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

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

PREPARED DIRECT TESTIMONY OF
LLOYD C. REED
ON BEHALF OF PUGET SOUND ENERGY, INC.

## SECTION I - INTRODUCTION

**Q. Please state your name and business address.**

A. Lloyd C. Reed, 10025 Heatherwood Lane, Highlands Ranch, Colorado 80126.

**Q. By whom and in what capacity are you employed?**

A. I am the President of Reed Consulting, an independent energy consulting organization. I have been retained by Puget Sound Energy, Inc. ("PSE") to assist PSE staff with the development of revisions to Schedule 13 to PSE's Open Access Transmission Tariff ("OATT").

**Q. Please describe your educational background and professional experience.**

A. I graduated from the University of Washington with a degree of Bachelor of Science, Electrical Engineering in 1982. I have over twenty-five years experience in the Western Energy Coordinating Council ("WECC") energy markets in the areas of power marketing and trading, power systems operations, power portfolio risk management, renewable resource analysis, power contract negotiation and administration, and regulatory affairs.

**Q. Are you familiar with how PSE in particular manages loads and resources within its Balancing Authority Area ("BAA")?**

A. Yes. My background experience includes nearly two decades as an employee of PSE, serving in various positions of responsibility for operation and management of PSE's generation resources. Between 1982 and 1984, as an employee of PSE, I conducted multiple resource planning studies that were utilized in determining the operation of PSE's hydroelectric, coal, and natural-gas fired generating plants. Between 1984 and 1993, I was PSE's power scheduler/short-term marketer and my duties included developing daily load forecasts for the PSE BAA, determining the pre-scheduled dispatch points of all of PSE's generating resources, and implementing short-term wholesale power purchase and sales transactions with various counterparties. In addition, between 1999 and 2001, I was PSE's Director of Power Operations, with responsibilities that included managing all of PSE's real-time, day-ahead and short-term (up to one year) power operations functions.

**Q. Are you familiar with the impacts of wind generation in the PSE BAA?**

A. Yes. Acting as an independent consultant to PSE, I conducted a series of studies between 2003 and 2007 regarding the short-term operational impacts and associated costs of integrating the variable output of wind plants into PSE's BAA. These studies focused on the hour-ahead and day-ahead impacts of wind generation, and how PSE might manage wind generation variability. The results of these studies were utilized by PSE in its integrated resource planning process and by PSE's resource acquisition group in its acquisition of two large-scale wind projects. Various analytical tools that I originally developed have also been utilized by PSE operations personnel to help quantify the amount of flexible capacity that PSE must maintain in order for it to manage its existing wind generation.

**Q. Have you previously submitted testimony to the Commission regarding PSE's costs of supplying within-the-hour capacity to wind plants located within its BAA?**

A. Yes. I previously provided testimony in support of PSE's Schedule 12 filing, which was submitted to the Commission on June 14, 2010 in Docket No. ER10-1436. In its Schedule 12 filing, PSE proposed to provide within-the-hour Following Capacity service to wind plants located within its BAA. The Commission rejected that filing in an order issued on August 13, 2010, because the proposed rate was based on the capacity cost of a proxy unit which, the Commission found, had not been shown to be a reasonably accurate representation of the costs incurred in providing a following service to wind resources.[1]

**Q. Did PSE consult with FERC Staff after the close of proceedings in Docket No. ER10-1436?**

A. Yes. FERC Staff expressed the view that supplying the within-the-hour capacity needed to balance the output of wind plants in a utility's BAA is a component of Regulation and Frequency Response Service and not a separate following capacity service. FERC Staff suggested that the cost of supplying such intra-hour capacity should be recovered through a utility's generator regulation and frequency response ancillary service schedule in the manner approved by the Commission in *Westar Energy, Inc*., 130 FERC ¶ 61,215 (2010).

**Q. What is the purpose of your testimony in this docket?**

A. Building on the FERC Staff's guidance, PSE has asked me to recalculate the Schedule 13, Regulation and Frequency Response Service purchase obligation of wind and other non-dispatchable generation resources (hereinafter referred to as "Intermittent Purchase Obligation") that export energy out of PSE's BAA in a manner consistent with that recently approved by the Commission in *Westar Energy, Inc.*, Docket No. ER09-1273.

[1] *Puget Sound Energy, Inc*., 132 FERC ¶ 61,128 (2010).

**Q. In addition to your testimony, is PSE submitting other testimony with the Commission regarding updates to Schedules 3 and 13?**

A. Yes. In addition to my testimony regarding the recalculation of the Schedule 13 Intermittent Purchase Obligation, PSE also proposes in this filing to update its cost of service for regulation under Schedules 3 and 13 of its OATT and is submitting additional testimony in support thereof. First, in the testimony of Mr. Michael Tongue, Mr. Tongue describes the set of PSE generating resources that are utilized and capable of providing within-the-hour regulation service. Second, in the testimony of Mr. Charles Olson, Mr. Olson computes an updated PSE return on equity for use in updating the regulation rate under Schedules 3 and 13. Third, the testimony of Mr. Jim Sant will describe the capital structure, cost of long term debt, and overall rate of return to be used in calculating the updated regulation rates under Schedules 3 and 13. Finally, in the testimony of Mr. John Story, Mr. Story determines PSE's capacity-related costs of supplying within-the-hour regulation service, based upon the pool of resources identified by Mr. Tongue and the rate of return as computed by Mssrs. Olson and Sant.

**Q. Why is PSE implementing a revised purchase obligation for wind and other intermittent resources under Schedule 13?**

A. PSE provides Regulation and Frequency Response Service under Schedules 3 and 13 by constantly maintaining an amount of flexible generating capacity that can be utilized to manage the variability of load and generation. The regulation purchase obligation specified in PSE's current Schedule 13 (2.00%) for all exporting generators, dispatchable or otherwise, was developed in 1998 and was based on 1996 historical conditions. PSE did not have any wind generation within its BAA at the time the 2.00% regulation

purchase obligation was derived. However, following the addition of wind generation into the PSE BAA beginning in 2006, PSE has determined that the existing 2.00% regulation purchase obligation is not representative of the actual amounts of capacity that PSE must set aside on average each hour in order to manage the within-the-hour scheduled versus actual generation deviations of intermittent generating resources such as wind.

**Q. Based on your analysis, how much regulation capacity should wind and other intermittent resources be required to purchase under Schedule 13 to accurately reflect the amount of capacity that PSE must set aside in order to manage the within-the-hour deviations of intermittent generating resources?**

A. Following the approach approved by the Commission in *Westar*, I compared historical scheduling and forecast data of the wind generation in PSE's BAA to actual output to determine the regulation capacity needed to balance deviations in wind output within the hour. I then performed a portfolio-wide analysis, consistent with *Westar*, to give wind generation the benefit of any offsetting variability from load and dispatchable generation resources. As the analysis in Section III of my testimony demonstrates, based on their proportionate effect on system variability (and accounting for the effect of diversity benefits), transmission customers exporting energy outside the PSE BAA from wind and other intermittent resources located in the PSE BAA should be required purchase an amount of Generator Regulation and Frequency Response Service equal to 16.77% rather than the 2.00% currently required for all exporting generators. The revised Intermittent Purchase Obligation of 16.77% will allow PSE to recover a greater portion of its actual cost of supplying regulation capacity to the exporting wind plants located within its BAA

from the exporting wind plants responsible for such costs. In addition, the revised Intermittent Purchase Obligation will allow PSE to recover costs that are commensurate with an exporting wind plant's proportionate impact on net system variability while also taking into account the diversity benefits between within-the-hour variations in loads, wind resource generation, and dispatchable resource generation.

