EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-09___/UG-09___
2009 PSE GENERAL RATE CASE
WITNESS: DAVID E. MILLS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-09____** **Docket No. UG-09____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS
ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

MAY 8, 2009

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

I. INTRODUCTION

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

A. My name is David E. Mills. My business address is 10885 NE Fourth Street, Bellevue, WA 98004. I am the Director, Energy Supply & Planning for Puget Sound Energy, Inc. ("PSE" or "the Company").

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

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

Q. Please explain your duties as Director, Energy Supply & Planning for PSE.

A. My responsibilities include oversight of the Company's Power Supply Operations and Gas Supply Operations Departments, including the following: (i) managing all PSE short-term (intra-month) and medium-term (up to three years) wholesale power and natural gas portfolios; and (ii) working with the Company's Energy Resources Department to plan for long-term hedging requirements. My responsibilities also include developing strategies to address risks related to PSE's electric and gas portfolios and developing the Company's Integrated Resource Plan.

Q. What is the nature of your testimony in this proceeding?

A. My testimony addresses the following issues:

(i) the Company's power and gas portfolio[1] risks,

(ii) the Company's structures and policies to manage these risks, including but not limited to hedging strategies,

(iii) the Company's activities with respect to wind integration,

(iv) the Company's efforts to acquire additional transmission,

(v) the Company's reassessment of its electric resource need,

(vi) economic dispatch of power generation resources, such as the Company's Mint Farm Energy Center and Sumas natural gas-fired combined cycle generating facilities,

(vii) the Company's pending agreements to sell excess Renewable Energy Credits and Renewable Portfolio Standard energy,

(viii) the Company's projected rate year power costs for this proceeding, and

(ix) the Company's comparison of projected rate year power costs for this proceeding to the projected rate year power costs approved in the Company's last general rate case in WUTC Docket Nos. UE-072300 and UG-072301 (consolidated).

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[1] These "portfolios" consist of resources available to PSE to serve its customers. The electric portfolio includes generation facilities, purchased power and transmission capacity. The gas portfolio includes gas supply, storage and pipeline transportation capacity. Please see the prefiled direct testimony of Ms. Kimberly J. Harris, Exhibit No. ___(KJH-1CT), for a discussion of the power and gas portfolios.

II. VOLATILITY AND RISK IN PSE'S ELECTRIC AND NATURAL GAS RESOURCE PORTFOLIOS

Q. Why is energy risk management a concern to the Company?

A. PSE's resource portfolio is subject to significant volatility and risk that ultimately have a substantial impact on energy costs, which is one of the reasons the Company has dedicated portions of two departments to energy risk management matters.

Q. What are the volatility and risk drivers in the natural gas portfolio?

A. The Company's natural gas supply portfolio is composed of a mix of supply contracts from various producing areas, including the Western Canadian Sedimentary Basin, the Rocky Mountain area, and the San Juan Basin.

The major causes of gas cost volatility for the Company are (i) demand variations due to changes in weather, (ii) gas transportation constraints and (iii) wholesale natural gas market prices. The Company's retail natural gas demand is closely correlated to temperature (*e.g.*, demand increases as temperatures decrease). The Company addresses this gas cost volatility through gas storage and transactions in the wholesale gas markets. Because the Company purchases and sells in the wholesale gas markets to address this volatility, the Company faces risks associated with the volatility of market prices for gas at the various supply points.

Q. What drives volatility and risk in the power portfolio?

A. PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. Although there are many complex variables embedded in the portfolio, the major drivers of power cost volatility are: (1) streamflow variation affecting the supply of hydroelectric generation; (2) weather uncertainty affecting power usage; (3) variations in market conditions such as wholesale gas and electric prices; (4) risk of forced outages; (5) variability of wind generation; and (6) transmission constraints. All of these have an impact on load and resource volatility, which PSE may balance with wholesale market purchases and sales.

Q. Please describe the volatility related to variations in streamflow affecting hydroelectric supply.

A. During an average streamflow year, approximately twenty-five percent of PSE's electric energy production comes from hydroelectric resources. During poor streamflow conditions, which would result in less than average hydro production, PSE may need to acquire supplemental power to serve its customer load. During favorable streamflow conditions, PSE may need to sell surplus power to balance its supply portfolio. These balancing transactions are conducted in the wholesale power markets and can greatly affect PSE's power costs. The regional market price of power is heavily influenced by hydro conditions and market power prices understandably tend to be higher during a "dry" year and lower during a "wet" year.

Q. Please describe the volatility that is related to load and temperature uncertainty.

A. The Pacific Northwest is a winter peaking region in that the winter peak demand is higher than the summer peak. The level of PSE's electric retail load is correlated with temperature – meaning that during the winter heating season PSE's load increases as temperatures decline. In light of the significant electric heating load in PSE's service territory, PSE's cost related to load/temperature uncertainty can be significant. While still a winter peaking region, the Pacific Northwest also experiences summer peaking demand. This is due in part to increased use of electric air conditioning and presents another example of electric load volatility attributable to temperature.

Q. Please describe the risks related to market price volatility.

A. The foregoing volume-related risks affect PSE's exposure to market prices because as the quantity of generation resources and load demand change, PSE may be subject to significant price-related risk associated with the expected volume of its purchases and sales of power in the wholesale markets and its need to purchase or dispose of natural gas in connection with the operation of its gas-fueled generating units.

Q. Please describe the volatility related to forced outages.

A. As shown in the table below, PSE relies on 2,663 megawatts ("MW") (nameplate) of thermal generating units to help meet its customer loads. These units include 657 MW of large baseload coal generators with low variable fuel costs; 1,400 MW of gas combined-cycle combustion turbine co-generators with moderate heat rate conversions; and 606 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generators.

Thermal Generation Units	
	Capacity (MW)
Coal	657
Goldendale	277
Mint Farm	296
Frederickson 1/Epcor	134
Encogen	170
Sumas	133
NUGs	390
Simple Cycle CTs	606
Total Megawatts	2,663

Material or equipment failure, fire, electrical disturbances, or other such events typically cause forced outages. Forced outages at any of these units can expose PSE to significant price volatility in its power supply portfolio.

Q. Please explain the variability of wind generation.

A. PSE's power portfolio benefits from approximately 480 MW of wind generation capacity. Wind resources, however, have great variability surrounding the short-term wind generation forecasts compared to actual generation. PSE must manage this short-term generation variability by reshaping its contracted Mid-Columbia ("Mid-C") hydro generation and utilizing other generating assets within its system to accommodate the wind projects' power variations. Such reshaping affects PSE's power costs as PSE's other resources' generation levels are adjusted on a real-time basis to accommodate fluctuations in wind generation. Wind integration costs are discussed in more detail later in my testimony.

Q. What risks are related to transmission and transportation constraints?

A. The Company is exposed to transmission and transportation risks such as pipeline outages, the curtailment of transmission rights due to de-ratings,[2] and forced outages. For example, if power cannot be wheeled[3] from the Mid-C trading hub, the Company would be forced to dispatch resources that may be less economic in order to meet load.

Q. Are PSE's power and gas costs subject to other risks?

A. Yes, examples of other risks include:

- counterparty credit risk, which is the risk of default by PSE's counterparties on contractual obligations; and
- execution risk, which refers to the ability to execute wholesale market transactions. Market liquidity, counterparty credit requirements, the Company's credit standing and contractual requirements are examples of execution risk.

III. PSE'S MANAGEMENT OF POWER AND GAS COST RISKS

Q. How does the Company manage the volatility of power and gas costs?

A. The Company has in place organizational structures, policies and overarching strategies to provide oversight and control of energy portfolio management

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[2] De-rating refers to a decrease in the rated electric capability of an electric transmission line.

