EXHIBIT NO. ___(MDR-1CT)
DOCKET NO. UE-13____
2013 PSE PCORC
WITNESS: MATTHEW D. RARITY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-13____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF MATTHEW D. RARITY ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

APRIL 25, 2013

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF MATTHEW D. RARITY

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF MATTHEW D. RARITY

I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is Matthew D. Rarity. My business address is 10885 NE Fourth Street, P.O. Box 97034, Bellevue, WA 98009-9734. I am Manager, Power and Gas Supply Operations for Puget Sound Energy ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(MDR-2).

Q. Please explain your duties as Manager, Power and Gas Supply Operations for PSE.

A. As Manager, Power and Gas Supply Operations, I am responsible for oversight of PSE's short-term (real-time, day-ahead, and balance of month) trading and scheduling activities and ensuring reliable and cost-effective operations including the optimization of excess capacity, energy, and operational flexibility. Previously, I was Manager of the Renewable Resources Integration team at PSE. In that role, I was responsible for the oversight of PSE's wind integration analytics, including balancing reserve requirements, balancing reserve optimization, wind integration cost analysis, wind integration policy, and ad-hoc power system analytics.

Q. Please summarize your prefiled direct testimony.

A. This prefiled direct testimony focuses on the nature of integrating wind resources into the electric system (i.e., the inherent challenges presented by wind generation, the means by which PSE quantifies and addresses the volatility associated with wind, and how PSE models the costs of wind integration). PSE has leveraged its experience with, and knowledge of, wind generation to support the need for wind integration services and the recovery of costs to integrate wind resources.

Specifically, this prefiled direct testimony addresses the following issues relevant to the wind integration costs for this proceeding's rate year, November 1, 2013 through October 31, 2014 ("rate year"):

1) Definition of wind integration issues, operational constraints and resulting costs;

2) PSE's experience, analytics and forecast of wind generation and renewable resource integration costs; and

3) Notable adjustments to PSE modeling methodologies.

Q. What is the impetus for this exposition of wind integration modeling?

A. In Docket Nos. UE-111048 and UG-111049 (the "2011 GRC"), the Commission acknowledged the real costs[1] associated with integrating variable energy resources and requested that PSE, in future cases, "present more detail concerning

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[1] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-111048 & UG-111049, Order 08 at ¶ 249 (2012) ("The highly variable nature of the resource and the industry's lack of experience in integrating such a resource pose physical and financial challenges for the industry and for regulatory authorities, including in this region the Bonneville Power Association and the state regulatory Commissions.")

the historical data and modeling upon which [PSE] forecast of wind integration costs depend".[2] This prefiled direct testimony discusses PSE's use of historical data and PSE's activities to understand, calculate, model, and utilize industry standards to determine the impact of wind volatility on balancing reserve requirements and system operations and costs.

II. WIND RESOURCES

Q. Please describe PSE's wind resources.

A. PSE has nearly 822 megawatt ("MW") of wind. PSE currently owns several wind projects:

1) Hopkins Ridge Wind Project ("Hopkins Ridge"), located in southeast Washington near the town of Dayton, has 87 Vestas V80 wind turbines and an electrical capacity of 156.6 MW.[3] Hopkins Ridge is located in the Bonneville Power Administration ("BPA") Balancing Authority Area ("BAA").

2) Wild Horse Wind Project ("Wild Horse"), located in central Washington near Ellensburg, has 127 Vestas V80 turbines and an electrical capacity of 228.6 MW.[4] Wild Horse is in PSE's BAA.

3) Wild Horse Expansion Wind Project ("Wild Horse Expansion"), located in central Washington has 22 Vestas V80 turbines and an electrical capacity of 44 MW.[5] Wild Horse Expansion is in PSE's BAA.

4) Phase 1 of the Lower Snake River Wind Project ("LSR Phase 1"), located in Pomeroy, Garfield County has 149

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[2] *Id*. at ¶ 253.

[3] The 156.6 MW capacity includes the Hopkins Ridge Infill 7.2 MW capacity from the additional four turbines that went into service August 2008. The original 83 Hopkins Ridge turbines were placed in service November 27, 2005.

[4] Wild Horse was placed in service on December 22, 2006.

[5] Wild Horse Expansion project was placed in service on November 9, 2009.

turbines and an electrical capacity of 342.7 MW.[6] LSR Phase 1 is in BPA's BAA.

Additionally, PSE has a long-term power purchase agreement ("PPA") with Klondike Wind Power III, LLC, an affiliate of Iberdrola Renewables, Inc. ("Iberdrola Renewables"), for 22.36 percent of the output of the Klondike III Wind Project ("Klondike III") located in the Lower Columbia River Gorge region.

Table 1 below provides a summary of PSE's expected rate year wind generation capacity:

Table 1. PSE's Wind Generation Capacity

	Capacity (MW)	# Turbines
Hopkins Ridge	156.6	87
Wild Horse	228.6	127
Wild Horse Expansion	44.0	22
LSR Phase 1	342.7	149
Klondike III PPA	50.0	N/A
Total	**821.9**	**385**

Q. Please explain the volatility of wind generation.

A. PSE's power portfolio benefits from approximately 822 MW of wind generation capacity. Wind resources, however, present several challenges when integrating their generation into the PSE system. Such challenges (collectively known as volatility) can broadly be broken into two categories:

1.) <u>Uncertainty</u>: Uncertainty is the forecast error associated with wind generation. PSE expects a given level of generation for an hour based on the best forecast at the time; the actual generation, however, can be quite different.

[6] LSR Phase 1 was placed into service on February 29, 2012.

2.) Variability: Variability is the moment-to-moment, minute-to-minute fluctuations in wind generation from the forecasted, or expected, level of generation.