## SECTION II - OPERATIONAL CHARACTERISTICS OF PSE'S WIND PLANTS, BALANCING AUTHORITY AREA LOADS, AND DISPATCHABLE GENERATING PLANTS

**Q. Please describe the operational characteristics of wind generation.**

A. In general, the generation output of wind plants is intermittent and highly variable in nature. Since wind plants do not have any storage capability beyond the rotational inertia of the turbine apparatus, real-time power output is directly a function of the wind speed at any given point in time. Therefore, the generation output of a wind plant can vary considerably from hour to hour and even within the same hour. For example, on November 27, 2009, the generation output at PSE's Wild Horse plant was 0 MW halfway through the 0300 scheduling hour, it rose to 175 MW halfway through the 0400 hour, and dropped back to 26 MW halfway through the 0500 hour. Within the 0400 hour alone, the Wild Horse plant had both a 109 MW increasing generation ramping event and a 100 MW decreasing generation ramping event. Forecasting these kinds of wind generation ramping events is much more difficult than forecasting load ramping events, since PSE's BAA loads tend to follow established hourly customer usage patterns whereas wind generation on PSE's system displays a higher degree of randomness.

**Q. Can the output of wind plants be dispatched like conventional thermal or hydroelectric plants?**

A. No. Unlike conventional thermal and hydro plants, the output of a wind plant cannot be dispatched to operate at a specified, pre-determined generation level. It is physically possible to limit the output of a wind plant to a specified maximum generation value; however, the plant's real-time generation output would still be highly variable, and therefore unpredictable, at generation levels below the specified maximum limit.

**Q. Does PSE have any operational experience with wind plants?**

A. Yes. PSE currently owns and operates 480 MW of generation capacity from three operating wind farms. PSE began receiving the entire output of the 150 MW Hopkins Ridge wind plant, located in eastern Washington State, in late 2005. In the fall of 2008, PSE completed its Hopkins Ridge Expansion project and began receiving an additional 7 MW of added capacity. PSE began receiving the entire output of the 229 MW Wild Horse wind plant, located in central Washington State, in late 2006. In November 2009, PSE completed its Wild Horse Expansion project and began receiving an additional 44 MW of added capacity. PSE also has a long term power purchase agreement with an independent power producer for 50 MW of wind capacity from the 221 MW Klondike III wind farm located in eastern Oregon that commenced deliveries in December 2007. PSE is also in the process of constructing Phase I of its Lower Snake River ("LSR") wind project, located in eastern Washington State. 350 MW of new wind capacity from the LSR project is expected to enter commercial operation during the second quarter of 2012.

**Q. Are all of the PSE wind plants you mentioned above located within PSE's BAA?**

A. Currently, only the Wild Horse plant is located within the PSE BAA. Both the Hopkins Ridge plant and the Klondike III plant are located within the Bonneville Power Administration's ("BPA") BAA; BPA provides BAA services, including within-the-hour

Regulation Capacity services, for Hopkins Ridge and PSE's purchased share of Klondike III.

**Q. Are there any wind plants located within the PSE BAA that are not owned or operated by PSE?**

A. Yes. Invenergy Wind North America LLC's ("Invenergy") 96 MW Vantage Wind Energy LLC ("Vantage") plant. The entire output of the Vantage plant is exported out of the PSE BAA and delivered to a third-party purchaser located in California pursuant to a long-term transmission agreement. The Vantage plant went into commercial operation on October 4, 2010.

**Q. What type of historical generation data is available for the wind plants located within the PSE BAA?**

A. PSE has detailed, 4-second interval actual generation records for the Wild Horse plant extending back to when the plant first began generating test energy in 2006. PSE personnel aggregated the base 4-second interval data into 1-minute interval data, and the 1-minute data was provided to me. I subsequently verified and re-aggregated the 1-minute data into 10-minute interval data for use in determining the Schedule 13 Intermittent Purchase Obligation. A complete dataset of Wild Horse 1-minute interval and 10-minute interval generation for calendar year 2010 is contained in Table 1 of my confidential workpapers. I also examined Wild Horse generation data from calendar years 2008 and 2009 and I noted that the within-the-hour variability of the Wild Horse plant during these prior years was very similar to the variability that I observed for calendar year 2010. In addition to the Wild Horse generation data, PSE has available 4-second interval generation data for the Vantage plant extending back to when the plant

began generating test energy in mid-2010. PSE personnel aggregated the base 4-second interval data into 1-minute interval data, and the 1-minute data was provided to me for the period of time during calendar year 2010 that the plant was in commercial operation (October 4, 2010- December 31, 2010). I subsequently verified and re-aggregated the 1-minute data into 10-minute interval data for use in determining the Schedule 13 Intermittent Purchase Obligation. A complete dataset of Vantage 1-minute interval and 10-minute interval generation for the period October 4, 2010 – December 31, 2010 is contained in Table 1 of my confidential workpapers.

**Q. Do the Wild Horse and Vantage wind plants generally exhibit similar generation patterns?**

A. Yes. The Wild Horse and Vantage plants are both located approximately 75 miles east of Seattle, Washington and the two plants are physically adjacent to each other. So while the Vantage plant has only been in commercial operation since October 4, 2010, it is possible to determine the Schedule 13 Intermittent Purchase Obligation across a longer time period – for instance a full calendar year - since the generation patterns of the Vantage plant in time periods prior to its commercial in service date would be similar to the generation patterns of the Wild Horse plant. Therefore, as I explain in more detail later in my testimony, the computation of the updated Schedule 13 Intermittent Purchase Obligation utilizes Wild Horse generation data for the period January 1, 2010 through October 3, 2010, and the combination of Wild Horse and Vantage generation data for the period October 4, 2010 through December 31, 2010.

**Q. What type of generation forecast data did you utilize for the Wild Horse and Vantage plants in determining the Schedule 13 Intermittent Purchase Obligation?**

A. I utilized 60-minute before the hour persistence forecasts for both the Wild Horse and Vantage plants in the determination of the Intermittent Purchase Obligation. I also examined Wild Horse 60-minute persistence forecasts based upon calendar year 2008 and 2009 actual generation data, and I noted that the accuracy of the forecasts in these prior years was very similar to the accuracy of the forecasts that I observed for calendar year 2010.

**Q. Is it reasonable to utilize 60-minute persistence-based forecasts in the determination of the Schedule 13 Intermittent Purchase Obligation?**

A. Yes. First of all, I analyzed the forecast accuracy of the Vantage plant across the time period that the plant was in commercial operation during calendar year 2010, based upon the next-hour transmission schedules that were submitted to PSE and the plant's actual generation during that corresponding hour. 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. Therefore, utilizing 60-minute persistence forecasts for the Vantage plant as opposed to using the actual hour-ahead transmission schedules is a reasonable and conservative assumption that, in turn, acts to reduce the computed Intermittent Purchase Obligation. In the case of the Wild Horse plant, since this plant is located within the PSE BAA hourly delivery schedules are not created for the plant. This treatment is identical to how PSE's dispatchable generation plants located within the PSE BAA are managed. For internal power management and system balancing purposes to meet load-service obligations, PSE does create both day-ahead and real-time Wild Horse generation forecasts using the 3Tier forecasting system. However not all of the hour-ahead forecasts are retained by PSE. Therefore, utilizing 60-

minute persistence is also a reasonable approach in determining hour-ahead generation forecasts for the Wild Horse plant, and this approach is consistent with the treatment of the Vantage plant.

**Q. Is the use of 60-minute before the hour persistence forecasts in the determination of the Schedule 13 Intermittent Purchase Obligation consistent with the market structure in the Pacific Northwest?**

A. Yes. Currently, the Pacific Northwest market utilizes an hourly scheduling interval with schedules for the upcoming hour generally being finalized with BAA operators 20-30 minutes prior to the start of the hour. However, additional time is needed for operators of wind plants and the BAA's provider of balancing services to: (1) evaluate recent and current wind generation patterns, (2) develop next hour generation forecasts, (3) factor in these forecasts into their operation plans, (4) adjust market positions to establish necessary flexibility on internal generation for the next hour, and (5) communicate their next-hour generation schedules to their purchasing counterparties and transmission providers and to create the associated scheduling tags. Using 60-minute before the hour persistence forecasts in the determination of the Schedule 13 Intermittent Purchase Obligation is therefore reasonable and is consistent with current regional scheduling practices.