[3] Wheeling means using the transmission facilities of one power system to transmit power of and for another system. This term is often used colloquially to mean transmission.

activities, many of which must be undertaken on an hourly and daily basis by the experienced energy traders employed by PSE. The Company also uses modeling tools that assist in projecting whether its power and gas portfolios will be surplus or deficit in future months. The Company uses these tools to develop and implement hedging strategies to reduce the cost risks associated with portfolio volatility.

Q. Please summarize the Company's efforts with respect to developing and implementing hedging strategies for its electric portfolio.

A. In order to manage its electric portfolio within a dynamic and complex environment, as described above, the Company has in place the following measures:

- internal organizations and staff dedicated to managing portfolio risks,
- executive and Board of Directors-level oversight of staff's portfolio management activities,
- specific procedures and policies governing energy portfolio management activities,
- production cost modeling techniques that develop a two hundred fifty scenario probabilistic view of PSE's wholesale electric portfolio and its underlying risks,
- use of programmatic hedging strategies that specify a range of monthly volumes to be hedged, depending upon market fundamentals,
- selection of specific commodities to be hedged as informed by Margin at Risk analyses,
- revision of strategies to incorporate up-to-date fundamental views of energy commodity markets,

- a $350 million unsecured revolving credit agreement to support the Company's energy hedging activities, and
- a counterparty credit risk system.

Q. Has the Company revised its hedging strategies since its 2007 general rate case, Docket Nos. UE-072300 & UG-072301 (consolidated) ("2007 GRC")?

A. No. Please see the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DEM-3C), for an overview of PSE's current hedging strategies. Please also see the Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DEM-4C), for an Energy Cost Risk Management presentation made to Commission Staff regarding the Company's hedging strategies.

IV. WIND INTEGRATION

Q. Please describe the Company's wind resources.

A. The Company's rate year power portfolio benefits from nearly 480 MW of wind capacity. The Company currently owns two wind projects, the Hopkins Ridge Wind Project ("Hopkins Ridge") located in eastern Washington with a capacity of 156.6 MW and the Wild Horse Wind Project ("Wild Horse") located in central Washington with a current capacity of 228.6 MW. Including the planned addition of 22 turbines discussed in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), the Wild Horse facility will have a capacity of 272.6 MW in the rate year. In addition, the Company has executed a 50 MW purchased power agreement ("PPA") with Klondike Wind Power III, LLC, an affiliate of

Iberdrola Renewables, Inc., formerly known as PPM Energy, for a portion of the output of the Klondike III Wind Project ("Klondike III"). At the time the Klondike III agreement was signed, PPM Energy was a subsidiary of ScottishPower, which Iberdrola purchased in 2007. The name change to "Iberdrola Renewables, Inc." took effect in April 2008.

Q. What are wind integration costs?

A. Wind integration costs represent the costs associated with losing the benefit of being able to operate without having to reserve capacity to balance wind generation on the day ahead, hour ahead and within-hour time frame. In essence, generation capacity that may have been dispatched but for the presence of wind is withheld from the energy market. Conversely, but for the presence of wind, generation that would not have been dispatched may be committed into the market. The cost of integrating wind into the Company's portfolio – day-ahead, hour-ahead and within-hour cost - is discussed further below and is included in the rate year power cost forecast and includes both costs paid to Bonneville Power Administration ("BPA") and internal wind integration costs.

Q. How does the Company integrate its wind generating assets?

A. Hopkins Ridge and Klondike III are both currently located in BPA's Balancing Authority Area. As a result, BPA provides integration services to manage the variable output of these wind projects. Under this service, BPA delivers the hourly scheduled amount of wind generation to the Company's system. The Company is planning to move Hopkins Ridge into the Company's Balancing Authority Area, but the timing of any such move is uncertain, so this has not been reflected in the rate year power costs. Wild Horse is located in central Washington and is interconnected to the Company's Balancing Authority; therefore, the Company's system has to accommodate the variations in wind output.

Q. Does the integration of renewable assets such as wind present any unique challenges to the Company?

A. Yes. Wind generation is an intermittent and non-dispatchable generation resource. While the variability can be managed similarly to managing the Company's load, the unpredictable nature of wind creates uncertainty. There can be large differences between the short-term wind generation forecast for the hour- and day-ahead time frames compared to actual generation. Short-term, unanticipated ramping events present some of the greatest challenges that the Company has to effectively manage its electric system to meet industry reliability standards. If actual real-time generation output diverges from the hourly scheduled wind output, the operator must rebalance the system by increasing or decreasing generation from the Mid-C and/or other generating assets within PSE's system. The instantaneous fluctuations are generally mitigated by Mid-C hydro generation which is on automatic generation control and can respond instantaneously. Automatic generation control provides regulation which in real-time corrects for moment-to-moment fluctuations in wind output. Corrections are made on a four-second cycle. Large, unanticipated ramping events must be managed within the hour using a combination of automatic generation control and dispatcher actions. Wind generation following corrects for differences over longer time increments of 10 to 50 minutes between hourly scheduling adjustments.

Q. What is the Company's experience and costs of providing integration services for its wind plants?

<u>BPA Balancing Authority</u>

A. As stated above, Hopkins Ridge is interconnected to BPA's Balancing Authority and integrated into BPA's system. Wind generation is scheduled 30 minutes prior to the start of the hour and the schedule is automatically sent to BPA. BPA then provides wind integration services to manage the variable output of wind by delivering the hourly scheduled amount of power to the Company's system.

Klondike III is also interconnected to BPA's Balancing Authority and receives the same wind integration services as Hopkins Ridge. PSE receives the forecasted wind output for both the day-ahead and hour-ahead time horizon from the project's owner/operator, Iberdrola. The forecasted wind output is then scheduled with BPA and the Company receives the hourly scheduled wind output for the next-hour. However, the instantaneous wind variability and unanticipated wind ramps are managed by BPA's Balancing Authority. As negotiated in the PPA, [redacted]

BPA's integration services are two fold: (1) generation imbalance (hour-ahead) and (2) within-hour wind integration. The generation imbalance captures the after-the-fact difference between the hourly average generation produced and the hourly scheduled generation. The within-hour wind integration service manages the "regulation," which is the second to second, minute to minute variability in wind generation and wind "generation following" that corrects for differences over longer time increments of 10 to 50 minutes.

As a result of the settlement agreement in BPA's 2009 Wind Integration Rate Case, on October 1, 2008, BPA implemented a new wind integration rate of $0.68 per kiloWatt ("kW") per month to recover costs associated with within-hour wind integration services. This translates to a fixed cost for Hopkins Ridge of $106,488 per month, $1.3 million per year or $2.68 per MWh for the rate year. As discussed below, equivalent costs for the Klondike III PPA are contractually [redacted] of the BPA rate, or [redacted] per month, [redacted] per year or [redacted] per MWh for the rate year. The actual per megawatt-hour cost will increase with less monthly wind generation produced and vice versa.

Customer workshops leading up to BPA's 2010 Power and Transmission rate cases ("BPA 2010 Rate Cases") to set new transmission rates effective October 1, 2009 indicated that BPA's wind integration rate would increase four-fold, to approximately $2.73 per kW per month for wind resources located in BPA's Balancing Authority. This translates to an estimated cost increase of $[redacted] million, or $3.9 and $[redacted] million per year for Hopkins Ridge and Klondike III PPA, respectively. The within-hour BPA wind integration cost included in the rate year power cost forecast is $[redacted] million, which translates to $10.77 per MWh and $[redacted] per MWh for Hopkins Ridge and Klondike III, respectively. Further, this anticipated increase does not include charges for Generation Imbalance, Unauthorized Increase Charge or Failure to Comply penalties that BPA may also assess and which are discussed later in my testimony under "Transmission Issues."