It is important to note that although improved forecasting can reduce and possibly eliminate uncertainty, variability will always be present. PSE transacts in an hourly market, and even with a perfect forecast of average hourly wind generation, the minute-to-minute generation will still naturally deviate from the hourly value.

Q. How does PSE deal with wind volatility when providing power to customers?

A. PSE must manage wind volatility by reshaping its contracted Mid-Columbia ("Mid-C") hydro generation, utilizing other PSE generating assets within its system, and engaging in market transactions. The costs associated with these activities—termed wind integration costs—are discussed in more detail below.

III. WIND INTEGRATION COSTS

A. Wind Integration Overview

Q. Does the integration of wind present any unique challenges for PSE?

A. Yes. Wind generation is an intermittent and non-dispatchable generating resource. Although the volatility associated with wind generation can be managed in a manner similar to managing PSE's load, the variable nature of wind generation and current state of wind forecasting creates additional system volatility. Consequently, there can be large differences between the wind generation forecast and actual generation, and even between wind forecasts across different time horizons.

These large, short-term, unanticipated changes (up or down) in generation present some of the greatest challenges for PSE operators to manage effectively and ensure compliance with electric system reliability standards. If actual real-time generation output diverges from the hourly scheduled wind output, PSE operators must rebalance the system by increasing or decreasing generation from the Mid-C and/or other PSE generating assets within PSE's system. To ensure PSE has sufficient ability to increase or decrease generation to balance its BAA's wind generation volatility, PSE must hold, or "reserve", an amount of resource capacity, also known as "balancing capacity." Capacity that is available to increase generation is referred to as "INC" balancing capacity, whereas capacity available to decrease generation is known as "DEC" balancing capacity. This capacity is held, or "committed" every hour, standing ready to be deployed as energy or displaced as energy to counterbalance deviations in wind generation.

Q. What are wind integration costs?

A. Generally, wind integration costs are equal to the opportunity costs of having to reserve capacity to balance wind generation. In essence, generation capacity that may have been dispatched but for the presence of wind is withheld from the energy market. Conversely, generation that would not have been dispatched, but for the presence of wind, may be committed into the market. PSE incurs these costs through management of its wind generation capacity and through contracts with BPA. Rate year power costs include day-ahead wind integration costs incurred for all PSE wind resources regardless of the BAA. Power costs also include Variable Energy Resource Balancing Service ("VERBS") capacity and

Generation Imbalance Service costs paid to BPA for Hopkins Ridge, LSR Phase 1, and a portion of Klondike III. Finally, power costs include the hour-ahead costs of balancing Wild Horse and Wild Horse Expansion

Q. What Balancing Authorities are responsible for integrating PSE wind?

A. Hopkins Ridge, LSR Phase 1, and Klondike III are in the BPA BAA, and BPA provides integration services to manage the variable output of these wind projects. Under these services, BPA delivers the hourly scheduled amount of wind generation to PSE's system by utilizing its own balancing reserves. BPA charges the VERBS and Generation Imbalance Service rate for these services. The VERBS rate reflects the embedded and variable costs BPA estimates that it will incur to provide balancing reserve capacity for variable resources. The Generation Imbalance Service rate reflects the costs incurred by BPA to deploy balancing capacity as energy to firm wind generation to the fixed hourly wind schedule submitted by PSE.

Wild Horse and Wild Horse Expansion are in the PSE BAA, and PSE provides integration services to manage the variable output of these wind projects. PSE manages the entirety of the volatility in Wild Horse and Wild Horse Expansion wind generation and, accordingly, incurs day-ahead and hour-ahead costs.

Q. Are BPA-related wind integration costs subject to change?

A. Yes, there is a possibility that BPA's wind integration costs will change during the course of this proceeding. As discussed in the Prefiled Direct Testimony of Mr. Tom A. DeBoer, Exhibit No. ___(TAD-1T), BPA is conducting a combined power and transmission rate proceeding to set new rates for fiscal years 2013-2014 (i.e., October 1, 2013, through September 30, 2015) (the "BP-14 Rate Case"). In its Initial Proposal in the BP-14 Rate Case, BPA proposed three different VERBS rates that varied depending on the wind scheduling practice elected by the wind generator. PSE's prefiled rate year power costs assume PSE elects the current scheduling practice, known as "uncommitted scheduling," which allows hourly wind scheduling that is not tied to any specific or predetermined forecasting methodology. This election has a proposed rate of $1.39 per kilowatt month ("/kW-mo").

Subsequent to the power costs being finalized for this filing, on April 5, 2013, PSE submitted its VERBS scheduling election to BPA, electing to schedule Hopkins Ridge and LSR Phase 1 at the "30/60 committed scheduling" level, which requires hourly wind scheduling equivalent to, or better than, a 30-minute persistence forecast. BP-14 Rate Case proposed VERBS rate for this scheduling election is $1.14/kW-mo, which, as noted below, reduces rate year power costs approximately $1.6 million. The VERBS rate, however, will not be final until the BPA Administrator's Final Record of Decision, expected in July 2013. PSE is proposing to update its wind integration costs during this proceeding to reflect the BP-14 Rate Case Record of Decision.

Q. What are the projected wind integration costs for the rate year?

A. As discussed in greater detail below, PSE expects to incur the following costs to integrate its renewable wind resources:

1) Projected day-ahead costs of $1.0 million for all wind projects, based on historical opportunity costs associated with changes in wind generation forecasts and market prices from the day-ahead to real-time periods.

2) Projected hour-ahead costs of $2.2 million for Wild Horse and Wild Horse Expansion, which reflects the costs PSE projects to incur to provide balancing reserve capacity prior to the operating hour to manage the volatility of Wild Horse and Wild Horse Expansion generation.

