provided by its customers. It is not enough for Invenergy to provide PSE with hourly forecasted generation output from the Vantage facility; PSE must rely on Vantage's hourly transmission schedule or a 60 minute persistence forecast to assess its regulation needs for the operating hour. In this case, the 60 minute persistence forecast yielded more

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[39] *See* Exh. PSE-100, Testimony of Lloyd C. Reed at 11.
[40] *See* Invenergy at 10.
[41] PSE and Invenergy have recently completed the data link that will allow PSE to access Invenergy's forecast data for the Vantage facility. However, this data and the forecasts derived therefrom will be of limited utility to PSE if Invenergy does not submit transmission schedules for the Vantage facility consistent with the hourly forecasts.
[42] Exh. PSE-100, Testimony of Lloyd C. Reed at 10 (emphasis added).

accurate results, and therefore a lower regulation requirement for the Vantage plant, than Invenergy's hourly transmission schedules.[43]

3. PSE Accurately Calculated The Dispatchable Component of its Regulation Burden.

Brendan Kirby's affidavit, which is attached to AWEA's protest, raises several objections to the manner in which Mr. Reed determined the dispatchable component of PSE's system variability. In particular, he contends that Mr. Reed "arbitrarily excluded many operational hours from the calculation of conventional generators' regulation burden" including "deviations during the ramping intervals of conventional generation, which is a major source of the regulation burden associated with integrating traditional generation."[44]

Mr. Kirby's argument ignores the fundamental difference between the ramping of dispatchable generation, which is done consistently with the dispatch instruction of the system operator, and the random ramping of intermittent generation, which is weather dependent and not at the instruction of the system operator. Excluding the ramping periods of dispatchable generators does not, as Mr. Kirby suggests, assume that there is no regulation burden associated with dispatchable generators during this period. Instead, it appropriately assumes that the regulation burden during ramping periods is the same as that during steady state operation -– *i.e.*, that the generator is meeting its dispatch instructions as well during ramping periods as it does during steady state operation. Additionally, the exclusion of forced outage periods from the assessment of the dispatchable regulation requirement is appropriate because forced outages trigger

[43] *Id*.
[44] AWEA, Kirby. Aff. at PP 2-3.

contingency reserves and therefore do not need to be managed with regulation service.[45] No adjustments for forced outages on wind plants were made in the computation of the wind regulation requirement since there were no high speed cutout events at Wild Horse during calendar year 2010 or at Vantage during the October – December 2010 period that would have qualified for the utilization of PSE's contingency reserves.

Mr. Kirby further argues that "Puget used a scaling method to calculate the regulation burden of its conventional generators that may be inaccurate," ostensibly because "Puget excluded over half the generation fleet..."[46] PSE's scaling of a subset of its dispatchable generation fleet to approximate the regulation burden of the entire fleet was a conservative simplifying assumption that likely increased, rather than decreased, the overall regulation burden associated with dispatchable generators. The fact is that none of the dispatchable generators on PSE's system show significant degrees of variability as compared to wind generators, so PSE chose two plants each from the representative categories of combined cycle and simple cycle gas plants, coal plants, and hydro plants and scaled the variability of these representative groups to the size of PSE's entire dispatchable generation fleet.[47] If PSE had actually measured and included the variability of each individual dispatchable generating unit on its system, there would have been additional diversity benefits among PSE's fleet of dispatchable units and this piece of the pie likely would have shrunk – thereby increasing the size of Invenergy's piece of the pie in the portfolio-wide analysis (to borrow AWEA's analogy).

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[45] *See* Exh. PSE-100, Testimony of Lloyd C. Reed at 26-27.
[46] AWEA, Kirby Aff. at PP 4-5.
[47] PSE's share of the Mid-C hydro plants were not included in the scaling calculation since these units are operated on Automatic Generation Control ("AGC") and are continuously being ramped up and down to provide system flexibility in response to PSE's dispatch control signal.

4. It Was Appropriate to Include the First Three Months of Data Available From the Vantage Wind Facility Within the Most Recent Full Calendar Year of Variability Data That PSE Used to Determine the Regulation Requirement.