This anticipated wind integration rate of $2.73 per kW per month is based on a wind scheduling accuracy assumptions of a two-hour persistence forecast. A two-hour persistence forecast assumes that the hourly average metered wind generation observed two hours ago is the forecast or schedule for the next hour. If BPA assumes a higher wind scheduling accuracy (lower forecast error) such as a 60-minute or a 30-minute persistence forecast, then BPA's proposed rate could be lowered to $2.13 or $1.37 per kW per month, respectively.[4] At this time, BPA has indicated that, rather than using a two-hour persistence forecast, it will use a shorter period persistence forecast, in my view, most likely 60 minutes.

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[4] Per BPA's 2010 BPA Rate Case "TR-10 Transmission & Ancillary Services" customer workshop document dated February 4, 2009.

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Although they are interconnected to BPA's Balancing Authority and PSE pays BPA for providing wind integration services, PSE must still ensure there is adequate generation available to meet the next day's and next hour's load and thus, has to set aside sufficient reserves to mitigate the forecast error between the hour ahead and day ahead time horizons for both Hopkins Ridge and the Klondike III PPA.

PSE Balancing Authority

The Wild Horse wind farm is located in the Company's Balancing Authority. For most of the calendar year, PSE's over 1,000 MW share of Mid-C hydro generation is sufficient to manage the instantaneous Wild Horse wind and load variability and deviations from its schedule. However, during the high flow spring runoff period when the Columbia River flows are high, the Mid-C hydro system is less flexible because it has to be managed to stay within the legal Total Dissolved Gas ("TDG") limits by minimizing spill. Mid-C flexibility is limited between available capacity and the minimum generation limit that does not violate the TDG limits. To stay below the TDG limits, spill must be avoided completely or minimized by operating close to turbine capacity. This type of operation results in limited upward and downward generation flexibility. If the wind output is less than scheduled, then the system has to respond by increasing its generation; but because the Mid-C is already operating at capacity, it cannot respond. During off-peak hours, the Mid-C hydro generation and most of the other resources in PSE's portfolio are operating at or close to their minimum project generation. As a result, the system has limited downward flexibility to respond if the wind output is greater than scheduled.

When the Mid-C system does not provide the necessary flexibility to manage the Wild Horse wind project, the Company uses its thermal resources and market transactions to balance the system. During spring 2008, PSE experienced insufficient Mid-C flexibility and had to mitigate some of the wind output using its thermal resources. The thermal units were dispatched and operated at minimum, mid-point and maximum to provide the flexibility to either increase or decrease generation.

Short term market transactions (spot or real time) are an important component of wind integration within the Company's current portfolio and they will continue to be a critical component into the future as the wind portfolio expands. These shorter term transactions smooth the forecast error between the day-ahead and hour-ahead forecast time horizons. Day-ahead markets allow PSE to balance positions given the forecast error which occurs between long-term models and day-ahead wind forecasts. Real-time markets allow PSE to rebalance hourly positions for the forecast error that occurs between day-ahead scheduling and hour-ahead forecasts.

The cost associated with integrating wind in the Company's Balancing Authority can be divided into two categories: 1) within-hour balancing reserves (regulation and generation following) and 2) the cost of reshaping the Mid-C hydro generation and dispatching the thermal units for both the hour- and day-ahead time horizons.

The total wind integration cost included in the rate year for Wild Horse is approximately $[redacted] per MWh and includes both the within-hour and hour-ahead balancing reserves and the day-ahead cost.

V. TRANSMISSION ISSUES

Q. What actions has the Company taken to acquire additional transmission?

A. Among other initiatives, the Company recently participated in BPA's Network Open Season ("NOS"). The NOS is BPA's process to determine future regional transmission needs by aligning resource development plans with projected load forecasts. Commencing in 2008, and in accordance with FERC approval, BPA initiated a NOS process under its Open Access Transmission Tariff. The NOS is a multi-step process in which transmission customers submit transmission service requests for desired transmission. BPA then responds with an offer of a corresponding Precedent Transmission Service Agreement.

Q. What new transmission has PSE obtained through BPA's NOS that will affect this rate year?

A. BPA notified PSE in November 2008 that it would offer PSE all the transmission capacity PSE had requested that impact the rate year. PSE had requested transmission of 150 MW for Cross Cascades and 27 MW for the Goldendale Generating Station ("Goldendale"). Service for the Cross Cascades transmission

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commenced October 2008 (115 MW) and March 2009 (35 MW), and the Goldendale transmission rights began March 2009.

Q. Why did PSE acquire additional Cross Cascades transmission under BPA's NOS?

A. PSE's long term acquisition strategy includes resource acquisitions, market purchases, purchased power agreements, and additional wind generation. Many of these resource options are located near the Mid-C trading hub. The Cross Cascades transmission provides additional transmission capacity from the Mid-C hub back to PSE's system, which increases PSE's flexibility, increases winter peak load service reliability and reduces the risk of future limited transmission on the Cross Cascades path to meet load growth.

Q. Why did PSE acquire additional Goldendale transmission under BPA's NOS?

A. The purchase of the 277 MW Goldendale Energy Center included only 250 MW of Long Term Firm transmission capacity. The remaining 27 MW was requested through BPA's NOS to cover Goldendale duct firing capacity.

Q. What is the potential for increased BPA transmission charges associated with BPA's current NOS?

A. Actual transmission rate impacts resulting from NOS will not be fully known until BPA completes its studies and resets its transmission rate schedules. At this time, it is not known when BPA will complete these studies nor when BPA's transmission rate schedules will be adjusted. The rate year transmission costs in this proceeding include no rate increase due to the BPA's NOS.

Q. Please describe BPA's process to adjust transmission rates under its NOS.

A. BPA has decided to move forward under the NOS with the following five projects: McNary-John Day, Big Eddy-Station Z, I-5 Corridor Reinforcement, Little Goose, and West of Garrison Remedial Action Scheme. BPA has decided that some of the facilities necessary to meet several of the NOS requests do not meet the criteria to move forward at embedded cost rates: Harney Area Reinforcement, Northern Intertie Reinforcement, and LaGrande Area Reinforcement.

To estimate the embedded cost rate impacts, BPA performed a net present value analysis of the costs of the eight projects, after deducting the value of reliability benefits to the Integrated Network, and adding the revenues received from the NOS Transmission Service Requests for projects that would receive transmission service. For the net present value analysis, BPA assumed no increase in embedded cost rates to recover additional project costs, but assumed an average annual 1% embedded cost rate increase representing normal rate increases over time.

The combination of the five selected projects and the NOS Transmission Service Requests service that can be offered with such projects would result in an estimated embedded annual cost rate increase over 20 years of 2.02%, which is within the range that BPA has determined is reasonable. Adding the three projects noted above that were not selected would result in a projected embedded cost rate increase over 20 years of 12.11%, which is well above what BPA has determined is an acceptable impact on this rate.[5]

Q. What were PSE's actual costs associated with acquiring transmission through the NOS?

A. As part of the NOS process, PSE was required to submit security deposits for all Transmission Service Requests. BPA requires that point to point transmission security deposits equal the requested point to point reserved capacity, using the Long Term Firm Open Access Transmission Tariff rate, excluding Ancillary Services, applied to one year of requested service.[6] These security deposits are to be released no later than 180 days after the requested transmission service commences.

PSE has submitted security deposits into escrow under BPA's NOS totaling $12,211,584. Of these deposits, $2,756,952 relates to transmission which will increase the rate year costs: $2,336,400 for the requested Cross Cascades 150 MW and $420,552 for the requested Goldendale 27 MW. BPA awarded the Cross Cascades 150 MW in two steps (115 MW in October 2008 and 35 MW in March 2009). Late March 2009, PSE received a security deposit release of $1,791,240,

[5] Per BPA's "2008 Network Open Season Recommendation, Recommendation for Consideration and Comment" posted for discussion at January 15, 2009 Network Open Season Customer Meeting.