**Q. Can the datasets of Wild Horse and Vantage actual generation and forecasted generation be utilized to determine the expected value of the within-the-hour forecast generation versus actual generation of both of the wind plants located within the PSE BAA?**

A. Yes. By comparing the forecasted hour-ahead generation against the actual real-time generation, one can assess the within-the-hour variability that PSE's system must account for and determine, using statistical measures, the expected amount of deviation between forecast and actual generation exhibited by the two existing wind plants located within PSE's BAA. The hour-ahead forecasts represent the most accurate forecasts available before the start of each scheduling hour; therefore, this set of forecasts was utilized in my evaluation rather than day-ahead forecasts. Also, as I describe later in my testimony, the hour-ahead wind generation forecasts were adjusted to reflect generation ramping impacts in order to create a "best available" forecast.

**Q. What type of historical load data is available for the PSE BAA loads?**

A. PSE has detailed, 4-second interval actual BAA load records extending back for several years. PSE personnel aggregated the base 4-second interval data into 1-minute interval data for calendar year 2010, and the 1-minute data was provided to me. I subsequently verified and re-aggregated the 1-minute data into 10-minute interval data for use in the Schedule 13 Intermittent Purchase Obligation studies. A complete dataset of the 1-minute interval and 10-minute interval PSE BAA loads for calendar year 2010 is contained in Table 2 of my confidential workpapers. I also examined PSE BAA load data from calendar years 2008 and 2009, and I noted that the within-the-hour variability of PSE's loads during these prior years was very similar to the variability that I observed for calendar year 2010.

**Q. Does PSE's BAA load exhibit significant variability?**

A. Yes. The majority of PSE's BAA load consists of customers whose power usage is variable depending upon short-term weather trends. PSE's loads are most variable in the Winter Season and are least variable in the Summer Season.

**Q. Does the short-term variability of wind generation located within the PSE BAA match up with the short-term variability of PSE's BAA load?**

A. Generally speaking, no. The short-term variability in generation output at the Wild Horse and Vantage wind plants is not highly correlated with the variability of PSE's BAA load. This situation occurs since the wind plant generation output is most highly dependent upon wind speed impacts while PSE's BAA load is most highly dependent upon temperature impacts. Also, the two wind plants within the PSE BAA are located approximately 75 miles away from PSE's load center in the Puget Sound region, across a mountain pass, and the prevailing weather patterns at the wind plant sites can be quite different from the weather in the Puget Sound area.

Q. **Do the non-wind generation plants located within the PSE BAA exhibit significant short-term variability?**

A. In general, no. PSE's non-wind generating plants - which I collectively refer to as Dispatchable Plants - exhibit very little deviation between their scheduled output and their actual output. The two situations where the Dispatchable Plants may exhibit higher levels of within-the-hour variability are: (1) the case where a plant is intentionally ramped up or down in response to PSE's dispatch signal, or (2) the case where a plant endures a forced outage event that restricts the plant's generation output. However, as I explain later in my testimony, the two sources deviations noted above are not included in the determination of PSE's within-the-hour regulation requirement since in the first case

the generation variations are not caused by random fluctuations, and in the second case the variations can be managed via PSE's contingency reserves.

**Q. Does the short-term variability of the Dispatchable Plants located within the PSE BAA match up with the short-term variability of PSE's BAA load and/or wind generation?**

A. No. Disregarding intentional ramping operations, the scheduled versus actual generation deviations on the Dispatchable Plants are primarily random in nature and these deviations have a low correlation to within-the-hour load deviations and within-the-hour wind generation deviations.

**Q. What type of historical generation data is available for the Dispatchable Plants located within the PSE BAA?**

A. PSE has detailed, 4-second interval generation records for its Dispatchable Plants extending back for several years. PSE personnel aggregated the base 4-second interval data into 1-minute interval data for six representative Dispatchable Plants for calendar year 2010, and the 1-minute data was provided to me. I subsequently verified and re-aggregated the 1-minute data into 10-minute interval data for use in the Schedule 13 Intermittent Purchase Obligation studies. Complete datasets of the 1-minute interval and 10-minute interval generation for the six representative Dispatchable Plants for calendar year 2010 are contained in Tables 3a-c of my confidential workpapers. I also examined generation data for four of the six representative Dispatchable Plants from calendar year 2009, and I noted that the within-the-hour variability of the four Dispatchable Plants during this prior year was very similar to the variability that I observed for calendar year 2010.

## SECTION III– DETERMINATION OF THE SCHEDULE 13 INTERMITTENT PURCHASE OBLIGATION

**Q. Please describe the Schedule 13 Intermittent Purchase Obligation.**

A. The Schedule 13 Intermittent Purchase Obligation is a percentage quantity that is used to allocate the cost of the regulation capacity required for PSE to manage the within-the-hour generation variations of wind plants located within the PSE BAA that are exporting energy outside the BAA. In simple terms, it is the percentage of installed wind capacity in PSE's BAA that must be maintained by PSE as flexible within-the-hour generation capacity to manage the variable output from the wind generation on its system. The Intermittent Purchase Obligation is one of the three main billing determinants used to compute an exporting wind plant's charges under Schedule 13.

**Q. Please describe the general methodology by which you computed the Intermittent Purchase Obligation.**

A. I employed a six-step approach to compute the Intermittent Purchase Obligation. These steps mirror, with minor regional differences discussed below, the approach that was approved by the Commission in *Westar*. The first step was to quantify the amount of regulation capacity that is required for PSE to manage within-the-hour variations in its BAA loads, consistent with NERC and WECC reliability criteria. The second step was to quantify the variability of the wind generation located within the PSE BAA on a stand-alone basis by comparing forecast output to actual output on a 10-minute interval basis. I did this for each individual wind plant and for the combination of both wind plants located within the PSE BAA. For purposes of developing the Schedule 13 Intermittent Purchase Obligation, the data for the combination of the two wind plants located within the PSE BAA was used. The third step was to quantify the amount of regulation capacity

that is required for PSE to manage within-the-hour variability of all of the Dispatchable Plants located within the PSE BAA. The fourth step was to quantify the total amount of regulation capacity that is required for PSE to manage the combined within-the-hour variations in its BAA loads, wind generation, and Dispatchable Plants and to compute the overall system diversity benefit. In the fifth step, I determined the amount of regulation capacity required to manage within-the-hour wind generation variations by allocating the system diversity benefits determined in Step 4 between PSE's load, wind generation, and Dispatchable Plants. In the sixth and final step, the wind plant regulation capacity value from step 5 was divided by the total Installed Capacity of all wind plants located in the PSE BAA for which PSE is providing regulation capacity services to determine the Schedule 13 Intermittent Purchase Obligation. Each of these steps is described in greater detail *infra*.

**Q. How did the approach you employed differ from that taken in *Westar*?**

A.: My approach closely followed the methodology approved by the Commission in *Westar*, recognizing that there are regional energy market differences between the Pacific Northwest and the Southwest Power Pool. Westar determined the Regulation Requirement of wind plants located within its BAA by quantifying the differences between the wind plant's forecasted output and their actual output based on 10-minute forecasts. That approach was appropriate since Westar receives dispatch instructions for many of its generating plants from the Southwest Power Pool on a 10-minute basis. However, PSE and other transmission providers located in the Pacific Northwest region currently operate in an hourly-scheduled, bi-laterally traded market structure. Generation forecasts and associated transmission schedules for wind plants and Dispatchable Plants

are currently determined by PSE and other entities in the Pacific Northwest region on an hourly basis. Therefore, PSE must maintain adequate on-system regulating reserves across an hourly timeframe in order to balance the differences between hour-ahead scheduled generation and load versus the actual generation and load that occur across the hour.