Protestors argue that it was inappropriate to include the first three months of data from Invenergy's Vantage facility when calculating the regulation requirement of intermittent generation.[48] These arguments are unpersuasive. PSE's regulation purchase obligation for intermittent generation was determined using a full year of the most recent and best data available – calendar year 2010 – which included a full 12 months of operation from PSE's Wild Horse facility and three months of operation from Invenergy's Vantage facility.[49] The degree of variability measured at the Vantage and Wild Horse facilities (which are located in the same wind shed) during 2010 was in fact consistent with the degree of variability measured at the Wild Horse facility from 2008 - 2009 and therefore accurately reflects the expected variability of wind facilities in the area where Wild Horse and Vantage are located.[50]

Rather than a "start up period," as Invenergy characterizes October – December of 2010,[51] the Vantage facility was operating at or near full output during this entire period. In fact, Invenergy began submitting transmission schedules for the Vantage facility on August 25, 2010. The impact of the inclusion of three months of operating data from Vantage, moreover, is muted by the fact that the study period also includes twelve months of data from Wild Horse, a facility that is two and a half times the size of the Vantage facility and located within the same wind shed. Thus, the protestors' criticisms in this regard are not valid.

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[48] *See, e.g.* AWEA, Kirby Aff. at P 8, Invenergy at 8; PG&E at 5.
[49] *See* Exh. PSE-100, Testimony of Lloyd C. Reed at 18.
[50] *Id*. at 8.
[51] *See* Invenergy at 8.

E. PSE's Regulation Capacity Rate is Correctly Based on the Weighted Average Cost of Capacity in the Pool of Resources Used By PSE to Provide Regulation Service.

Invenergy argues that PSE based its proposed capacity rate on the wrong pool of generation resources.[52] It contends that PSE should "recalculate the unit charge based on the actual participation of the generation resources it uses to meet regulation needs, weighted according to their relative participation in meeting these needs."[53] Invenergy cites the recent PacifiCorp filing in Docket No. ER11-3643-000 as support for its assertion that "[i]dentifying the units expected to participate and then weighting their costs by actual or expected participation also is consistent with Commission precedent."[54]

PSE's regulation capacity rate was developed in a manner consistent with the approach that the Commission has approved for pricing capacity related ancillary service products for many other utilities in the Pacific Northwest and elsewhere – that is, to identify a suite of generation resources used by the system operator to provide regulation reserves, and then determine the weighted average cost of that suite of resource based on the capacity of the generating facilities in the suite.[55] Indeed, PSE's current capacity rate for regulation service was developed in Docket No. ER97-4468-000 using the capacity-weighted average cost of a suite of PSE resources. PacifiCorp, on the other hand, has

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[52] Invenergy at 11-13.
[53] *Id.* at 14.
[54] *Id.* at 13 fn. 35 (citing *PacifiCorp*, Filing Revising Open Access Transmission Tariff, Docket No. ER11-3643-000 (May 26, 2011), Exhibit PAC-4, Prepared Direct Testimony of Alan C. Heintz on Behalf of PacifiCorp, at 25-26 ("[T]he proposed rates are based on the weighted fixed costs of the units identified in Attachment B. The weighting is calculated by applying the same method used by the Commission in recent years to determine the units most likely to provide off-system sales. Specifically, the approach weights the units based on their participation in providing the reserves.").
[55] See Exh. PSE-200, Testimony of Michael V. Tongue at 10 (citing Avista Corporation – Docket No. OA96-162 – and Idaho Power Company – Docket No. ER96-350 – as examples of this standard methodology).

recently proposed to identify and allocate capacity costs to a pool of generation resources by weighting the resources' actual, historical contribution to available reserves.[56] While the PacifiCorp filing suggests that this methodology has been approved by the Commission for use to identify the generation units most likely to make off-system sales, PacifiCorp and Invenergy both fail to cite a single example or instance where PacifiCorp's proposed methodology was used to determine an ancillary service capacity rate.

Invenergy's preference for the PacifiCorp approach appears to ignore the nature of regulation service as a capacity product. No matter how much the units were actually used within the hour to respond to system variability, the utility still must recover the fixed costs of having the facilities in the ground and in working order so that they can be available to provide regulation capacity when needed. Therefore, the average weighted (by unit capacity) cost of a pool of resources is an appropriate means of calculating a regulation capacity rate.