[6] It should be noted that security deposits, either tendered to BPA or placed in escrow, are subject to accumulation of interest in accordance with either BPA's Open Access Transmission Tariff provisions (which was set to zero for the purpose of the security deposits) or with escrow account conditions.

plus applicable interest, for the first Cross Cascades 115 MW. PSE expects to receive the remaining security deposit releases totaling $965,712, plus interest, for the remaining Cross Cascades 35 MW and Goldendale 27 MW by August 2009. Interest earned during the test year has been credited against the transmission costs for the rate year. Transmission costs included in the rate year for the Cross Cascades 150 MW and the Goldendale 27 MW are $2.7 million and $0.5 million, respectively.

Q. Is BPA planning on changing transmission rates during the rate period in this proceeding?

A. Yes. BPA is currently engaged in a 2010 transmission rate case proceeding, and new rates are expected to be implemented October 1, 2009. Prior to November 2008, BPA had been proposing an overall 4% increase in transmission rates for transmission services provided by BPA to BPA customers. BPA has since offered customers a partial settlement that excludes proposed rates for wind integration and ancillary services requiring generation inputs -- both of these issues are to be decided in BPA's 2010 power rate case. The partial settlement offer includes a zero percent transmission rate increase and significantly higher penalties for Failure to Comply and Unauthorized Increase Charges. The provisions of the partial settlement agreement concerning an increase in Failure to Comply Penalty charges are directly linked to a reduction in wind integration services proposed by BPA outside of the rate case proceedings. BPA is also proposing to increase the

Operating Reserve rates for Spinning Reserve Service from $7.93 per MWh to $11.15 per MWh and Supplemental Reserve Service from $7.93 per MWh to $9.85 per MWh. PSE has included increases for Operating and Spinning Reserves services in the pro forma transmission costs included in the rate year power cost forecast.

As mentioned in my testimony above relating to the Company's experience and costs of providing integration services for its wind facilities and outside of the partial settlement, it is expected that BPA's Generation Imbalance service will change. As part of its pro forma Open Access Transmission Tariff filing on October 3, 2008, BPA did not include Schedule 9 and Section 3 that includes Generation Imbalance service because BPA is working to reconcile wind integration costs and amounts of reserves required to accommodate wind resources within its Balancing Authority. However, BPA has addressed a component of Generation Imbalance as part of its 2010 Rate Cases by proposing to significantly increase its Intentional Deviation charge from 125% to 150% of the highest incremental cost that occurs during the day of the Intentional Deviation event.[7] Once BPA reconciles wind integration costs and reserves for the Rate Case period, it may be that BPA could increase its Generation Imbalance charges. Rate year forecast generation imbalance (hour-ahead) costs for Hopkins Ridge assume no change in BPA's Generation Imbalance service charges and average $0.79 per MWh, based upon rate year

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[7] BPA is proposing to rename this charge a "Persistent Deviation" charge.

AURORA forecast market prices. The generation imbalance costs for Klondike III are $[redacted] per MWh [redacted].

VI. ELECTRIC RESOURCE NEED

Q. Has the Company reassessed its electric resource need for the 2009 Integrated Resource Plan ("IRP")?

A. Yes. The Company updated its peak capacity planning standard in November 2008. The updated capacity standard is based on a loss of load probability analysis. It targets the amount of capacity needed for the Company to achieve a 5% loss of load probability. This 5% loss of load probability translates to a "planning reserve" margin of having sufficient capacity to meet peak load under normal (50% probability of occurring) peak conditions plus 15%. This is a standard industry approach, consistent with that of other utilities in the region and the Northwest Power Planning and Conservation Council.

Q. How does the updated planning standard compare to the former planning standard?

A. The former standard, as reflected in the 2007 IRP, was based on meeting extreme peak load at 13 degree Fahrenheit. Under this former standard, the Company planned to meet load at the 95th percentile of cold temperatures during the peak hour. The former standard did not, however, take into consideration the potential for generation units to experience a forced outage or for less than normal hydro conditions. In contrast, the loss of load probability standard takes into consideration load, hydro conditions, forced outage rates, and the duration of forced outages. It is, therefore, a more robust analytical approach to estimating that 95th percentile of reliability.

Q. Did updating the capacity planning standard affect the capacity of resources PSE needs to acquire?

A. Yes. Bringing PSE's level of reliability up to the 5% loss of load probability target increases capacity needs by approximately 300 MW in the early years and 500 MW in the later years of the 20-year planning horizon. The impact of the new planning standard is shown in my Fourth Exhibit to my prefiled direct testimony, Exhibit No. ___(DEM-5).

Q. Has this updated planning standard been discussed with external stakeholders?

A. Yes. An overview of the methodology and results were presented at an IRP Advisory Group meeting on June 19, 2008. The full write-up will appear in the 2009 IRP, scheduled to be filed by July 30, 2009.

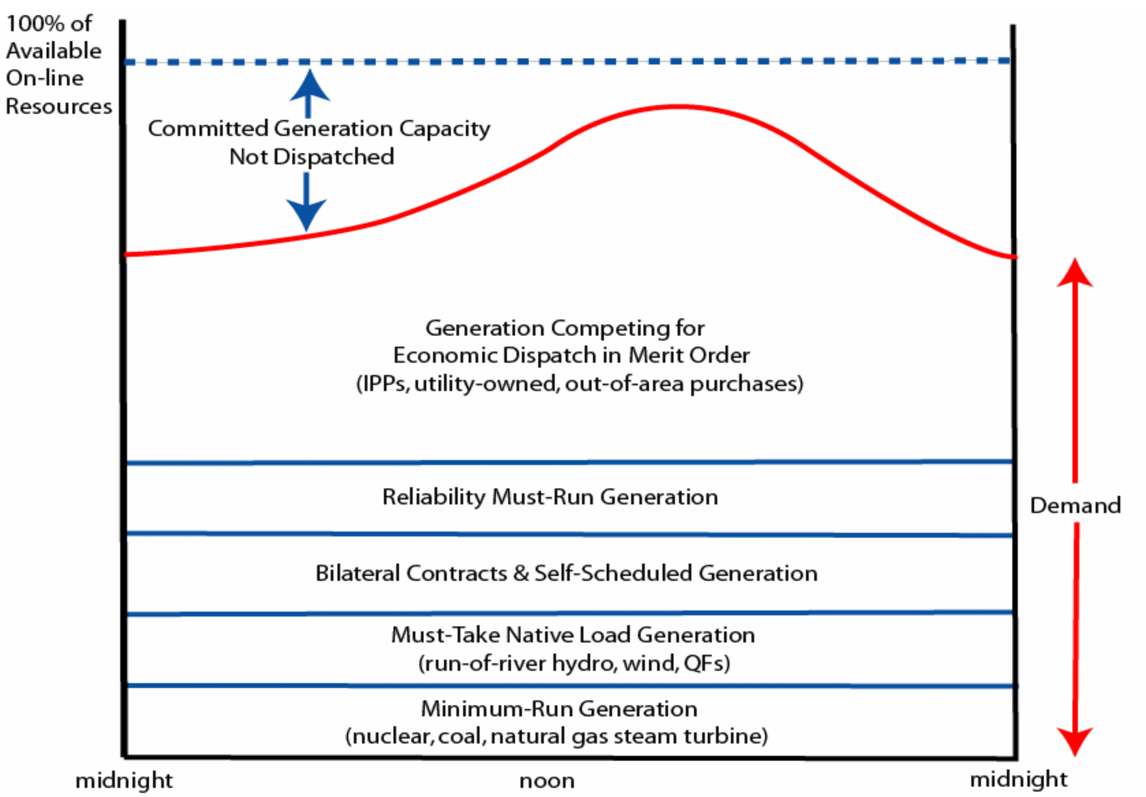
VII. ECONOMIC DISPATCH OF PSE'S ELECTRIC GENERATION RESOURCES – INCLUDING MINT FARM AND SUMAS

Q. Please describe the concept of economic dispatch with respect to electric generation.

A. Economic dispatch is the method of facilitating the most efficient, low-cost and reliable operation of a power system through the calculated dispatch of the available generating resources to meet system load or demand. The primary objective of economic dispatch is to minimize the total cost of a portfolio of generating assets while adhering to the operational constraints of the available generation resources.