3) Projected BPA VERBS costs of $8.7 million based on maintaining the current VERBS scheduling practice, which reflect projected costs payable to BPA to provide hourly balancing capacity for Hopkins Ridge, LSR Phase 1 and Klondike III. On April 5, 2013 PSE submitted its VERBS scheduling election to BPA, resulting in a decrease in the prefiled BPA VERBS costs of $1.6 million, to $7.2 million.

4) Projected BPA Generation Imbalance Service costs of $0.8 million, which reflects projected costs associated with BPA deploying balancing capacity as energy when actual wind generation deviates from the hourly schedule.

The prefiled projected costs to integrate PSE's renewable wind resources in the rate year total $12.7 million, which includes (i) $9.6 million payable to BPA to integrate hourly schedules for Hopkins Ridge, LSR Phase 1 and Klondike III and (ii) $3.2 million of costs incurred by PSE to integrate Wild Horse and Wild Horse Expansion hourly, and day-ahead costs for all wind projects. These costs are presented in Table 2 below. To reflect the VERBS scheduling election made by PSE on April 5, 2013 and the subsequent $1.6 million decrease in VERBS costs, Table 3 presents to-be-filed updates to power costs.

Table 2. Prefiled Rate Year Costs to Integrate PSE Wind Resources

Wind Project & Capacity	Capacity Factor	Rate Year Generation	Balancing Authority	Total Costs	$/MWh
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Total Wind Integration Costs				$12,746,642	

Table 3. Rate Year Costs to Integrate PSE Wind Resources, Updated For PSE's VERBS 30/60 Committed Scheduling Election

Wind Project & Capacity	Capacity Factor	Rate Year Generation	Balancing Authority	Total Costs	$/MWh
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Total Wind Integration Costs				$11,173,742	
Decrease In Total Costs due to change in Scheduling Election				($1,572,900)	

B. BPA Wind Integration Costs

Q. How does BPA integrate Hopkins Ridge, LSR Phase 1, and Klondike III?

A. For Hopkins Ridge and LSR Phase 1, PSE provides BPA with wind generation schedules and receives the hourly scheduled generation from BPA. BPA manages the instantaneous wind variability and unanticipated wind ramps. For Klondike III, PSE receives the forecasted wind output from the project's owner/operator, Iberdrola Renewables. PSE then provides BPA with wind generation schedules, and receives the hourly scheduled generation from BPA.

Q. Please describe BPA's wind integration services.

A. BPA's wind integration services are VERBS and Generation Imbalance Service:

1) VERBS reflects the costs of BPA providing balancing capacity from the Federal Columbia River Power System ("FCRPS") and consists of three components:

(i) regulating reserves, which compensate for moment-to-moment differences between generation and load;

(ii) following reserves, which compensate for larger differences occurring over longer periods of time during the hour; and

(iii) imbalance reserves, which compensate for the differences between the generator's scheduled and the actual generation during an hour.

2) Generation Imbalance Service captures the after-the-fact difference between scheduled and actual energy delivered from generation resources in the BPA BAA during a schedule period. Generation Imbalance provides an energy accounting mechanism capable of recovering a market cost or benefit of delivering scheduled versus actual energy. These are captured as transmission costs and benefits in rate year power costs.

BPA's wind integration charges are designed to capture the costs of (i) reserving generating capacity capable of providing balancing services (VERBS) and (ii) deploying that capacity as energy when needed (Generation Imbalance Service).

Q. What is the BPA VERBS rate?

A. The BPA VERBS rate is currently $1.23/kW-mo, which was included in the 2011 GRC power cost forecast. As discussed above, the BP-14 Rate Case has proposed different VERBS rates effective October 1, 2013. PSE's prefiled power costs include BPA's uncommitted scheduling VERBS rate of $1.39/kW-mo; however based on PSE's subsequent VERBS scheduling election, the BPA's VERBS rate applicable to PSE will decrease to $1.14/kW-mo, as shown in Table 4 below.

Table 4. BPA 2014 Rate Case VERBS Rate Impacts to Rate Year Power Costs

	Current Rate per kW-mo	Proposed Uncommitted Rate per kW-mo	$1.39 per kW-mo Rate Year Cost Increase	Proposed 30/60 Committed Scheduling Rate per kW-mo	$1.14 per kW-mo Rate Year Cost Increase	$ Impact of VERBS Scheduling Election
Regulating Reserve	$0.08	$0.08	[redacted]	$0.08	[redacted]	[redacted]
Following Reserve	$0.37	$0.36	[redacted]	$0.36	[redacted]	[redacted]
Imbalance Reserve	$0.78	$0.95	[redacted]	$0.70	[redacted]	[redacted]
Total	$1.23	$1.39	[redacted]	$1.14	[redacted]	[redacted]

Q. How are power costs affected by BPA's proposed changes in VERBS rates?

A. As shown in Table 4 above, rate year power costs increase approximately $1.0 million due to BPA's proposed VERBS rate increase to $1.39/kW-mo for LSR Phase 1, Hopkins Ridge and Klondike III. Table 5 below provides the prefiled projected rate year wind integration costs payable to BPA for PSE's facilities residing in the BPA BAA. PSE's recent scheduling election for VERBS at the 30/60 committed scheduling rate of $1.14/kW-mo would reduce rate year power costs approximately $1.6 million.

Q. What are the rate year BPA wind integration costs included in this filing?

A. The rate year wind integration costs assumed payable to BPA for its wind integration services total $9.6 million as shown in Table 5 below.

Table 5. 2013 PCORC Prefiled BPA Wind Integration Costs

Wind Project & Capacity	VERBS	Generation Imbalance	Total
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	[redacted]
BPA Wind Integration Costs	**$8,745,324**	**$839,409**	**$9,584,733**

As negotiated in the Klondike III PPA, PSE is [redacted].