**Q: Is it reasonable for PSE to use an hourly timeframe to determine PSE's regulation requirement for wind plants located within its BAA?**

A: Yes. First, more granular intra-hour scheduling and forecast data is not available to PSE as it was to Westar because of the different regional market structures. In the Pacific Northwest, wind generators do not produce production forecasts every 10 minutes because their schedules can only be adjusted on the hour. If the data were available, and PSE were to utilize the 10-minute measurement period utilized by Westar in order to determine the regulation requirement of wind resources: (1) the computation would vastly understate the amount of hourly regulating capacity that PSE actually has to maintain in order to manage wind generation deviations that are occurring on its system, and (2) the computation would be wholly inconsistent with the hourly scheduling structure of the Pacific Northwest power and transmission markets.

**Q. What time interval did you utilize when analyzing the amount of within-the-hour variability associated with wind generation, loads, and dispatchable generation in the PSE BAA?**

A. My testimony presents an evaluation of the within-the-hour variability of wind generation, loads, and dispatchable generation in the PSE BAA based upon 10-minute interval data.

**Q. Does your methodology for the computation of the Schedule 13 Intermittent Purchase Obligation recognize potential diversity impacts between within-the-hour variations in PSE's BAA load, wind generation, and dispatchable generation located in its BAA?**

A. Yes. As I will describe in detail later in my testimony, the Intermittent Purchase Obligation incorporates, and gives wind generators full credit for, the benefits of the diversity between within-the-hour variations associated with PSE's BAA load, wind generation, and dispatchable generation.

Q. **What study period did you utilize for the computation of the Intermittent Purchase Obligation?**

A. The Intermittent Purchase Obligation computations as described in my testimony and as detailed in Table 12 of my confidential workpapers are based upon calendar year 2010 historical data. I also confirmed the results of the 2010-based Intermittent Purchase Obligation computations by performing similar calculations using calendar year 2009 data; the results of the two studies were very similar with the 2010-based study resulting in a slightly lower Intermittent Purchase Obligation.

**Q. What historical data did you utilize for the computation of the Intermittent Purchase Obligation?**

A. The specific datasets utilized for the Intermittent Purchase Obligation analysis were: (1) PSE hour-ahead forecasted 2010 BAA loads, (2) hour-ahead forecasted 2010 Wild Horse and Vantage generation, (3) hour-ahead forecasted 2010 generation for selected Dispatchable Plants, (4) PSE actual 10-minute interval 2010 BAA loads, (5) actual 10-minute interval 2010 Wild Horse and Vantage generation, (6) actual 10-minute interval

2010 generation for selected Dispatchable Plants, and (7) total 2010 monthly energy production for all Dispatchable Plants located within the PSE BAA. The 10-minute interval datasets were created from base 1-minute interval data. The hour-ahead forecasts of PSE's BAA load were computed by summing together the original day-ahead forecasts and the next-hour load forecast adjustments.

**Q. Were 10-minute interval PSE BAA load, wind generation, or Dispatchable Plant forecasts available for calendar year 2010?**

A. No. In the WECC, outside of the California Independent System Operator BAA, power transfers between BAA operators are scheduled on an hourly basis. Therefore, PSE and most other entities that operate in the WECC utilize hourly forecasts of load and generation.

**Q. How did you convert the available hourly forecast data into 10-minute interval forecasts for calendar year 2010?**

A. The forecast quantity for each of the six 10-minute intervals in each hour was set equal to the hourly forecast value. I refer to these quantities as hourly levelized forecasts.

**Q. Were the hourly levelized load and generation forecasts adjusted to reflect the generation ramping that occurs at the beginning and end of each scheduling hour in the WECC?**

A. Yes. In order to avoid the problems that would occur if generating plants had to instantaneously change their dispatch points at the beginning of each scheduling hour, generating plants in the WECC ramp their output in a linear fashion during the last ten minutes of the current hour and the first 10 minutes of the next hour. When comparing a generating unit's actual output against the forecasted (i.e. prescheduled) value, it is

appropriate to include the ramping impact since this represents the "best available" within-the-hour generation forecast. Since the generating plants are ramping to match the hour-to-hour changes in load, it is also appropriate to create ramped load forecasts to represent best available load forecasts.

**Q. What was the end result of incorporating load and generation ramping effects into the base PSE hourly 2010 BAA load, wind generation, and dispatchable generation datasets?**

A. By incorporating the top-of-the-hour ramping impacts, a set of best available 10-minute interval PSE BAA load forecasts and a set of best available 10-minute interval PSE wind and dispatchable plant generation forecasts were created from the hourly levelized forecasts. These 10-minute interval load and 10-minute interval wind/dispatchable plant generation forecasts were then compared against the actual 10-minute load and wind/dispatchable plant generation values to compute: (1) 10-minute interval load deviations, (2) 10-minute interval wind generation deviations, and (3) 10-minute interval Dispatchable Plant generation deviations. Complete datasets of the hourly levelized forecasts and the hourly ramped forecasts for PSE's BAA load, the Wild Horse and Vantage wind plants, and the six representative Dispatchable Plants are contained in Tables 4, 5, and 6 of my confidential workpapers.

**Q. Please describe how the 10-minute PSE load deviation quantities were used in the first step of the Intermittent Purchase Obligation computation.**

A. The 10-minute interval PSE load forecast versus actual load deviations were computed using the calendar year 2010 data. This computation resulted in a total of 52,560 10-minute load forecast versus actual load deviation quantities. Then, the standard deviation

of this dataset was computed. Finally, multiplying the standard deviation by two, I established the 95% confidence interval: this resulted in a figure of 71.00 MW. In simple terms this means PSE, over the course of the year and on a stand-alone basis, needs 71.00 MW of flexible and quick reacting capacity available to be 95% confident of meeting its BAA obligation to manage within-hour load variations. Details regarding the computation of the stand-alone BAA load regulation requirement are contained in Table 7 of my confidential workpapers.

**Q. Why did you choose to use a 95% confidence interval?**

A. The 95% confidence interval was chosen as a reasonable balance between: (1) using a highly conservative measure so that PSE would be assured of meeting virtually all within-the-hour BAA load variations, i.e. a probability approaching 100%, and (2) ensuring that PSE can continue to meet the NERC CPS2 reliability criteria which is based upon a 90% performance metric. Using a 95% confidence interval for determining the expected value of the Regulation Capacity required to manage within-the-hour variations in PSE's BAA load is reasonable given that using a lower confidence interval would likely: (1) degrade PSE's CPS2 performance, and/or (2) would result in PSE absorbing additional costs not recovered through Schedule 13 in order for it to continue to meet the CPS2 criteria. However, as PSE gains more experience in managing increasing amounts of wind generation variability in its BAA under various system operating conditions, use of a confidence interval greater than 95% may be necessary in order for PSE to continue to meet NERC reliability criteria.

**Q. Is the use of a 95% confidence interval consistent with *Westar*?**

A. Yes. Westar's Schedule 3A regulation tariff that was recently approved by the Commission also incorporated a 95% confidence interval for the determination of the applicable regulation allocation factors. I note, however, that at least one other provider of within-the-hour wind regulation services utilizes a confidence interval greater than 95%: BPA's current Wind Integration Tariff (pursuant to which PSE itself purchases wind balancing services for its Hopkins Ridge and Klondike III wind plants) incorporates a 99.5% confidence interval. I note that PSE's Schedule 13 Intermittent Purchase Obligation would be 50% higher than the proposed figure if PSE chose to utilize the same 99.5% confidence interval as is currently being utilized by BPA.