Economic dispatch focuses on short-term operational decisions, specifically how to best use available resources to meet customers' electricity needs reliably and at lowest cost. In economic dispatch considerations, every resource is identified with the production levels, costs and operational characteristics *(e.g.,* ramp rates, start-up time and dispatch protocol) specific to the unit. These resources are then placed into a stack of least cost to highest cost – their place in the stack being determined by the production levels, costs and operational constraints associated with the specific resource. Dispatch decisions are then made through this stack with the least cost resources being called upon after the portfolio has dispatched all must-run or must-take resources.

The following chart illustrates the basic composition of an economic dispatch stack. The chart was prepared by the Department of Energy in conjunction with a study provided to Congress regarding the benefits to consumers of economic dispatch procedures. The chart describes the general concept of economic dispatch of generating resources to meet load. The units dispatched first to meet loads are minimum-run (coal and nuclear) and must-take (wind and run-of-river hydro). These units are then augmented by adding in bi-lateral contracts and reliability must-run resources. Finally, the gap (if any) between loads and previously dispatched generation is then made up of economically dispatched units.



Q. How does economic dispatch benefit consumers?

A. Economic dispatch benefits electricity users in a number of ways. In principle, all generation and transmission dispatchers practice economic dispatch to reduce the cost of serving loads. By seeking the lowest cost of energy production to meet electricity demand, economic dispatch reduces total electricity costs. Economic dispatch reduces total variable production costs because load is served using lower-variable-cost generation before using higher variable cost generation (i.e., by dispatching generation in "merit order" from lowest to highest variable cost). Economic dispatch can reduce fuel use when it results in greater use of lower variable cost, higher-efficiency generation units rather than lower-efficiency units consuming the same fuel.

To put it simply, in order to minimize costs, economic dispatch typically increases the use of the more efficient generating units, which can lead to better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less-efficient generation.

Q. What factors are considered when the Company makes economic dispatch decisions?

A. A variety of physical, environmental, operational and regulatory considerations affect how and when resources can, or should be used and combined in the economic dispatch process. The combination of attributes determines how each generating resource is identified and treated in the process. Those factors that are considered in determining economic dispatch may include:

- Market heat rate;
- Unit or generator heat rate;
- Energy-production capacity;
- Variable operations and maintenance costs;
- Start-up costs;
- A unit's mechanical or economical upper and lower production levels;
- Unit ramp rates within the range of production levels (e.g., the time it takes to move from one production level to another while respecting the turbine's safe thermal gradients);
- Minimum sustained production levels (to keep the unit available for the next hour or next day);
- Emissions limits and costs of emission allowances (because units that use up their emissions allowances prematurely may not be available to operate during peak periods);
- A unit's availability on the date and time in question (which might be affected by factors such as inclement weather, prior performance problems, planned maintenance or fuel availability);
- System reliability criteria. There may be times, for reliability purposes, a generator is dispatched out of merit order to provide additional reserves or voltage support to an electric system; and
- Wind integration. There may be times, for wind integration purposes, that a generator is dispatched out of merit order to provide energy to shape wind generation.

Q. Please explain the difference between Unit and Market Heat Rate.

A. Generator or unit heat rate is used to calculate how efficiently a specific generator uses energy. It is expressed as the number of British termal units ("Btus") of heat required to produce a kiloWatt-hour of energy. Operators of generating resources can make reasonably accurate estimates of the amount of heat energy for a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy. For example, a unit heat rate of 10,000 Btu per kWh is representative of a generating resource requiring 10,000 Btu of fuel to generate one kWh of electricity.

Market heat rate is a measurement to assess the likelihood of a generating asset being dispatched. Market heat rate is defined as the market price of power in a particular region divided by the market gas price (including transportation) for that region. The measurement unit given to market heat rate is Btu per kiloWatt-hour (Btu per kWh). For PSE, the prevailing market price points for the market heat rate calculation are: Sumas (Huntington) for natural gas prices and Mid-C for power prices. The market heat rate reflects the efficiency of the generating resource deemed to be the marginal unit for the time period being measured. If the market heat rate exceeds the unit heat rate the unit would be dispatched based upon the economics. For example, the adjusted unit heat rate for Mint Farm is 7.5 million Btu ("MMBtu") per MWh. If power prices are $40.00 per MWh and gas prices are $4.00 per MMBtu, the market heat rate is 10 MMBtu per MWh. In this example, since Mint Farm's heat rate is less than the market heat rate, the cost of running the unit is less than the cost of purchasing the power in the market and the unit will be economically dispatched.

Q. Are there times when a generating unit such as Mint Farm or Sumas would be

dispatched or displaced out of merit order?

A. Yes. There may be reliability constraints or transmission congestion that might require the unit to run out of merit order, or conversely have generation reduced in order to maintain system reliability. For PSE and for example, the Mint Farm plant, this could occur in the winter months where there are transmission constraints east to west across the Cascades. In this scenario PSE could be forced to run the plant out of merit order to ensure that loads are met. Similarly, there are seasonal transmission constraints of BPA's transmission system west of the Cascades. BPA, as the transmission operator, could call upon PSE to generate or back-down generation at Mint Farm to provide needed transmission congestion relief.

Q. If Mint Farm and Sumas had been in PSE's power portfolio over the past two calendar years how would the plants have been dispatched?

A. As discussed previously, the dispatch decision is based upon a number of factors, the prevailing market prices of natural gas and power being critical. Comparing that market heat rate to Mint Farm's adjusted unit heat rate (adjusted for Variable O&M and using a simple calculation that assumes daily dispatch if the market heat rate was greater than the adjusted unit heat rate) indicates that during calendar years 2007 and 2008, Mint Farm could have been dispatched 85.5% of the time during on-peak hours. From January 2007 until its online date August 22, 2008, Sumas could have been dispatched 52.1% of the time during on-peak hours. This is shown in the chart in the Fifth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DEM-6C).

Q. How have Sumas and Mint Farm been dispatched since PSE purchased the plants?

A. Sumas was purchased and placed in service July 25, 2008. Mint Farm was purchased and placed in service in early December 2008. After each plant was placed in service, the Company took them offline for capital and maintenance improvements to bring each of them to Company operating and insurance standards. Sumas has been dispatched 52% and 46% of the on- and off-peak hours, respectively, between the date it was brought back online, August 22, 2008, and March 31, 2009. Since Mint Farm was brought back online January 19, 2009, through March 31, 2009, the Mint Farm primary unit has been dispatched 61% and 58% of the on- and off-peak hours, respectively. For further information on the Mint Farm acquisition, please see the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT).

VIII. SALE OF EXCESS RENEWABLE ENERGY CREDITS

Q. Please describe the proposed sale of excess Renewable Energy Credits as part of the settlement of the California energy crisis litigation.