C. PSE Wind Integration

Q. How does PSE integrate wind within the PSE BAA?

A. For most of the rate year, PSE's average annual 720 MW share of Mid-C hydro generation may be sufficient to manage the instantaneous load and wind generation volatility with the BAA. As noted above, PSE operators must rebalance the system by increasing or decreasing generation from the Mid-C and/or other PSE generating assets within PSE's system if actual real-time generation output diverges from the hourly scheduled wind output. PSE generally balances second-to-second changes in wind generation with Mid-C hydro generation, which is on Automatic Generation Control ("AGC") and can respond to small fluctuations almost instantaneously. Large ramping events or large forecast errors within the hour may require dispatcher intervention beyond what AGC balancing resources can provide.

Q. Are there periods of the year during which the ability of Mid-C hydro system to provide balancing service is less flexible than during other periods of the year?

A. Yes. During the spring runoff period, when Columbia River flows are high (typically April through July), the Mid-C hydro system is less flexible than during other periods of the year. The volume of stream flow during this period is too large to be stored and shaped without incurring large amounts of spill (water passed through a spillway rather than through a generator and does not produce electricity). Spill must be limited due to the adverse health impacts to fish caused by high levels of total dissolved gas ("TDG"), a by-product of spill. During this time, Mid-C flexibility is limited between available capacity and an elevated minimum generation limit that does not violate the TDG limits.

Q. How does PSE balance output from wind in the PSE BAA during periods in which the flexibility of the Mid-C system is limited?

A. When the Mid-C system cannot provide the necessary flexibility to balance the output from wind, PSE must use its thermal resources and market transactions to balance the system. During the spring runoff periods of each of the last three calendar years (2010-2012), PSE experienced insufficient Mid-C flexibility and managed wind output using its thermal resources. PSE dispatched thermal units and operated mostly at minimum and maximum generation levels to provide flexible capacity to either increase or decrease generation.

Short-term market transactions (spot or real-time) are also an important component to provide wind integration support, and they will continue to be a critical component into the future as markets evolve in the Pacific Northwest to address regional integration and imbalance issues.

Q. How does PSE's share of the Mid-C hydroelectric projects affect PSE's ability to integrate wind resources?

A. Consistent with standard operating practices, the vast majority of PSE's regulating reserves (capacity capable of balancing moment-to-moment deviations in actual and scheduled generation) will be provided by the AGC from PSE's share of Mid-C hydro generation. Due to expiring Mid-C hydro generation contracts, PSE's current share of the Mid-C hydro capacity averages approximately 720 MW, in contrast to Mid-C capacity greater than 1,000 MW as recent as 2011. Even as PSE's contractual capacity rights to the Mid-C hydro projects have decreased over recent years, PSE has continued to satisfy its balancing obligations reliably. Due to PSE's reduced rights to Mid-C capacity, PSE experienced a greater number of instances in which such capacity was unable to provide the necessary wind integration services. In these circumstances, PSE called upon a combination of combined cycle combustion turbines ("CCCT") and simple cycle combustion turbines ("SCCT") to provide balancing reserve capacity.

Table 6 below provides total SCCT starts across PSE's eight SCCT units in 2010 through 2012, as compared to PSE contractual Mid-C capacity and installed wind capacity in the PSE and the BPA BAAs. Although some of the SCCT starts are the result of economic dispatch, many of the starts occurred as a result of needing additional balancing reserve capacity or energy.

Table 6. Historical SCCT Starts vs. Wind and Mid-C Capacity

	2010	2011	2012
Average Mid-C Capacity (MW)	[redacted]	[redacted]	[redacted]
PSE-Owned and 3rd-Party Wind Capacity (MW)[7]	[redacted]	[redacted]	[redacted]
SCCT Starts	[redacted]	[redacted]	[redacted]

The historical change in SCCT starts reflects how PSE has had to modify operations to accommodate system balancing requirements with less Mid-C capacity. PSE utilizes SCCT plants in any situation where PSE's Mid-C, economically dispatched CCCTs[8], and market transactions are unable to meet PSE's wind integration requirements.

D. PSE Wind Integration Costs

Q. Has PSE updated the costs of integrating its wind resources in the PSE BAA from those included in the 2011 GRC?

A. Yes. PSE has completed a study of the costs to integrate wind resources in the PSE BAA by studying the impact from providing balancing capacity attributable to incremental wind generation being located in the PSE BAA.

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[7] The wind MW values shown includes PSE's wind in BPA's BAA and wind in PSE's BAA (including third-party wind).

[8] If CCCT units are economically dispatched, they are considered to be available to provide balancing capacity.

Q. What are the wind integration costs PSE incurs to integrate its wind resources?

A. To ensure that PSE has sufficient ability to increase or decrease generation to balance variable wind generation, PSE must hold capacity in reserve on an hour-ahead basis. The costs associated with providing this balancing capacity are called hour-ahead wind integration costs.

PSE takes a least-cost approach to integrating wind hour-ahead, in that it first utilizes its Mid-C hydro assets to ensure adequate balancing reserve capacity is held prior to each operating hour. If constraints limit the flexibility of the Mid-C and market transactions are not available, then PSE calls upon its most efficient thermal resources to provide any remaining balancing capacity need. This hour-ahead wind integration cost applies only to Wild Horse and Wild Horse Expansion because the remainder of PSE's wind assets are balanced each hour by BPA. PSE also incurs opportunity costs in the day-ahead period for *all* of its wind resources, including wind plants located in the BPA BAA, and these are called day-ahead wind integration costs.

Table 7 lists the projected day-ahead and hour-ahead wind integration costs of utilizing PSE's system to integrate all of its wind resources.