**Q. Please describe the second step of the Intermittent Purchase Obligation computation.**

A. In the second step of the Intermittent Purchase Obligation computation, the10-minute Wild Horse forecast versus actual generation deviations and the 10-minute Vantage plant forecast versus actual generation deviations were computed using calendar year 2010 data. For the Vantage plant, only data for the time period that the plant was in commercial operation (October 4, 2010 – December 31, 2010) was used in the determination of the Intermittent Purchase Obligation. The next-hour forecasts for both the Wild Horse and Vantage wind plants were persistence-based forecasts that were developed by using the actual average generation value for the first minute of hour t as the levelized generation forecast for hour t + 1 (i.e. a 60-minute before the hour persistence forecast). This computation resulted in a total of 52,560 10-minute interval forecast versus actual generation deviation quantities for Wild Horse plant and 12,816 10-minute deviations for the Vantage plant. Next, the 10-minute forecast versus actual

deviations for the two wind plants were combined, and the standard deviation of the combined dataset was computed. Finally, using two times the standard deviation I established the 95% confidence interval: this resulted in a figure of 77.80 MW. Details regarding the computation of the stand-alone wind plant regulation requirement are contained in Table 8 of my confidential workpapers.

**Q. What does the 77.80 MW figure you refer to above represent?**

A. The 77.80 MW figure represents the expected stand-alone amount of within-the-hour variation of the combined generation output of the Wild Horse and Vantage wind plants within a 95% confidence interval. This figure represents the amount of within-the-hour Regulation Capacity that PSE would need to maintain in order to manage wind generation variability operating *in isolation* from the rest of its system. This figure does not incorporate PSE load variations or Dispatchable Plant variations; therefore potential system diversity is not reflected in this figure. Without incorporating these system diversity benefits, the stand-alone Intermittent Purchase Obligation would be 26.25%.

**Q. Please describe the third step of the Intermittent Purchase Obligation computation.**

A. In the third step of the Intermittent Purchase Obligation computation, the 10-minute Dispatchable Plant forecast versus actual generation deviations were computed for all of the calendar year 2010 data. The purpose of this calculation is to determine the amount of system variability attributable to PSE's dispatchable generation resources in order to perform the portfolio-wide analysis described in step five, *infra*. Unlike Westar's situation, PSE does not receive dispatch instructions from a power pool or other third party. Therefore, PSE cannot determine the regulation requirement of its dispatchable generating plants in the exact same fashion as Westar did in their recent Schedule 3A

filing since the dispatch instruction data – which in Westar's case represented the forecast for each dispatchable plant under the SPP's control for the upcoming 10-minute interval – is simply not available in PSE's case. I therefore employed a different methodology to create hour-ahead forecasts for PSE's Dispatchable Plants that was based upon the available data. As detailed below, this methodology reasonably replicates Westar's approach using the best data currently available to PSE.

**Q: Please describe the methodology that you utilized to determine the hourly scheduled versus actual deviations for PSE's Dispatchable Plants.**

A: First, I chose six plants from PSE's fleet of dispatchable generating resources to represent each of the three main categories of resource types that PSE operates: (1) the Colstrip 1&2 and Colstrip 3&4 plants were chosen to represent coal-fired steam plants, (2) the Goldendale and Sumas plants were chosen to represent natural gas-fueled CCCT/CT/misc thermal plants, and (3) the Upper Baker and Lower Baker plants were chosen to represent hydroelectric plants. Next, the operation of each of the six representative plants was analyzed across calendar year 2010 to determine the periods when the plant was operated in a steady-state mode. All hours in which the plant was: (1) not being intentionally ramped up or down, or (2) was not being limited by a partial or full unit forced outage were considered to be steady-state periods. Next, a set of 60-minute before-the-hour persistence forecasts were created for each representative plant. A cross-check was then performed to ensure that each 60-minute persistence forecast was determined at a point in time when the plant was operating in a steady-state mode. The hourly levelized forecasts created from the previous step were then ramped across the last 10 minutes of each hour and the first 10 minutes of the next hour in order to be consistent

with the top of the hour ramping procedure used in the WECC. Finally, the difference between the hour-ahead ramped forecasts and the actual generation for each representative plant were computed across each 10-minute period for all of the steady-state hours for that particular plant during calendar year 2010. Complete datasets of the hourly levelized forecasts and the hourly ramped forecasts for the six representative Dispatchable Plants are contained in Table 6 of my confidential workpapers. Details regarding the identification of the steady-state operating periods for each representative Dispatchable Plant are contained in Tables 9a-c of my confidential workpapers.

**Q: Is it reasonable to utilize a 60-minute in advance of the hour persistence forecast in order to determine the within-the-hour variability of PSE's representative Dispatchable Plants?**

A: Yes. As I previously mentioned, PSE does not receive dispatch instruction from a power pool or other third party that could be used to determine each generator's next-hour schedule. Also, while PSE creates and maintains day-ahead schedules for all of its dispatchable generating plants, PSE does not create and maintain a complete set of revised, hour-ahead schedules in real-time. Using 60 minute before the hour persistence forecasts for PSE's dispatchable plants is therefore a reasonable approach to determine the expected next-hour generation level from each plant during steady-state operating periods.

**Q: Is the use of 60-minute before-the-hour persistence forecasts to determine the regulation requirement of PSE's dispatchable generating plants consistent with how you determined the scheduled versus actual deviations of the wind plants located within the PSE BAA?**

A: Yes. I determined the within-the-hour regulation requirement of the wind plants located within the PSE BAA by comparing 60-minute in advance of the hour persistence forecasts against the actual wind generation that occurred within each 10-minute period during that same hour. The methodologies for determining the within-the-hour regulation requirement of PSE's Dispatchable Plants and the wind plants located within PSE's BAA are therefore consistent.

**Q: Is it reasonable to exclude the hours on which there was an intentional ramping operation on a plant from the computation of the scheduled versus actual generation deviations for the six representative PSE Dispatchable Plants?**

A: Yes. The intent of the computation described above is to quantify the random fluctuations between a representative Dispatchable Plant's expected operation – as measured via a 60-minute before the hour persistence forecast – and its actual operation. Deviations resulting from a dispatchable plant being *intentionally* ramped up or down within an hour while under PSE's operational control are obviously not random in nature and such "deviations" should not be considered when determining the within-the-hour regulation requirement of the representative Dispatchable Plants.

**Q: Is it reasonable to exclude the hours on which there were partial or full forced outages on a plant from the computation of the scheduled versus actual generation deviations for the six representative PSE Dispatchable Plants?**

A: Yes. The intent of the forecast versus actual deviation computation is to quantify the within-the-hour regulation requirement of PSE's Dispatchable Plants. In addition to maintaining regulation capacity reserves, PSE also maintains a separate pool of contingency capacity reserves that are available to respond to partial or full forced

outages on its thermal and/or hydroelectric plants. Therefore, if one of the representative Dispatchable Plants suffers a partial or full forced outage, such an event could be covered by PSE's contingency capacity reserves and not PSE's regulation reserves.

**Q: How were the forecast versus actual generation deviations of the six representative PSE Dispatchable Plants used to determine the overall variability of all of PSE's Dispatchable Plants?**

A: The 10-minute interval scheduled versus actual deviations as measured across all of the steady-state hours during each month of calendar year 2010 were scaled up by the ratio of the total amount of monthly energy production from all Dispatchable Plants within that class (coal-fired steam, CCCT/CT/Misc, or hydro) that were electrically located within the PSE BAA, divided by the total monthly energy production of the two representative Dispatchable Plants. The scaled up 10-minute deviations for all three of the PSE plant classes were then combined with the 10-minute PSE load deviations and the 10-minute wind deviations in order to determine PSE's overall within-the-hour regulation requirement. Details regarding the computation of the coal-fired steam plant, CCCT/CT/Misc plant, and hydro plant scaling factors are contained in Table 10 of my confidential workpapers.