Invenergy argues in the alternative that PSE, if it is going to determine the regulation capacity rate using the capacity-weighted average cost of a pool of resources, should not exclude any of its generation resources from the resource pool.[57] Once again, Invenergy's suggestion is not required by or consistent with Commission precedent.[58] A proper regulation capacity rate should reflect the resources that a utility uses to provide the service. To the extent any PSE resources were excluded from the pool, it is because

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[56] *PacifiCorp*, Filing Revising Open Access Transmission Tariff, Docket No. ER11-3643-000 (May 26, 2011), Exhibit PAC-4, Prepared Direct Testimony of Alan C. Heintz on Behalf of PacifiCorp, at 25-26 ("[T]he proposed rates are based on the weighted fixed costs of the units identified in Attachment B. The weighting is calculated by applying the same method used by the Commission in recent years to determine the units most likely to provide off-system sales. Specifically, the approach weights the units based on their participation in providing the reserves.").
[57] Invenergy at 14, fn. 37.
[58] *See supra* note 54.

such units, in the experience of the system operator, are not used to provide regulation service.[59] PSE's proposed capacity rate is therefore appropriately based on the weighted average cost of the pool of generation resources used to provide regulation service.

F. PSE's Proposed Capacity Rate is Fully Supported By the Data Required Under Part 35 of the Commission's Regulations and Is Consistent With FERC Precedent.

1. Inclusion of Regulatory Assets in Rate Base is Necessary to Accurately Reflect and Recover the Fixed Costs of The Associated Capacity Resources.

Invenergy contends that PSE should not have included $142,547,560 in regulatory assets related to the Rock Island and Rocky Reach PPA in its rate base.[60] The regulatory assets are directly attributable to and reflect the actual fixed costs of purchasing the capacity under the PPA, the prudence and accounting treatment of which was approved by the Washington Utilities and Transportation Commission ("WUTC"). Therefore, disallowing the recovery of these regulatory assets in PSE's regulation capacity rate would result in under-recovery of legitimate costs.

PSE and Chelan Public Utility District ("Chelan PUD") executed a new PPA on February 3, 2006 that provides for the cost-based sale of 25 percent of the output of both the Rocky Reach and Rock Island projects to PSE. The new power sales agreement is for 20 years, commencing on November 1, 2011 for Rocky Reach and July 1, 2012 for Rock Island. As a condition of the contract, PSE was obligated to make a one-time, upfront capacity reservation payment to Chelan PUD of $89 million. The WUTC approved the prudence of PSE's entry into the Chelan PUD contracts and the rate treatment for

[59] Exh. PSE-200, Testimony of Michael V. Tongue at p. 9 (identifying generation facilities that PSE does not use to provide regulation service). Only units that are not dispatchable and peaking units dedicated to reserves service were not included.
[60] Invenergy at 14-15.

recovery of the capacity reservation payment and the associated carrying costs through amortization over the 20 year life of the contracts in WUTC Docket No. UE-060266.[61] The $89 million capacity reservation payment has been accruing interest since PSE paid it in 2006, and had a balance of $133,888,235 on December 31, 2010.[62] The regulatory asset is predicted to have a balance of $132,706,885 on December 31, 2011.[63] The average Period II balance, as shown on Statement AG, is $133,297,560.[64]

As another condition of the Chelan PUD PPA, PSE is obligated to pay a security deposit of $18,500,000 at the commencement of the power sales contract on November 1, 2011. The balance of this regulatory asset, therefore, was $0 on December 31, 2010 and will be $18,500,000 on December 31, 2011.[65] The average Period II balance of this regulatory asset is $9,250,000.[66]

These two prepayments by PSE compose the $142 million in regulatory assets included in PSE's rate base related to the Chelan PUD PPA. Invenergy offers no support for its contention that the WUTC prudence and ratemaking determinations with respect to these regulatory assets should be overturned by FERC.

2. PSE Properly Included Acquisition Adjustments in Rate Base Related to the Purchase of Certain Generation Facilities.

Invenergy objects to PSE's inclusion of net positive acquisition adjustments in its revenue requirement totaling $236 million related to the acquisition of the Mint Farm and Encogen generation facilities.[67] Invenergy, notably, does not object to the inclusion of

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[61] See WUTC Order, Docket No. UE-060266 at pp 56-58 (Jan. 5, 2007), *available at* http://www.utc.wa.gov/docs/Pages/FilingIdBrowser.aspx
[62] *See* Exh. PSE-501, Statement AG – Period II.
[63] *Id*.
[64] *Id*.
[65] *Id*.
[66] *Id*.
[67] Invenergy at 15-16.