Table 7. 2013 PCORC PSE Wind Integration Costs

Wind Project & Capacity	Day-Ahead	Hour-Ahead	Total
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	[redacted]
PSE Wind Integration Costs	$980,336	$2,181,572	$3,161,909

Q. Are PSE wind integration costs equivalent to BPA's wind integration costs?

A. No. There are differences in the types of costs captured in the BPA VERBS rate and those captured in PSE's wind integration costs. BPA allocates three types of costs related to providing balancing reserve capacity to VERBS customers:[9]

(i) a portion of the total embedded costs, such as depreciation and operations and maintenance, of the FCRPS used to provide balancing capacity;

(ii) "direct assignment" of certain costs, which consists of the annual budget for BPA's Wind Integration Team; and

(iii) a portion of the total variable costs of the FCRPS to provide and deploy balancing capacity.

Comparatively, the PSE hour-ahead wind integration costs capture only the variable costs of PSE resources used to provide balancing capacity. PSE does incur embedded costs for the resources utilized to provide PSE's wind integration services; the embedded costs, however, are already included in PSE's Power Cost

[9] BP-12-FS-BPA-05. 2012 BPA Final Rate Proposal, Generation Inputs Study

Adjustment mechanism's baseline rate, and therefore are not included in the PSE hour-ahead wind integration costs.

E. PSE Day-Ahead Wind Integration Costs

Q. Please explain what day-ahead wind integration costs represent.

A. The day-ahead wind integration costs are costs PSE incurs between the day-ahead and real-time markets due to the uncertainty of wind power generation. These costs represent the "opportunity" costs associated with setting up a power portfolio position on the day-ahead basis (employing a forecast of wind generation), only to have PSE's position change as the wind forecast is updated hour-ahead.

Q. How does PSE track actual costs to integrate its wind resources on a day-ahead basis?

A. PSE maintains a dynamic power portfolio comprised of load and generating assets. Therefore, it is difficult to isolate and track the effects of just one variable (e.g., wind forecast error). Although balancing actions may not be directly attributed to correcting the day-ahead forecast error, the magnitude and opportunity cost of the day-ahead wind production forecast error on PSE's market position is known and capable of measurement as discussed below.

Q. Please explain how PSE incurs a day-ahead opportunity cost.

A. PSE considers the day-ahead wind forecasts for Hopkins Ridge, LSR Phase 1, Wild Horse, Wild Horse Expansion, and Klondike III as firm power when planning the generation and market positions required to meet load for the following day. During the actual operating hour, loads and resource generation will deviate from their hourly schedules and forecasts, thereby requiring continuous responses from PSE resources to maintain load-resource balance.

PSE must transacts in the day-ahead market, or commit thermal units based on day-ahead market prices and heat rates, to ensure sufficient energy and balancing capacity will be available for real-time operations. When real-time market prices clear and the portfolio position is updated with the latest wind forecast, PSE's day-ahead operating practice results in *both* incremental costs and benefits due to changes in market prices and wind power forecasts from day-ahead to real-time. The net of these incremental costs and benefits is currently a cost that accounts for the pro forma net cost implications of day-ahead wind generation forecast uncertainty.

Q. Why did PSE develop projected day-ahead wind integration costs for LSR Phase 1 using characteristics of Hopkins Ridge?

A. LSR Phase 1 has been operational since February 29, 2012. With limited historical data for LSR Phase 1, PSE relied on the characteristics of Hopkins Ridge as a reasonable proxy for LSR Phase 1 because Hopkins Ridge and LSR Phase 1 are separated by less than one mile at the north edge of Hopkins Ridge. In this regard, Hopkins Ridge and LSR Phase 1 are considered to reside within the same topographic footprint resulting in similar atmospheric and terrestrial conditions that ultimately drive wind generation.

F. PSE Hour-Ahead Wind Integration Costs

Q. What are hour-ahead wind integration costs?

A. Hour-ahead wind integration costs are costs that PSE incurs to ensure resources are standing ready at the start of each operating hour to meet potential within-hour fluctuations in wind generation. Hour-ahead wind integration costs include hour-ahead wind forecast error, which, if left unaddressed, will result in load – resource imbalance. PSE incurs costs when resources that would have been dispatched—but for the presence of wind—are instead withheld from the energy market. Conversely, generation that would not have been dispatched—but for the presence of wind—may be committed into the market.