**Q. What were the results from Step 3 of the Intermittent Purchase Obligation computation regarding the schedule versus actual deviations for PSE's Dispatchable Plants?**

A. Prior to the applying the scaling-up process, the 95% confidence figures for the six representative Dispatchable Plants were as follows: (1) Colstrip 1&2 – 6.07 MW, (2) Colstrip 3&4 – 5.04 MW, (3) Goldendale – 2.53 MW, (4) Sumas – 1.11 MW, (5) Upper

Baker – 0.42 MW, and (6) Lower Baker – 1.14 MW. After applying the scaling factors, the results for the three classes of PSE plants were: (1) Coal-Fired Steam plants – 8.53 MW, (2) Gas/Oil-Fired CCCT/CT/Misc plants – 7.53 MW, and (3) Hydroelectric plants 1.99 MW. Details regarding the computation of the stand-alone regulation requirements for each of the six representative plants are contained in Tables 9a-c of my confidential workpapers. Details regarding the application of the scaling factors in order to determine the stand-alone regulation requirement of each of the three plant classes are contained in Table 11 of my confidential workpapers.

**Q. What do the 8.53 MW, 7.53 MW, and 1.99 MW figures you refer to above represent?**

A. These three MW figures represent the stand-alone amounts of the within-the-hour Regulation Capacity that PSE must maintain within its BAA in order to manage the within-the-hour forecasted versus actual generation deviations of each of its three classes of Dispatchable Plants with a 95% confidence.

**Q. What is the fourth step in the determination of the Intermittent Purchase Obligation?**

A. In the fourth step of the Intermittent Purchase Obligation computation, I determined the calendar year 2010 total within-the-hour regulation requirement of the combination of the PSE load deviations, the wind plant generation deviations, and the Dispatchable Plant generation deviations using a 95% confidence interval.

**Q. Are the 95% confidence regulation figures that you previously computed in Steps 1-3 of the Intermittent Purchase Obligation computation for PSE's load, wind generation, and dispatchable generation directly additive?**

A. No. Adding the regulation requirements that were determined in Steps 1-3, which were computed on a stand-alone basis, would fail to take into account system diversity impacts. In other words, because the 10-minute load, wind generation, and dispatchable plant generation deviations are sometimes offsetting, simply adding the individual 95% confidence figures would overstate the combined impacts of all the sources of deviation. For instance, if a particular 10-minute wind generation deviation was a positive 20 MW and the Dispatchable Plant generation deviation during the same interval was negative 5 MW, the net regulation requirement for all generating plants during that interval would be only positive 15 MW.

**Q. How did you determine the overall within-the-hour regulation requirement of the PSE system?**

A. Using the same set of 10-minute deviations that were determined in Steps 1-3, I first determined the variance of each of the five elements that are included in the Regulation study. The five elements included in the study are: (1) PSE load deviations, (2) PSE wind generation deviations, (3) PSE coal-fired thermal plant generation deviations, (4) PSE CCCT/CT/Misc plant generation deviations, and (5) PSE hydroelectric plant generation deviations. Next, I determined the covariance between each pair of the five elements during the steady-state periods common to each element pair. Then I added the variance for each individual element together with the covariances between that element and the other four elements to determine the Adjusted Variance for each element. The 95% confidence regulation requirement for the combination of all five elements was then determined by summing the five Adjusted Variance figures, taking the square root, and multiplying by two. The result of this computation was 106.27 MW, which represents the

overall calendar year 2010 within-the-hour regulation requirement of the PSE system. The following table illustrates this set of computations:

| | Individual Std Dev (MW) | Covariance with PSE Load (MW) | Covariance with Wind Plants (MW) | Covariance with Coal Plants (MW) | Covariance with Hydro Plants (MW) | Covariance with CCCT/ CT/Misc (MW) | Adjusted Variance |
|---|---|---|---|---|---|---|---|
| PSE BAA Load | 35.50 | | 8.36 | 1.29 | (0.99) | (2.57) | 1,266.4 |
| Wind Plants | 38.90 | 8.36 | | (0.27) | 0.25 | 1.27 | 1,522.8 |
| Coal-Fired Steam Plants | 4.27 | 1.29 | (0.27) | | 0.09 | 0.58 | 19.9 |
| Hydro Plants | 0.99 | (0.99) | 0.25 | 0.09 | | 0.08 | 0.4 |
| CCCT/CT/Misc Plants | 3.77 | (2.57) | 1.27 | 0.58 | 0.08 | | 13.5 |
| | | | | | Total Adjusted Variance | | 2,823.1 |
| | | | | | Total 2*Standard Deviation | | 106.27 |

**Q. Does the 106.27 MW figure incorporate the diversity between variations in PSE's BAA load, wind generation, and dispatchable generation located within the PSE BAA?**

A. Yes. Diversity impacts between load, wind generation, and dispatchable generation deviations within the PSE BAA reduced the overall 95% confidence within-the-hour regulation requirement by approximately 36%, as compared to the sum of the stand-alone regulation requirements.

**Q. What is the fifth step in determining the Intermittent Purchase Obligation?**

A. The fifth step in the Intermittent Purchase Obligation computation is to allocate a portion of the overall system diversity benefit to the wind plants located within the PSE BAA, thereby reducing the within-the-hour wind plant regulation requirement. The initial step in this process is to determine the PSE system diversity benefit ratio. This ratio is computed by calculating the 95% confidence value for the combination of the five elements (which is the square root of the sum of the five Adjusted Variances, multiplied by two) and then dividing by the sum of the 95% confidence value for each of the individual five elements in the regulation study (which is the square root of each

element's Adjusted Variance multiplied by two. The result of this computation is 0.637, which is the PSE system diversity ratio. To determine the within-the-hour regulation requirement of the wind plants located within the PSE BAA, the 95% confidence value for the wind plants (which is the square root of the wind plants'Adjusted Variance multiplied by two) is multiplied by the system diversity ratio, which results in a final within-the-hour wind regulation requirement of 49.72 MW. The following table shows the Step 5 results.

| | Regulation Allocation (MW) | Regulation Allocation (%) |
|---|---|---|
| PSE BAA Load | 45.34 | |
| Wind Plants | 49.72 | 16.77 |
| Coal-Fired Steam Plants | 5.68 | |
| Hydro Plants | 0.83 | |
| CCCT/CT/Misc Plants | 4.69 | |
| **Total Regulation Requirement** | **106.27** | |

**Q. What is the sixth and final step in the Intermittent Purchase Obligation determination?**

A. The wind plant within-the-hour regulation requirement determined in Step 5 is divided by the total installed capacity of all of the wind plants located within the PSE BAA for which PSE is providing regulation service in order to determine the Intermittent Purchase Obligation. This computation results in an Intermittent Purchase Obligation of 16.77% (49.72 MW wind regulation requirement divided by 296.41 MW of installed wind plant capacity). The 296.41 MW installed capacity figure was pro-rated across calendar year 2010 to reflect the fact that the 96 MW Vantage Plant was in commercial operation only during the period October 4, 2010 – December 31, 2010. Therefore, given calendar year

2010 historical data, PSE would need to maintain wind plant regulation reserves in the amount of 16.77% of the total installed wind capacity located within the PSE BAA in order to manage the within-the-hour wind generation deviations with a 95% confidence. The complete 10-minute interval detail of the Intermittent Purchase Obligation computation is contained in Table 12 of my confidential workpapers.

**Q. Did the portfolio wide approach significantly reduce the Schedule 13 purchase obligation of wind and other intermittent generation resources?**

A. Yes. Giving wind generators the full benefit of offsetting system diversity resulted in a 36% reduction in the Intermittent Purchase Obligation.