$205 million in net negative acquisition adjustments in the rate base of the Goldendale and Sumas facilities. If the purchase price of a property exceeds the book value, the acquisition adjustment will be positive and be recorded in FERC Account 114. The related accumulated depreciation is then recorded in FERC Account 115. If the book value of a property exceeds the purchase price, the acquisition adjustment will be negative and be recorded in FERC Account 108 ("Accumulated Depreciation"). PSE was able to purchase the Goldendale and Sumas facilities collectively for $205 million less than book value. Invenergy would pass along to ratepayers the benefits of these bargains and the associated negative acquisition adjustments, while unfairly denying PSE cost recovery of the positive acquisition adjustments associated with the more costly purchases of Mint Farm and Encogen. Such a result is not just and reasonable.

There is nothing inappropriate about the fact that certain of PSE's generating resources have embedded acquisition adjustments – whether positive or negative. In each case, the terms of the generation facility acquisition, including any premium or discount above or below book value, were reviewed and approved by the WUTC as a prudent, ratepayer-beneficial investment.[68]

Unlike the cases upon which Invenergy relies for its argument, PSE's acquisition of the generation facilities in question was already subject to thorough prudence review by the WUTC through PSE's least cost resource planning and acquisition processes.[69] As part of this process, the WUTC determined that the purchase price paid for the

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[68] *See* WUTC Order in Docket No. UE-090704 at PP 369 & 373 (2010)(approving Mint Farm and Sumas acquisitions); WUTC Order in Docket No. UE-011570 and UG-011571 at P 56 & Exh.A-4, p. 2.21, line 32 (2002) (approving Encogen acquisition); WUTC Order in Docket No. UE-070565 at P 31(2007) (approving acquisition of Goldendale). WUTC Orders are searchable by docket number on the WUTC website: http://www.utc.wa.gov/docs/Pages/FilingIdBrowser.aspx.

[69] *See, e.g. Duke Energy Moss Landing LLC*, 83 FERC ¶ 61,318 at 62,304 (1998), *order on reh'g*, 86 FERC ¶ 61,227 at 61,814 (1999) (seeking Reliability Must Run treatment of facilities purchased from PG&E); *Duquesne Light Holdings, Inc*., 117 FERC ¶ 61,326 at n. 47 (2006) (FPA Section 203 merger proceeding).

generation assets was the least expensive means available to PSE of acquiring additional generation capacity, including self-build alternatives. Now that PSE is required to use these non-jurisdictional generation assets to provide regulation service under Schedules 3 and 13 of its OATT, the WUTC's prior least-cost determination with respect to these acquisitions is *prima facie* evidence of the prudence and ratepayer benefits necessary to support recovery of the acquisition adjustments through FERC-jurisdictional rates.[70]

3. PSE's Claimed 11.6% ROE is Consistent with the Commission's Approved Discount Cash Flow Methodology.

Invenergy objects to PSE's proposal to recover an 11.6% return on equity ("ROE") on the ground that PSE recently filed a retail rate proposal with the WUTC seeking an ROE of 10.8%.[71] This argument is specious. The reason for the discrepancy between the two numbers is that the WUTC uses a different rate-setting methodology than FERC does for the determination of ROE. In this proceeding, PSE calculated its proposed 11.6% ROE using the FERC approved, formulaic discount cash flow ("DCF") methodology.[72] The WUTC requires a filing utility to predicate its requested ROE on the capital assets pricing model ("CAPM") and risk premium studies in addition to a DCF analysis. The CAPM and risk premium studies currently yield a lower ROE than the Commission's preferred DCF methodology, and in combination with a DCF analysis resulted in a lower requested ROE in PSE's retail rate case. The Commission is not bound to follow WUTC methodology with respect to ROE in this proceeding and,

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[70] *See supra* note 68. In any case, even if the Commission were to exclude the acquisition adjustments associated with each of the four facilities, the net impact would be a rate increase due to the magnitude of the unamortized remainder of the Goldendale and Sumas negative adjustments.
[71] *See* Invenergy at 18.
[72] *See* Exh. PSE-300, Testimony of Charles E. Olson at 8, 12-16.

notably,[73] no party has challenged the merits of PSE witness Charles Olson's DCF analysis.