A. The Prefiled Direct Testimony of Mr. Eric Markell, Exhibit No. ___(EMM-1CT), discusses events leading up to PSE's opportunity to reach a settlement in PSE's long-disputed California Receivable litigation. As a component of the settlement, PSE proposed a transaction that could involve 2 million MWhs of California Renewable Portfolio Standards ("RPS") eligible electric energy, structured in a monthly banking, firming and shaping product and sold at the Mid-C trading hub. The Company met with the parties together and individually under the supervision of FERC mediators and signed agreements which will be presented to the California Public Utilities Commission ("CPUC") and FERC for approval.

Q. Please describe the Renewable Energy Credits PSE is proposing to sell.

A. The Company receives one renewable energy credit ("REC") – a marketable commodity separate from the attached energy value - for each MWh of generation from an eligible renewable resource. Under the Energy Independence Act (the "Act"), codified as RCW 19.285, PSE is required to produce 3% of its generation from renewable resources by 2012, 9% by 2015 and increasing to 15% by 2020. PSE's wind facilities, Hopkins Ridge and Wild Horse, as well as the Klondike III PPA, are eligible renewable resources which generate RECs. PSE will have excess RECs until the Act's requirements are effective in 2012, at which time the level of excess RECs will decline and perhaps end as the renewable requirements increase in the year 2020.

Q. How may these agreements affect power costs?

A. Assuming these sales are ultimately approved by the CPUC and FERC, these agreements will not affect power costs. The proceeds from the transactions will be accounted for pursuant to the accounting petition in Docket No. UE-070725. Please see the Prefiled Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T), for further discussion of the regulatory treatment of these revenues.

IX. PROJECTED RATE YEAR POWER COSTS

A. Overview of Projected Power Costs for this Proceeding

Q. Please describe how PSE projected its pro forma net power costs in this proceeding.

A. Consistent with prior rate cases, PSE developed projected power costs for the rate year, which for this filing is April 1, 2010 through March 31, 2011. These projections are based on the information available to the Company while preparing this case for filing.

As discussed in the prefiled direct testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T), the resulting rate year forecast power costs were then adjusted to test year levels by multiplying by a production adjustment factor. This production adjustment factor represents the ratio of weather normalized delivered energy loads for the test year to the rate year.

Q. How did the Company project its power costs for the rate year?

A. As in prior cases, PSE used the AURORA hourly dispatch model to project a portion of its net power costs for the rate year. The remaining rate year power costs are calculated outside of the AURORA model and are referred to as “Not in Models” costs.

Q. What is the AURORA hourly dispatch model?

A. The AURORA hourly dispatch model is a fundamentals-based production cost model that simulates hourly economic dispatch of the Company’s generation resource portfolio within the Western Electricity Coordinating Council region. AURORA produces a forecast of the variable operating costs for the Company’s generating resources as well as a forecast of regional power prices. Changes to the Company’s assumptions in, and inputs to, the AURORA model since the Company’s last general rate case for projecting rate year power costs are described below.

Q. Were there any changes in the AURORA hourly dispatch model since the Company's 2007 GRC?

A. Yes; EPIS, Inc., the developer of the AURORA hourly dispatch model, provides periodic software and database updates. The software version of AURORA used in this filing is 9.3.1004. The database used is the North American Database 2008-03 which was issued on October 15, 2008.

Q. Is AURORA version 9.3.1004 the most recent version of AURORA available?

A. No. EPIS, Inc. recently issued Version 9.4 on December 18, 2008, after the Company had begun its power cost modeling for this filing. On April 20, 2009, EPIS, Inc. issued Version 9.5.

Q. Please explain the Company's projected power costs that are not calculated within the AURORA hourly dispatch model.

A. Consistent with prior cases, the Company's projected power costs also include costs that are not calculated within the AURORA hourly dispatch model and are called "Not in Models" cost. "Not in Models" include items such as contract costs for the Mid-C hydroelectric projects, transmission expenses, fixed gas transportation charges, amortization of regulatory assets, mark-to-market for fixed-price gas for power contracts (fixed-price power contracts are included in the AURORA hourly dispatch model), fixed coal supply costs, peaking capacity and exchange costs, fixed capacity charges, wind integration costs, wind mitigation credits, and other power supply costs not included in the AURORA hourly dispatch model.

Q. Has the Company used forward market electric prices in determining the rate year power costs?

A. No. Consistent with prior proceedings, the Company used the forward electric market prices generated by the AURORA hourly dispatch model.

Q. Are there any other changes to the power cost modeling assumptions?

A. Yes. PSE removed the major maintenance costs from the variable operation and maintenance ("O&M") costs of PSE's gas-fired generation resources included in the AURORA model's hourly economic dispatch simulations. Recovery of the maintenance costs is included in the production O&M costs discussed below. The methodology and calculation of the rate year maintenance costs for PSE's gas and oil-fired combustion turbines are discussed in the prefiled direct testimonies of Mr. Story, Exhibit No. ___(JHS-1T) and Mr. Louis E. Odom, Exhibit No. ___(LEO-1CT).

Q. What is the impact of this change as compared to how maintenance costs were recovered in the 2007 GRC?

A. The rate year maintenance costs included in this proceeding are $10.8 million, which are $2.6 million lower than the maintenance costs calculated under the prior methodology.

Q. Please quantify PSE's net power cost projection for this case.

A. PSE's projected rate year net power costs, including production O&M expenses and power cost ratemaking adjustments, are $1,184.4 million. Please see the Sixth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DEM-7) for PSE's projected rate year net power costs. Please also see Mr. Story's Prefiled Direct Testimony, Exhibit No. ___(JHS-1T), for the adjustment of PSE's projected rate year net power costs to a test year level.

B. Power Cost Assumptions

1. Rate Year Power Supply Resources

Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2007 GRC?

A. Yes. A number of changes to the Company's portfolio have already occurred or will occur by or during the rate year for this case. Specifically, the Company has:

(1) acquired or is proceeding with acquisition of the following resources discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT):

a. the Mint Farm gas-fired CCCT (The baseload capacity is rated at 259.8 MW, plus 36.6 MW of duct fire capability, and under emergency circumstances, an incremental 14MW can be produced through steam augmentation – the AURORA model includes 296 MW of capacity);
b. an expansion of the Wild Horse Wind project (44 MW of additional capacity);
c. signing of Qualco Dairy Digester PPA (500 kW of additional capacity);

2) arranged to purchase all of the pipeline quality gas supply, estimated at 4,050 MMBtu per day, produced from a landfill gas recovery project at the Cedar Hills landfill in King County.

3) terminated a 50 MW PPA with Lehman Brothers ("Lehman PPA") upon Lehman's announcement to file Chapter 11 bankruptcy. The Lehman PPA was replaced with a similar structured deal with Credit Suisse. See the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) for further discussion;

4) reflected the expiration of the current Colstrip 1 and 2 coal supply agreement effective December 31, 2009. As discussed in the Prefiled Direct Testimony of Mr. Michael Jones, Exhibit No. ___(MLJ-1T), the replacement contract for the Colstrip units 1 and 2 coal supply becomes effective January 1, 2010.