**Q: Is the methodology that you employed to determine overall system diversity benefits in the computation of the Schedule 13 Intermittent Purchase Obligation consistent with the methodologies employed in *Westar*?**

A: Yes. The methodology by which I determined system diversity impacts between the five elements in the PSE regulation study and the method by which I allocated a portion of the system diversity benefit to wind plants located within the PSE BAA is consistent with the approach that the Commission previously approved in *Westar*. I note that while the Westar regulation studies used a slightly different categorization of the sources of deviations than the PSE studies, the two sets of studies are consistent in how system diversity impacts were determined and how those benefits were allocated between the different sources of deviation.

**Q: Do you believe that the 16.77% regulation percentage as determined above for wind and other non-dispatchable plants located within the PSE BAA is a conservative**

**measure of the amount of flexible capacity that PSE must reserve in order to manage within-the-hour intermittent plant deviations?**

A: Yes. I believe that the 16.77% Intermittent Purchase Obligation, which was developed pursuant to the general methodology that the Commission approved in *Westar,* likely understates the full range of incremental and decremental capacity that PSE must maintain in order to manage within-the-hour wind generation deviations with a 95% confidence.

**Q: Please explain.**

A: In my experience in developing day-ahead load forecasts for the PSE system across a 9 year period, I have observed that both the direction and relative magnitude of load ramps on the PSE system are generally predictable to a high degree of accuracy. For instance, on weekdays, the PSE system would experience a rapid upward load ramp during scheduling hours 0600 and 0700 that would require that PSE maintain incremental capacity reserves – but virtually no decremental capacity reserves – in order to manage the load pickup across these hours. Likewise, on scheduling hours 2200 and 2300 PSE's loads tend to decrease rapidly, which requires PSE to maintain decremental capacity reserves - but virtually no incremental capacity reserves – across these hours.

**Q: Do changes in wind plant generation within the PSE BAA follow the same basic ramping patterns as what is observed for PSE's loads?**

A: No. Wind plant ramping events on the PSE system are much more difficult to predict than PSE's load ramping events. Also, the *direction* of wind generation ramping events is more uncertain than the direction of load ramping events. In addition, PSE has experienced wind ramping events in both directions during the same hour. This inherent

characteristic of wind generation means that PSE must maintain both incremental *and* decremental capacity reserves during many hours in order to manage wind plant generation that could ramp unexpectedly in *either* direction.

**Q: Does the methodology accepted by the Commission in *Westar* fully account for both the incremental and decremental capacity requirements that PSE must maintain in order to manage generation deviations from wind plants located within its BAA with a 95% confidence?**

A: In my opinion, the methodology accepted by the Commission in *Westar*, while reasonable in many respects, does not fully account for the fact that wind generation ramping events are more unpredictable than load ramping events. By multiplying the standard deviation of the forecast versus actual wind deviations by 2 (instead of 4), the *Westar* methodology understates the total range of flexible capacity – both incremental and decremental capacity – that a BAA operator is required to maintain under actual operating conditions in order to manage wind ramping events (which could occur in either direction) with a 95% confidence. The Commission's recent Notice of Proposed Rulemaking on Frequency Regulation in Organized Markets recognizes this principle.[2]

**Q. What is the significance of this observation?**

A. I make this observation only to highlight that, by following the "divide-by-two" approach approved by the Commission in Westar, PSE has elected to take a conservative approach to cost recovery under Schedule 13.

## SECTION IV– DETERMINATION OF THE SCHEDULE 13 CHARGE FOR REGULATION AND FREQUENCY RESPONSE SERVICE

[2] *Frequency Regulation Compensation in Organized Wholesale Power Markets*, Notice of Proposed Rulemaking, 76 Fed. Reg. 11,177 (Mar. 1, 2011), 134 FERC ¶ 61,124 (2011).

**Q. How are a transmission customer's charges under PSE's Schedule 13 determined?**

A. As demonstrated in Statement BL, which I support and sponsor, and which is attached to my testimony as Exhibit PSE-101, a transmission customer's charges under PSE's Schedule 13 are determined via three billing determinants: (1) the customer's reserved transmission amount, (2) the purchase obligation, and (3) the capacity rate.

**Q. Please describe the capacity rate component of PSE's Schedule 13.**

A. The capacity rate represents PSE's capacity-related costs of providing within-the-hour regulation and frequency response service under both OATT Schedules 3 and 13. This rate, as determined in the testimony of Mr. Story, is $12.39 per Kilowatt-month. This figure was derived from the capacity-related costs of the pool of existing PSE generating units that are capable of supplying within-the-hour regulation and frequency response capacity as described in the testimony of Mr. Tongue.

Q. **How was the Schedule 13 capacity rate of $12.39 / kW-month determined?**

A. The $12.39 / kW-month capacity rate was determined via a plant capacity-weighted cost computation; the details of this computation are contained in Exhibit PSE-501, Period II Statement BK– By Plant. I note that the capacity figures used in Statement BK – By Plant are representative of the actual amount of regulating capacity that each resource is capable of providing.[3]

**Q. Please describe the purchase obligation component of PSE's Schedule 13.**

[3] The plant capacity figures cited in Statement BK – By Plant (Exhibit PSE-501)were taken directly from PSE's 2010 FERC Form 1 Report. Capacity figures for the PSE thermal plants are the "Net Continuous Plant Capability When Not Limited by Condenser Water" ratings. Capacity figures for the PSE hydro plants are the "Net Plant Capability Under Most Favorable Oper[ating] Conditions" ratings.

A. The purchase obligation is a percentage quantity that is determined based upon the type of generating resource for which PSE is providing regulation and frequency response service. For wind plants (and other intermittent, non-dispatchable generating resources such as solar) the purchase obligation is 16.77%; the derivation of this percentage was previously described in Section III of my testimony. For all non-wind and non-intermittent generating resources, which I collectively refer to as Dispatchable Resources, the purchase obligation is 2.00%.

**Q. How is the monthly charge for regulation and frequency response service supplied by PSE to exporting wind resources under Schedule 13 determined?**

A. An exporting wind plant's monthly charge for regulation and frequency response service under Schedule 13 is computed by multiplying the transmission customer's reserved transmission capacity times a purchase obligation of 16.77% times the capacity rate. For example, a customer that has reserved 100,000 kW of transmission and who is exporting capacity and energy from a wind resource out of the PSE BAA would be assessed a monthly charge under Schedule 13 as follows:

100,000 kW * 16.77% * $12.39 / kW-month = $207,780 per month

**Q. How is the monthly charge for regulation and frequency response service supplied by PSE to exporting Dispatchable Resources under Schedule 13 determined?**

A. An exporting Dispatchable Resource's monthly charge for regulation and frequency response service under Schedule 13 is computed by multiplying the transmission customer's reserved transmission capacity times a purchase obligation of 2.00% times the capacity rate. For example, a customer that has reserved 100,000 kW of transmission and

who is exporting capacity and energy from a dispatchable resource out of the PSE BAA would be assessed a monthly charge under Schedule 13 as follows:

100,000 kW * 2.00% * $12.39 / kW-month = $24,780 per month

**Q. How do the charges assessed to exporting wind plants for regulation and frequency response service under PSE's Schedule 13 compare with the charges assessed by BPA pursuant to its within-the-hour Wind Balancing Service?**

A. BPA's Wind Balancing Service, as recently implemented by BPA as part of its 2010 transmission rate case, is similar to PSE's Schedule 13 in that both tariffs strive to recover the additional costs beyond the energy costs recovered in Schedule 9 for Generator Imbalance service associated with managing within-the-hour wind generation variations. However, the two rates are not directly comparable due to significant differences in the quality of the regulation service being provided. BPA's originally proposed Wind Balancing Service rate, for a within-the-hour wind regulation product of similar quality to that being provided by PSE under Schedule 13, was $2.72 / kW-month. After holding a series of discussions with its customers, BPA agreed to reduce its final Wind Balancing Services rate to between $1.29/kW-month and $1.58/kW-month. The comparable rate assessed to exporting wind plants under PSE's updated Schedule 13 would be approximately $2.08 / kW-month (equal to the capacity cost of $12.39/kW-month times the 16.77% purchase obligation). However, in exchange for agreeing to a lower Wind Balancing Rate, BPA gained the ability to significantly limit in real-time the amount of within-the-hour regulating capacity that it makes available to existing and new wind plants located within its BAA. Once BPA reaches this regulating capacity cap, wind plants in the BPA BAA must follow BPA dispatch instructions to curtail their generation

output. In addition, as part of its ongoing FY2012 transmission rate case process, BPA has presented proposals that would: 1) restrict the amount of regulation capacity that BPA makes available on a long-term basis to existing and new wind plants located within its BAA, and 2) have BPA charge higher rates for wind balancing services that have lower probabilities of curtailments and/or limitations.