G. The Proposed Tariff Changes are Not Unduly Discriminatory

Protestors argue that it is discriminatory for PSE to impose a differentiated purchase obligation on generators exporting wind generation, while not imposing the same purchase obligation on wind generation that sinks in PSE's BAA.[74] This argument is without merit.

In drafting the proposed revisions to Schedules 3 and 13 of its OATT, PSE followed as closely as possible the tariff provisions set forth in Westar's approved Schedule 3A. The Commission approved Westar's Schedule 3A, which imposed a generator regulation charge on generator exports but not generation sinking in Westar's control area.[75] Westar, in turn, modeled its Schedule 3A on earlier generator regulation schedules approved by the Commission wherein the charge was only imposed on exporting generators.[76] Thus, FERC precedent dating back to *Entergy* and *Florida Power* has allowed transmission providers to use generator regulation service to bridge

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[73] *See Kentucky Utilities Co. v. FERC*, 760 F.2d 1321, 1325-27 (D.C. Cir. 1985) (It is elementary, of course, that FERC enjoys *exclusive* jurisdiction over wholesale utility rates. The Commission is not required, in order to engage in reasoned decision-making, to address every state utility commission "precedent" which is at odds with FERC's practice . . . . FERC is not, as we noted above, bound to follow a state commission's considered judgment with respect to either accounting or ratemaking. FERC must, rather, follow its own precedents or, alternatively, provide a reasoned explanation for a material departure therefrom.) (citing *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 851 (D.C. Cir. 1970)); *Appalachian Power Co.*, 65 FERC ¶ 63,008 at pp. 65,046, 65,049 (1993) ([T]he FERC's ratemaking policies are not dictated by those of state commissions . . . . In setting a rate of return on common equity for electric utilities regulated by this Commission, use of state commission decisions is not appropriate.).

[74] Invenergy at 3-4; NIPPC at 15-16; PG&E at 7.

[75] *See Westar* at P 35.

[76] *See id*. ("The Commission finds that like the proposals accepted in *Florida Power* and *Entergy*, Westar's proposed Balancing Agreement and Schedule 3A will allow Westar to charge for generation regulation resulting from transactions involving exports of power out of the Westar balancing area.").

the cost recovery gap that previously allowed exporting generators to avoid regulation charges.[77]

H. PSE's OATT Already Allows Any Party To "Opt Out" of Schedule 3/13 Regulation Service Who Can Self Supply Regulation Capacity Into The BAA or Transfer Their Own Generation Outside the BAA With a True Dynamic Signal.

A number of the protests express concerns about whether and to what extent transmission customers will be able to self-supply regulation capacity under Schedules and 13.[78] Powerex urges PSE to "specify what types of arrangements it will consider to be 'alternative comparable arrangements' under Schedules 3 and 13."[79] In general, PSE is happy to work with any customer to facilitate an "alternative comparable arrangement" through dynamic transfer into PSE's BAA of self-supplied regulation capacity, or a dynamic transfer out of PSE's BAA of the generator's output.

Schedules 3 and 13 of the PSE OATT require the transmission customer to either purchase regulation service from PSE or "make alternative comparable arrangements." PSE appreciates the protestors concerns about the definitiveness of this tariff provision, but must also point out that the language is not new. The "alternative comparable arrangement" provision existed prior to PSE's June 6 filing in this proceeding and was not modified because PSE does not believe the necessary arrangements lend themselves at this time to a more definitive statement or detailed provisions of the type that Powerex

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[77] *See Florida Power Corp*., 89 FERC ¶ 61,263 (1999); *Entergy Services, Inc*., 120 FERC ¶ 61,042 at P 66 (2007).

[78] AWEA at 23-24 (transmission customers should be afforded the option of self-supplying reserves); NIPPC at 9-11 ("public utility transmission providers must develop 'procedures by which customers can avoid or reduce' generator regulation charges"); PG&E at 10 ("a coordinated mechanism for dynamically scheduling variable energy resources across multiple balancing area authorities within WECC does not yet exist.").