5) reflected the expiration of the 97 MW capacity contract with

Northwestern Energy on December 29, 2010;

6) reflected the expiration of the BPA Snohomish 12 MW PPA on February 28, 2010;

7) reflected the expiration of the TransAlta Energy Marketing (US) Inc. Locational Exchange Agreement on December 31, 2010;

8) reflected the expiration of the Puyallup Energy Recovery Company, LLC on April 18, 2009;

9) assumed the extension of the PPA to serve the retail load in Point Roberts, Washington through the end of the rate year;

10) extended the Nooksack hydro agreement (2.5 MW) with Puget Sound Hydro LLC through 2014, as discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT);

11) assumed the extension of the Port Townsend Paper Corporation ("PTPC") agreement through at least the end of the rate year (the original agreement expired December 31, 2008, a short-term contract extension expires June 30, 2009 and PSE and PTPC are negotiating a five year contract);

12) reflected net lower generation and costs under the Public Utility District No. 2 of Grant County, Washington ("Grant County PUD") Mid-C contract terms effective November 1, 2009. This contract was approved in PSE's 2006 general rate case, Docket Nos. UE-060266 & UG-060267 (consolidated) (the "2006 GRC"). Specifically, PSE

   a. reduced the rate year generation to reflect PSE's new Grant County PUD contract ownership share. PSE's Wanapum Development and Priest Rapids Development Hydroelectric Projects ownership share decreased from 10.8% and 0.54%, respectively, to 0.64% of the combined Priest Rapids Hydroelectric Project projection;

   b. reflected PSE's full Priest Rapid Displacement Product generation as a result of the district's reduced shortfall to serve its own load (removed the 45% reduction reflected in the 2007 GRC included in anticipation of the district's need for this generation to serve its own load since the 2007 actual load for Grant PUD was significantly less than its forecast);

c. Reduced the rate year generation approximately 17 average MW from the 2007 GRC to reflect the Company's decision not to purchase any Meaningful Priority. Under the contract, purchasers are eligible, but not required, to buy, a percentage of the Reasonable Portion generation (referred to as "Meaningful Priority") at a price determined by Grant County PUD's annual power auction. PSE declined the option for the 2009 calendar year after anticipating an above market auction price due to increasing participation by Power marketers willing to pay a premium for Mid-C power. The actual auction price for 2009 is approximately $72 per MWh based on current water forecasts;

13) reduced the projected rate year generation from the Snoqualmie Falls Hydroelectric Project for Powerhouse #1 (12 MW capacity) effective March 1, 2010 and for Powerhouse #2 (34 MW capacity) effective June 1, 2010, both through at least the end of the rate year. See the Prefiled Direct Testimony of Ms. Kimberly Harris, Exhibit No.___(KJH-1T);

14) extended the agreement between PSE and Occidental Energy Marketing, Inc. for gas transportation between the Rockies region and Sumas through June 30, 2011;

15) participated in BPA's Transmission Network Open Season, acquiring 177 MW of additional transmission capacity;

16) incurred an increase in costs to integrate intermittent renewable resources (wind) into the Company's power portfolio, as discussed above; and

17) updated all rate year power contracts as described above and otherwise to reflect current contract terms and planned maintenance.

Q. Are there other changes to PSE's power supply portfolio that are not included in the rate year power costs?

A. Yes. There are several changes to PSE's power supply portfolio that are not included in the prefiled rate year power costs:

1) As discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) , the Company has signed a 4-year winter on-peak power purchase agreement with Barclays for an additional 75 MW of winter-only capacity. This change to the Company's portfolio will occur after the rate year in this proceeding.

2) PSE is currently seeking approval by the CPUC and FERC for agreements to sell market-sourced system power and associated renewable energy credits. As discussed above, these transactions have no impact on, and therefore have not been included in, the projected rate year power cost calculations. For further details of these transactions, please see the prefiled direct testimonies of Mr. Eric Markell, Exhibit No. ___(EMM-1CT) and Mr. John Story, Exhibit No. ___(JHS-1T), and

3) As discussed in the prefiled direct testimony of Mr. Clay Riding, Exhibit No. ___(RCR-1CT), PSE recently took assignment under an asset management agreement of 6,704 MMBtu per day of deliverability and 140,622 MMBtu of gas for power storage capacity from the Jackson Prairie storage facility. This transaction will be included in rate year power costs when PSE files an update as proposed below.

2. <u>Projected Hydro Availability</u>

Q. What historical streamflow record has PSE used in its net power cost projection in this proceeding?

A. Consistent with the past several rate cases, PSE used the average of the 50-year Mid-C streamflow history from 1929 through 1978 to project power costs for the rate year in this proceeding. Also consistent with the past several rate cases, PSE used historical west side streamflow records for the same period of time for projections related to PSE's owned hydropower on the west side of the Cascade Mountains.

3. Natural Gas Prices

Q. What natural gas prices did the Company use for the rate year in running its AURORA hourly dispatch model?

A. As the Commission noted in its final order in PSE's 2006 GRC, the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[8] Consistent with this order, the Company used a three-month average of daily forward market prices for the rate year for each trading day in the three-month period ending March 20, 2009. The Company input these data into the AURORA hourly dispatch model for each of the months of the rate year.

In addition, consistent with the 2007 GRC, all fixed-price short term rate year power contracts are included within the AURORA hourly dispatch model and fixed-priced rate year contracts for natural gas for its power portfolio are adjusted outside of the AURORA hourly dispatch model in the "Not in Models" calculations. These calculations are required whenever natural gas prices are changed or updated during a proceeding.

Q. Please explain the fixed-priced contracts adjustment.

A. The gas price input to the AURORA hourly dispatch model represents a three-

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[8] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order No. 08 Rejecting Tariff Sheets; Authorizing and Requiring Compliance Filing at ¶104, Docket Nos. UE-060266 & UG-060267 (consolidated) (Jan. 5, 2007).

month average of the forecast *market* rate year gas prices at a certain point in time (in this case, March 20, 2009). Given the Company's extensive hedging protocol, which includes a programmatic component that requires a specified amount of hedging be done each month, rate year power costs must reflect the Company's actual fixed priced gas and power rate year contracts as of that date. This methodology reflects these hedges because forecast rate year power costs consist of two components: (i) costs related to *actual* commitments, and (ii) *forecast market costs* dependent upon the AURORA modeled operational and market fluctuations. Including the fixed-price power contracts within the AURORA hourly dispatch model and marking the fixed-price gas for power contracts to the three-month average rate year gas price input in the "Not in Models" calculation is consistent with the methodology used by the Company in its 2006 GRC, 2007 PCORC and 2007 GRC.

Q. How do projected gas prices for this proceeding compare with the projected gas prices for the 2007 GRC?

A. Use of a single price can be misleading because there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. For purposes of comparison, however, the average gas price at the Sumas trading hub for the rate year is $6.35 per MMBtu (for the three months ended March 20, 2009), which is $2.16 per MMBtu lower than the average $8.51

per MMBtu price included in the 2007 GRC (for the three months ended March 11, 2008). Average rate year gas price comparisons are shown in the table below:

	Average Annual Rate Year Gas Prices			
Rate Case =>	2009 GRC	2007 GRC	2007 PCORC	2006 GRC
3-Mo ave at =>	3.20.09	3.11.08	5.10.07	11.30.06
Rate Year =>	Apr10-Mar11	Nov08-Oct09	Sep07-Aug08	Jan07-Dec07
Sumas	$6.35	$8.51	$7.90	$7.41

Q. Please explain the source of the gas price inputs.

A. Consistent with the prior rate cases, the Company used forward gas and power market price data supplied by Kiodex Global Market Data ("Kiodex"). The Company contracted with Kiodex for forward market price data for specific gas and power trading points and for each of the trading hubs that are input into AURORA.

Q. Does PSE intend to update its projected power costs with updated gas price projections during this proceeding?

A. Yes. PSE intends to update its projected power costs with updated gas price projections because the factors that impact natural gas prices are constantly changing, forward market prices quickly become "stale," and their predictive power with respect to actual future prices decreases with time. Establishing rate year gas prices based on the average of the forward prices for the rate year for a three-month period of time closer to the beginning of the rate year will provide a more accurate projection of rate year gas prices. Therefore, the Company will adjust its requested rate relief with updated forward market data prior to rates becoming effective. The short-term fixed-price power contracts are an AURORA input and the gas for power contracts are an adjustment included in the "Not in Models" calculation. In addition, several of the "Not in Models" adjustments and production operations and maintenance adjustments are dependent on the AURORA generation and prices. These adjustments update automatically in the MS Excel files whenever a new AURORA model run download is included in the files.