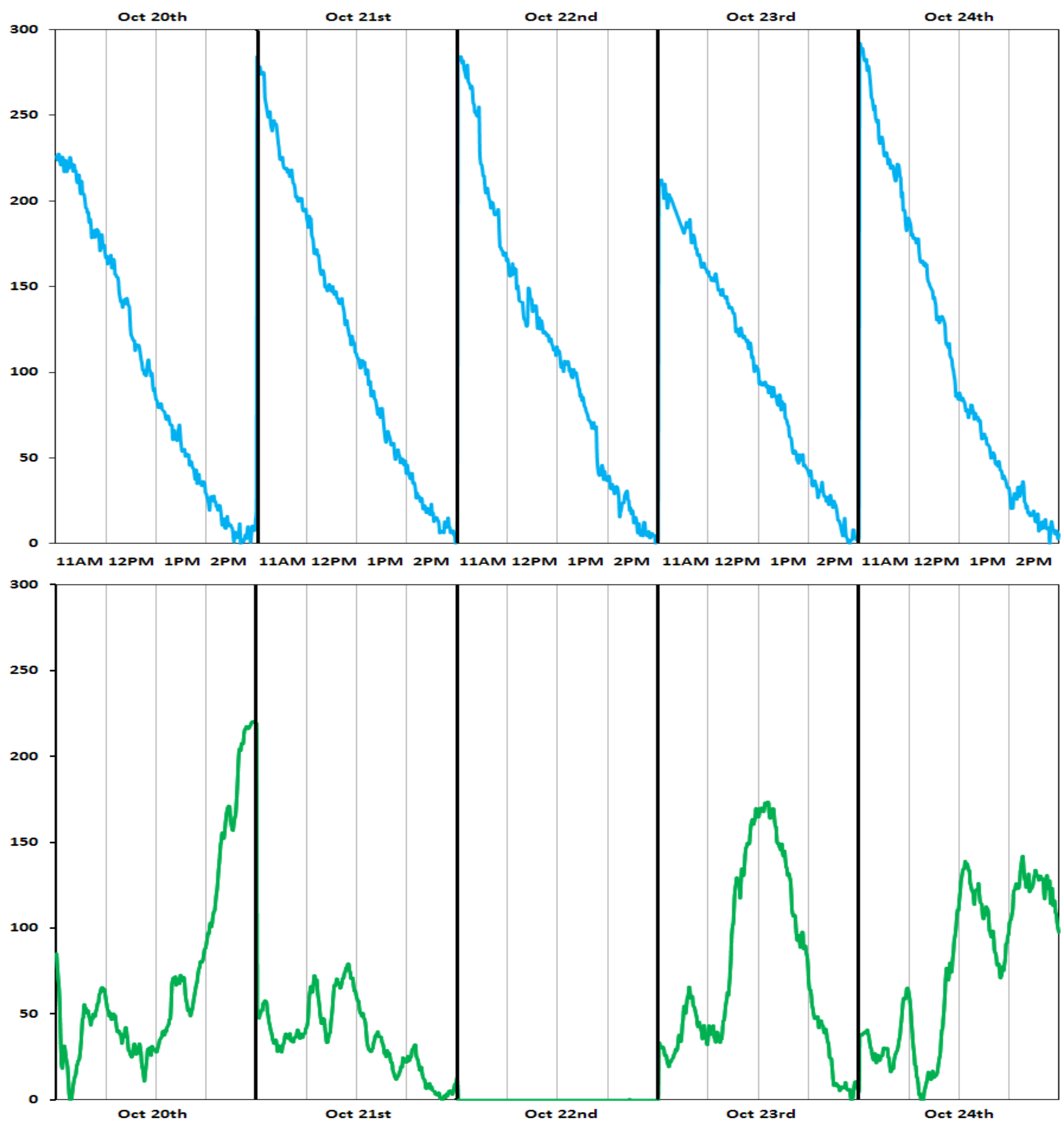
Q. Please describe the difficulties in balancing within-hour wind generation deviations.

A. For those wind facilities located in the PSE BAA, PSE must balance hourly fluctuations in wind output to maintain system reliability. Although these fluctuations may be similar to those observed with load, wind generation poses its own unique challenges.

For example, Table 8 below depicts a four-hour period from 11:00 a.m. to 3:00 p.m. for the five weekdays of October 20 through October 24, 2008. The top portion shows a snapshot of the PSE system load during each of the four-hour windows. Across these five days, the magnitude and direction of daily load movements are nearly identical. PSE has great ability to anticipate system load, especially the shape of load, and therefore can position its system resources in advance of the hour to follow changes in load within the hour with a relatively high degree of certainty.

The lower portion of Table 8 shows movements in Wild Horse generation during the same week and same four-hour windows, and showcases the variability present in wind. The variability is not consistent in terms of magnitude, duration, between hours, or across days and necessitates the need for other system resources with unloaded capacity standing ready to balance this variability.

Table 8. Load Versus Wild Horse Wind Variability



Additionally, while these traces show the variability of wind generation within and between hours that PSE must manage, it is also important to note these traces do not convey the uncertainty in the hourly wind forecast, an important difference between movements in load and wind. Balancing capacity would be necessary to address the variability in wind even if PSE knew exactly what to expect each hour.

The uncertainty presented by hourly wind forecasts, however, compounds the balancing capacity that PSE must commit to integrate wind.

Q. For which resources does PSE incur hour-ahead wind integration costs?

A. PSE incurs hour-ahead wind integration costs for all of its wind resources. Specifically, Hopkins Ridge, Klondike III, and LSR Phase 1 are within the BPA BAA; therefore, PSE will pay the BPA VERBS and Generation Imbalance rates to balance generation from these wind resources. Wild Horse and Wild Horse Expansion are within the PSE BAA; therefore, PSE bears the direct costs of integrating wind generation from Wild Horse and Wild Horse Expansion.

Q. How does PSE integrate third-party wind?

A. In addition to balancing the output from Wild Horse and Wild Horse Expansion, PSE must also manage the output from third-party wind projects located within the PSE BAA. Third-party wind projects are owned and operated by other entities and, although they are interconnected to the PSE BAA, they serve load outside the PSE BAA. As a Balancing Authority, PSE is responsible for delivering the scheduled amount of third-party wind to the sink BAA regardless of actual wind power output. Effectively, third-party wind in the PSE BAA is operationally indistinguishable from PSE-owned wind assets and is managed in a similar manner to Wild Horse and Wild Horse Expansion.

The Vantage[10] Wind Project ("Vantage"), located in Central Washington, with a nameplate capacity of 96 MW, is the only third-party wind project currently in the PSE BAA and the only third-party wind project expected in the PSE BAA during the rate year.

G. <u>Comparison of Wind Integration Costs in This Proceeding to Wind Integration Costs in the 2011 GRC</u>

Q. How have the costs to integrate PSE's wind resources changed from those currently set in rates?

A. Because of modeling changes described later in this prefiled direct testimony, projected day-ahead wind integration costs for all of PSE's owned wind facilities decreased from an average $[redacted]per megawatt hour ("/MWh") for the rate year in the 2011 GRC to an average $[redacted]/MWh for the rate year in this proceeding. Additionally, hour-ahead wind integration costs at Wild Horse and Wild Horse Expansion decreased from $[redacted]/MWh to $[redacted]/MWh. The rate reduction at Wild Horse and Wild Horse Expansion resulted from updates to PSE's wind integration modeling methodology, including how PSE allocates the diversity between load and wind volatility, and updates to the operating characteristics of PSE's gas-fired resources making them more economic as balancing resources.