[79] Powerex at 5.

proposes. As PG&E correctly observes, "a coordinated mechanism for dynamically scheduling variable energy resources across multiple balancing area authorities within WECC does not yet exist."[80] PSE believes that the arrangements necessary to achieve a dynamic transfer – either of self-supplied regulation capacity into the PSE balancing area, or the output of an intermittent generator to a different balancing area – do not lend themselves at this time to a standard business practice.

Nevertheless, PSE would welcome the opportunity to explore either of these options (and has done so in the past) with interested transmission customers on a case-by-case basis, provided the customer is willing to buy the necessary transmission capacity and related products on neighboring systems to achieve the transfer and make any necessary system upgrades. PSE believes that any self supply or dynamic transfer that incorporates a true dynamic signal - *e.g.*, telemetry with four second scan rates – would likely qualify as an "alternative comparable arrangement" under Schedules 3 and 13 of the PSE OATT. PSE in fact has recently completed such a dynamic transfer arrangement to import the signal for its merchant-owned Mint Farm facility into PSE's balancing area, and has no reason to believe it would not be possible to achieve a comparable arrangement for any other customer.

I. Miscellaneous Other Issues Raised in the Protests

The protests raise a number of additional arguments that do not fit neatly within the categories of arguments responded to above. PSE will respond to two of these issues in abbreviated fashion below.

[80] PG&E at 10.

1. Concerns About Curtailment

PG&E and Powerex raise concerns about potential curtailment of wind generation.[81] PSE has not amended any of its tariff language concerning the feasibility of providing the necessary service or about curtailment. PSE will not curtail any generator – wind or otherwise – for economic reasons. To the extent there is a shortfall of reserves identified by the Reliability Coordinator, all PSE transmission customers – whether load, wind, third party wind, dispatchable generation, etc. – will be treated on a non-discriminatory basis to the extent practicable and consistent with Good Utility Practice. PSE does not expect this to happen, and indeed operates its system to provide a larger confidence interval than the 95% it is using for the basis of the purchase obligation for wind exports under Schedule 13. But curtailment for reliability reasons must be an option available to the system operator if and when the reliability of the system is put in jeopardy.[82] Unlike BPA's current (and proposed WP-12 rate case) wind balancing service, PSE is ***not*** proposing to limit the amount of regulation service that it makes available to wind plants to any pre-determined MW amount. Finally, in response to concerns raised by protestors, PSE currently allows exporting wind plant schedules to be tagged as "firm" pursuant to current WECC scheduling procedures.

2. Transmission Reservation as Basis for Purchase Obligation

Powerex argues that PSE should require transmission customers to buy ancillary services based on the generation source's online generation capacity, rather than the

[81] *See* PG&E at 9 (asserting that Mr. Reed's testimony "may be read to imply that PSE could use resources allocated to provide regulation services to wind resources and curtail those wind resources despite having received the significantly increased Regulation Service payments."); Powerex at 6 (asking PSE to "confirm whether it expects to subject wind generators to curtailments on the basis it has insufficient reserves.").
[82] *See* PG&E Comments, Docket No. RM10-11-000 at 20 ("Curtailment of VER generation should always be available as an option to maintain system reliability in over-generation situations.").

transmission reservation associated with the transaction.[83] This issue was debated and appropriately resolved in Order No. 888.[84] Transmission providers must stand ready to make available regulation capacity based on the customer's reserved amount of firm transmission capacity, not the capacity actually scheduled.

IV. CONCLUSION

None of the protests submitted in this proceeding provide any valid basis for rejection or suspension of the proposed rates. For the reasons stated herein, the Commission should accept PSE's proposed revisions to Schedules 3 and 13 of its OATT to become effective August 5, 2011.

Respectfully submitted,

*/s/ Richard P. Bonnifield*_____

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[83] Powerex at 14-16.

[84] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,036 at p. 31,721 (1996) ("The amount of each ancillary service that the customer must purchase, self-supply, or otherwise procure must be readily determined from the transmission provider's tariff and comparable to the obligations to which the transmission provider itself is subject"); *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1996), FERC Stats. & Regs. [Regs. Preambles 1996-2000] ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document upon all parties on the official service list compiled by the Secretary of the Commission in this proceeding.

Dated at Washington, D.C., this 20th day of July, 2011.

*/s/ Justin P. Moeller*_____

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