**Q. Is PSE proposing under Schedule 13 to limit the amount of regulation and frequency response capacity that it makes available to existing and/or new wind plants located within its BAA?**

A. No. Unlike BPA, PSE is not proposing to limit the amount of regulation and frequency response capacity that it provides to either existing or new wind plants located within its BAA, except to the extent required to maintain system reliability pursuant to WECC and NERC reliability criteria.

**Q. Does this conclude your testimony?**

A. Yes.

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

| | | |
|---|---|---|
| **Puget Sound Energy, Inc.** | ) | **Docket No. ER11-___-000** |

**AFFIDAVIT OF LLOYD C. REED**

Lloyd C. Reed, being first duly sworn, deposes and states that he is the Lloyd C. Reed referred to in the document entitled "Prepared Direct Testimony of Lloyd C. Reed on Behalf of Puget Sound Energy, Inc.," that any exhibits accompanying that document were prepared by him or under his direction, that he has read such testimony and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information and belief in this proceeding.

Lloyd C. Reed

SUBSCRIBED AND SWORN TO before me, the undersigned notary public, this ___ day of May, 2011.

Notary Public

My Commission Expires: My Commission Expires March 31, 2014

SHAWNNA WATSON NOTARY PUBLIC STATE OF COLORADO

**Statement BL - Period I**
**Puget Sound Energy**
**Rate Design Information**

**Charges for Regulation and Frequency Response Service Under Schedule 3**

A transmission customer's charges for purchasing Regulation and Frequency Response Service under Schedule 3 are computed based upon the following billing determinates: 1) the customer's reserved capacity for Point to Point Transmission Service or Network Integration Transmission Service, 2) the purchase obligation, and 3) the capacity cost.

The purchase obligation is 2.00%. This percentage remains unchanged from the currently-in-effect Schedule 3.

The capacity cost, as derived in Statement BK by Plant, is $11.67/KW-month. This cost has been updated to reflect PSE's current cost of providing Regulation and Frequency Response Service.

The monthly charge for a transmission customer with a 100,000 KW transmission reservation that is purchasing Regulation and Frequency Response Service under Schedule 3 is determined as follows:

Monthly Schedule 3 Charge = 100,000 KW * 2.00% * $11.67/KW-month = $23,340

**Statement BL - Period I**
**Puget Sound Energy**
**Rate Design Information**

**2) Charges for Regulation and Frequency Response Service Under Schedule 13**

A transmission customer's charges for purchasing Regulation and Frequency Response Service under Schedule 13 are computed based upon the following billing determinates: 1) the customer's reserved capacity for Point to Point Transmission Service or or Network Integration Transmission Service, 2) the purchase obligation, and 3) the capacity cost.

The purchase obligation for dispatchable generating resources that are delivering energy outside of the PSE control area is 2.00%. This percentage remains unchanged from the currently-in-effect Schedule 13.

The purchase obligation for wind plants and/or other intermittent generating resources that are delivering energy outside of the PSE control area is 16.77%. This percentage, as derived in the testimony of Mr. Lloyd Reed, reflects the additional amount regulating capacity that PSE must maintain in order to manage the within-the-hour generation deviations of wind plants and/or other intermittent generating plants.

The capacity cost, as derived in Statement BK by Plant, is $11.67/KW-month. This cost has been updated to reflect PSE's current cost of providing Regulation and Frequency Response Service.

The monthly charge for a transmission customer with a 100,000 KW transmission reservation that is purchasing Regulation and Frequency Response Service under Schedule 13 in order to export energy from a dispatchable generating resource is determined as follows:

Monthly Schedule 13 Charge = 100,000 KW * 2.00% * $11.67/KW-month = $23,340

The monthly charge for a transmission customer with a 100,000 KW transmission reservation that is purchasing Regulation and Frequency Response Service under Schedule 13 in order to export energy from a wind plant and/or other intermittent generating resource is determined as follows:

Monthly Schedule 13 Charge = 100,000 KW * 16.77% * $11.67/KW-month = $195,705

**Statement BL - Period II**
**Puget Sound Energy**
**Rate Design Information**

**1) Charges for Regulation and Frequency Response Service Under Schedule 3**

A transmission customer's charges for purchasing Regulation and Frequency Response Service under Schedule 3 are computed based upon the following billing determinates: 1) the customer's reserved capacity for Point to Point Transmission Service or Network Integration Transmission Service, 2) the purchase obligation, and 3) the capacity cost.

The purchase obligation is 2.00%. This percentage remains unchanged from the currently-in-effect Schedule 3.

The capacity cost, as derived in Statement BK by Plant, is $12.39/KW-month. This cost has been updated to reflect PSE's current cost of providing Regulation and Frequency Response Service.

The monthly charge for a transmission customer with a 100,000 KW transmission reservation that is purchasing Regulation and Frequency Response Service under Schedule 3 is determined as follows:

Monthly Schedule 3 Charge = 100,000 KW * 2.00% * $12.39/KW-month = $24,780

**Statement BL - Period II**
**Puget Sound Energy**
**Rate Design Information**

**2) Charges for Regulation and Frequency Response Service Under Schedule 13**

A transmission customer's charges for purchasing Regulation and Frequency Response Service under Schedule 13 are computed based upon the following billing determinates: 1) the customer's reserved capacity for Point to Point Transmission Service or or Network Integration Transmission Service, 2) the purchase obligation, and 3) the capacity cost.

The purchase obligation for dispatchable generating resources that are delivering energy outside of the PSE control area is 2.00%. This percentage remains unchanged from the currently-in-effect Schedule 13.

The purchase obligation for wind plants and/or other intermittent generating resources that are delivering energy outside of the PSE control area is 16.77%. This percentage, as derived in the testimony of Mr. Lloyd Reed, reflects the additional amount regulating capacity that PSE must maintain in order to manage the within-the-hour generation deviations of wind plants and/or other intermittent generating plants.

The capacity cost, as derived in Statement BK by Plant, is $12.39/KW-month. This cost has been updated to reflect PSE's current cost of providing Regulation and Frequency Response Service.

The monthly charge for a transmission customer with a 100,000 KW transmission reservation that is purchasing Regulation and Frequency Response Service under Schedule 13 in order to export energy from a dispatchable generating resource is determined as follows:

Monthly Schedule 13 Charge = 100,000 KW * 2.00% * $12.39/KW-month = $24,780

The monthly charge for a transmission customer with a 100,000 KW transmission reservation that is purchasing Regulation and Frequency Response Service under Schedule 13 in order to export energy from a wind plant and/or other intermittent generating resource is determined as follows:

Monthly Schedule 13 Charge = 100,000 KW * 16.77% * $12.39/KW-month = $207,780