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[10] The Vantage Wind Project is owned by Invenergy.

IV. MODELING WIND INTEGRATION COSTS

A. Wind Integration Models

Q. What models does PSE use to forecast wind integration costs?

A. PSE uses separate models to forecast the rate year day-ahead and hour-ahead wind integration costs. The day-ahead model is MS Excel-based and forecasts the day-ahead wind integration costs for all PSE wind resources using historical market price and wind forecast data. The hour-ahead model is SAS-based and forecasts the hour-ahead wind integration costs only for Wild Horse and Wild Horse Expansion because the remaining PSE wind facilities are balanced hourly in the BPA BAA.

Q. Why are these models necessary?

A. AURORA, the hourly dispatch model utilized by PSE in this rate case, calculates the expected value of the variable costs of operating PSE's generating resources but does not include any costs associated with wind forecast uncertainty (day-ahead or hour-ahead) or procuring balancing capacity hour-ahead. As explained above, wind integration costs represent the costs or benefits resulting from PSE managing the uncertainty in wind generation, from day-ahead forecast to hour-ahead forecast, and the volatility of wind generation within the hour. AURORA, however, treats PSE wind profiles as fixed generation for each hour of a 168 hour week which changes for each calendar month. These fixed profiles do not account for any forecast error or variability.

The AURORA model economically dispatches PSE's thermal resources based upon their individual operating characteristics (e.g., heat rate, min/max capacity) relative to the market-implied heat rates in AURORA. Therefore, the fixed hourly profiles of PSE's wind resources have no impact on the AURORA modeled thermal units' generation or costs.

Moreover, the designation of wind resources as "must run" in AURORA does not capture the day-ahead uncertainty in wind production. AURORA models wind production as fixed and firm and does not consider how changes in the wind production forecast from day-ahead to real-time affects power costs.

As the costs associated with wind variability and uncertainty are not included in the AURORA production cost model, these costs must be modeled separately, using actual data, and are included in the "Not in Models" section of rate year power costs.

B. Modeling Day-Ahead Wind Integration Costs

Q. Please explain how PSE models costs to integrate wind resources on a day-ahead basis.

A. There are two components to modeling the day-ahead wind integration cost which represent the opportunity costs of integrating PSE's wind assets day-ahead:

1) Energy Component: the day-ahead wind production forecast error, which represents the energy component; and

2) Market Price Component: the market price differential between day-ahead and hour-ahead, which represents the per-megawatt "opportunity" cost component.

For the energy component for all of PSE's owned wind facilities, PSE maintains historical records of day-ahead wind production forecasts and hour-ahead (also known as real-time) wind production forecasts provided by 3TIER (PSE wind forecast provider). The difference between the day-ahead wind generation forecast and the hour-ahead wind generation forecast depicts, on an hourly level, the wind production long or short position relative to the day-ahead forecast.

For the market price component, PSE compares the historical day-ahead peak and off-peak energy prices from the Intercontinental Exchange ("ICE") to the historical Dow Jones Mid-Columbia Index ("Mid-C Index") hour-ahead spot energy price. The hourly market price difference depicts the cost or benefit per megawatt of the forecast error.

Together, the energy and market price components represent the opportunity cost of integrating PSE's wind assets day-ahead. For example, consider two hypothetical hours. In the first hour, the day-ahead forecast for Hopkins Ridge was 85 MW and the day-ahead firm peak price was $30.00/MW. In real-time, the wind forecast updated to 90 MW and the real-time market price was $25.00/MW. The wind forecast error resulted in a 5 MW surplus, which is priced at an "opportunity" cost of $5.00/MW, representing the lost marginal revenue from being unable to sell the surplus 5 MW in the day-ahead market, resulting in a total day-ahead wind integration cost of $25.00 (5 * $5.00) for that hour.

In the subsequent hour, the day-ahead forecast for Hopkins Ridge was 90 MW, which was then updated to 70 MW in real-time. The day-ahead peak price was still $30.00/MW for the hour, with a real-time price of $24.00/MW. The day-ahead forecast error resulted in a deficit of 20 MW in real-time, which in this hour ends up being a benefit because the real-time market price is lower than the day-ahead price and results in a marginal benefit of $6.00/MW. The day-ahead wind integration cost is actually a benefit in this hour, of $120.00 (20 * $6.00).

Q. Where did PSE obtain the data for the day-ahead wind integration cost calculation?

A. PSE uses two independent data sources to arrive at its day-ahead wind integration costs. For the energy component, both the day-ahead and hour-ahead wind forecasts are provided by 3TIER. 3TIER utilizes state-of-the-art forecasting methods to provide PSE with hourly wind generation forecasts for each wind facility to seven days into the future. For the market price component PSE uses the historical day-ahead and hour-ahead prices provided by the ICE and the Mid-C Dow Jones Index, respectively.

These two datasets are time-synchronized to ensure the realized day-ahead forecast error for each hour corresponds to the realized market price change for that hour. For this proceeding PSE has relied on historical data covering the six-year period from 2007 through 2012.

Q. What model does PSE utilize to forecast day-ahead wind integration costs?

A. PSE uses an MS Excel-based tool to model day-ahead wind integration costs. The tool utilizes historical power price and wind forecast data to compute a day-ahead wind integration cost for each hour. These costs can be aggregated to various levels, such as by month or annually, for further analysis. For the rate year, PSE forecasts day-ahead wind integration costs based on the annual average day-ahead cost observed over the past six years.

Q. Please explain the decrease in day-ahead wind integration costs from the 2011 GRC.

A. Since the 2011 GRC, there have been two updates to the modeling of the day-ahead wind integration costs: 1) the methodology to determine the market price component; and 2) the hour ahead wind forecast data which is part of the energy component. Both updates were made to improve the alignment of expected day-ahead wind integration costs for the rate year with historical day-ahead wind costs.

C. Hour-Ahead Wind Integration Costs

Q. Please explain how PSE models costs to integrate wind resources on an hour-ahead basis.

A. There are two steps in the process of modeling PSE's hour-ahead wind integration costs.

1) PSE analyzes AURORA hourly resource dispatch to assess whether there is insufficient balancing capacity available on PSE resources to meet the hourly balancing capacity requirement.

2) PSE adjusts the AURORA resource dispatch to meet the balancing capacity requirement in hours with insufficient balancing capacity.

Use of 70 simulations of hourly AURORA dispatch allows hour-ahead wind integration costs to be tied to the rate year forecasts for resource dispatch, power and gas prices, and hydro conditions. When presented with insufficient balancing reserve capacity hour-ahead, the hour-ahead wind integration model modifies the AURORA dispatch in a least-cost manner using PSE's Mid-C hydro resource first, and then gas-fired resources only when necessary, taking into consideration thermal units heat rates and operational availability.

After resources are re-dispatched, the hour-ahead wind integration cost is determined by summing all hourly changes to production costs (positive and negative) for the entire rate year. Incorporating all 70 AURORA simulations allows PSE to create a distribution of Wild Horse and Wild Horse Expansion hour-ahead wind integration costs for the rate year, which in turn allows PSE to be more certain in the expected cost of $[redacted].

Each step in the model is consistent with the unique operating characteristics of PSE resources and the AURORA simulation of prices and economic dispatch of PSE resources for the rate year. For additional details on the model methodology, please see the Second Exhibit to the Prefiled Direct Testimony of Mr. Matthew D. Rarity, Exhibit No. ___(MDR-3).

Q. Have there been any changes to PSE's hour-ahead wind integration model?

A. Yes. There have been several changes to PSE modeling efforts since the 2011 GRC. At a descriptive level, the Ancillary Valuation Model utilized in the 2011 GRC has been renamed the Hour-Ahead Balancing Model ("HABM") to improve the clarity of the model's purpose. Additionally, there have been numerous updates to the HABM aimed at refining the nature of system operations and constraints. Changes include incorporating reserve capacity for PSE's contingency reserve obligation into the base set of assumptions, allocating balancing capacity between load and wind, accounting for diversity between wind facilities, as well as explicitly modeling two sub-categories of INC balancing capacity: spinning and non-spinning reserves. For additional details on the HABM, please see the Second Exhibit to the Prefiled Direct Testimony of Mr. Matthew D. Rarity, Exhibit No. ___(MDR-3).

Q. Did PSE include Vantage in the HABM analysis?

A. Yes. As part of PSE's BAA obligations, PSE must balance the wind generation from interconnected third-party wind facilities, which currently is limited to Vantage. As with Wild Horse and Wild Horse Expansion, this requires PSE to set aside balancing capacity hour-ahead to balance output from both projects. Therefore, PSE has included Vantage in the analysis determining the amount of balancing capacity to set aside each hour. The rate-year hour-ahead wind integration costs presented in this proceeding, however, reflect only the portion of the hour-ahead wind integration costs associated with Wild Horse and Wild Horse Expansion.

The inclusion of Vantage in determining the balancing capacity requirement captures the diversity between multiple wind facilities, and reduces the amounts of balancing capacity to be held each hour. Diversity in wind generation results when the volatility in generation between wind projects are not perfectly correlated; each wind project will exhibit its own standalone volatility, but they do not necessarily vary at the same time or in the same direction. The result is that the total amount of balancing capacity required for all wind facilities, when measured together, will be smaller than the sum of individually determined amounts. This type of diversity can also be found between wind projects and system load, and has likewise been captured in PSE's balancing capacity requirements.

To be clear, PSE includes Vantage as an intermediate step in determining the total balancing capacity requirement for the PSE BAA and results in a lower wind balancing capacity requirement for Wild Horse and Wild Horse Expansion than if Wild Horse and Wild Horse Expansion were measured in isolation. The costs for providing wind integration for third-party wind are not included in the $2.2 million rate year hour-ahead wind integration costs.

Q. How does PSE ensure the quality of the data?

A. PSE analyzes the historical data serving as inputs to PSE's wind integration cost models to ensure they do not contain erroneous data. Inaccurate data can arise from telemetry errors from the devices recording generation values, such as negative generation values or values above the capacity of a facility. Data corruption can occur when the database recording the observations freezes or experiences software errors. For small periods of erroneous data, the observations are replaced using linear extrapolation. For extended periods of missing or bad data, the observations are withheld from the analysis.

Q. How has PSE stayed abreast of and applied, where cost effective, more rigorous means to determine wind integration costs?

A. PSE has continued to improve its modeling and knowledge of wind integration costs across several fronts. For modeling, PSE has updated the HABM to reflect specific system balancing operations, such as distinction of spinning and non-spinning reserves, accounting for wind diversity, and updated operational constraints on PSE resources. PSE has contacted AURORA’s developer, EPIS, to understand AURORA’s capabilities for modeling balancing reserve capacity. Regionally, PSE has been active in several groups aimed at addressing wind integration issues in the Northwest and Western Electric Coordinating Council. This participation has allowed PSE to collaborate with other regional entities, such as Pacific Northwest National Laboratory and the National Renewable Energy Laboratory, sharing experiences with wind integration and techniques for modeling system operations.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.