Q. What is PSE's proposal to update its projected rate year power costs with updated gas price projections during this proceeding?

A. PSE proposes to file updated rate year power costs to reflect more recent three month average gas prices at least thirty days prior to the other parties' response filings.

Q. How do more recent forecast rate year natural gas prices compare to the three-month average at March 20, 2009?

A. As of April 20, 2009, the three-month average rate year Sumas natural gas price has decreased to $5.98 per MMBtu, a reduction of $0.37 per MMBtu from the $6.35 per MMBtu used to determine the prefiled rate year power costs in this proceeding.

Q. What factors have affected the decrease in natural gas prices from the last rate proceeding?

A. A number of underlying factors have affected natural gas prices from rate year to rate year, and each has applied downward pressure on prices. These factors include:

(1) decreased global demand for energy due to a decline in economic growth;

(2) new exploration and discovery of shale gas throughout North America;

(3) increasing U.S. natural gas production; and

(4) strengthening of the U.S. dollar.

There is currently an upward trend in the forecast for rate year natural gas prices due to increased expectations of an economic recovery and an expected decline in domestic production due to reduced natural gas drilling.

4. <u>"Not in Models" Adjustments</u>

Q. Are PSE's rate year adjustments included in the "Not in Models" calculations consistent with the adjustments presented in the 2007 GRC?

A. Yes. Although all the "Not in Models" adjustments are consistent with the 2007 GRC, the Company has added or made changes to a few of the adjustments:

(i) Rate year power costs have been increased to include $9.4 million for Mercury Control requirements costs for Colstrip units 1 through 4. These costs are discussed in the Prefiled Direct Testimony of Mr. Michael Jones, Exhibit No. ___(MLJ-1T);

(ii) Rate year Mid-C contract O&M costs have decreased $23.6 million due to:

- a reduction in costs to reflect the Company's decision not to purchase Meaningful Priority available under the Grant PUD contract as discussed earlier,

- higher revenues from the auction sale of the Reasonable Portion under the Grant PUD contract. PSE receives a portion of the net revenues in excess of what is needed by Grant PUD for its own load. These revenues were higher than reflected in the 2007 GRC due to a higher auction price and lower forecasted unmet load in Grant County, and
- increased O&M and debt costs for Chelan and Douglas PUDs.

(iii) Rate year power costs have been increased $0.1 million to reflect the amortization of the prepaid dedication fee for the Colstrip units 1 and 2 coal supply agreement which was approved in the Company's 2007 GRC; and

(iv) Rate year transmission costs have increased by $12.2 million primarily due to:

a. the acquisition of Mint Farm;

b. increased wind integration costs for Hopkins Ridge and Klondike III as proposed in the 2010 BPA Power and Transmission rate case customer workshops discussed above; and

c. an additional 177 MW of transmission capacity obtained through BPA's Network Open Season, as discussed above.

5. <u>Production Operations and Maintenance Expense</u>

Q. How has PSE developed its forecast of production O&M costs in this filing?

A. In estimating rate year power costs, PSE has made the following adjustments to its test year (January 2008 through December 2008) production O&M costs:

(1) projected rate year O&M costs of $16.4 million for new resources that were not present during all of the test year (i.e., the Mint Farm generation facility, the Wild Horse Expansion Wind Project, the

Sumas Cogeneration Station and the Hopkins Ridge Infill Wind Project);[9]

(2) projected costs under the Vestas O&M contract for the Wild Horse Wind Project;[10]

(3) projected costs under the Vestas O&M contract for the Hopkins Ridge Wind Project;[11]

(4) projected rate year operating costs of $2.3 million for the Frederickson 1 Generating Station based on projected costs provided by the plant operator, EPCOR, and the rate year expected generation. Maintenance costs are normalized or deferred as discussed below;

(5) projected $10.8 million of rate year maintenance costs below $2 million per occurrence for both simple-cycle and combined-cycle combustion turbines based on a five-year average of forecast costs. Maintenance costs over $2 million per occurrence have been deferred for future rate recovery. In-depth discussion of maintenance costs is provided in the prefiled direct Testimony of Mr. Ed Odom, Exhibit No. ___(LEO-1CT). Cost recovery of maintenance costs is discussed in the prefiled direct Testimony of Mr. John Story, Exhibit No. ___(JHS-1T);

(6) removed the lease costs associated with Fredonia 3 and 4 to reflect PSE purchase of the facility effective December 2009. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) for further discussion;

(7) removed the lease costs associated with Whitehorn 2 and 3 to reflect PSE purchase of the facility effective February 2009. This acquisition was approved in the Company's 2007 GRC;

(8) projected $1.2 million for O&M costs associated with the relicensing requirements for the Snoqualmie Falls Hydroelectric Project;

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[9] The Sumas Cogeneration Station and the Hopkins Ridge Infill wind project were both approved in the 2007 GRC.

[10] This is the first rate proceeding in which the test year includes a full year of costs associated with the Wild Horse Wind Project; therefore, only the Vestas contract costs have been proformed, which result in an increase of $0.4 million.

[11] The Hopkins Ridge Vestas contract, which currently expires November 2010, is assumed to be extended through the end of the rate year. Expected contract costs have been proformed, which result in an increase of $0.7 million.

(9) projected $5.6 million for O&M costs associated with the FERC relicensing of the Baker River Hydroelectric Project;

(10) projected $35.3 million for Colstrip O&M costs based upon forecasted O&M costs provided by the plant operator, PPL Montana;

(11) projected $10.5 million of Colstrip costs associated with a lawsuit settled during 2008. These costs are discussed in the Prefiled Direct Testimony of Mr. Michael L. Jones, Exhibit No. ___(MLJ-1T) and adjusted in the Prefiled Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T) so that the rate year O&M reflects these costs being amortized over a five year period;

(12) normalized settlement amounts of $0.3 million to the Muckleshoot Indian Tribe for fish hatchery costs related to the White River Hydroelectric Project;

(13) removed test year costs associated with the White River Hydroelectric Project; and

(14) removed $2.1 million for test year costs associated with the Crystal Mountain oil spill.

X. COMPARISON OF PROJECTED POWER COSTS TO THE PROJECTED POWER COSTS IN THE 2007 GRC

Q. What are the principal differences between the power cost projections in this proceeding and the power cost projections approved in the 2007 GRC?

A. The power cost projection in this case, including production O&M and ratemaking adjustments, is approximately $39.4 million higher than the power costs projections approved in the 2007 GRC. Please see the Seventh Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(DEM-8C) for a comparison of the projected power costs and generation for the 2007 GRC rate year (November 2008 through October 2009) and the projected power costs for the rate year in this proceeding.

Q. What are the causes of the change in projected power costs relative to the 2007 GRC?

A. The following items caused the majority of the change to projected rate year power costs from the 2007 GRC:

(1) decreased Mid-C and owned hydro generation, as discussed above,

(2) decreased Mid-C contract costs due to lower generation received from the Priest Rapids Hydroelectric Project in addition to higher Reasonable Portion revenues from Grant PUD, as discussed above,

(3) increased Colstrip coal costs due to mercury control requirements, as discussed above,

(4) increased Colstrip generation due to a single major maintenance outage scheduled for the rate year as compared to two major scheduled outages in the 2007 GRC power cost forecast,

(5) an addition of 36 average megawatts of forecast load,

(6) lower rate year average gas prices and AURORA-derived rate year market power prices, as discussed above

(7) increased fixed gas transportation and power transmission costs associated with the acquisition of the Mint Farm facility,

(8) increased wind generation,

(9) increased wind integration costs as discussed above, for the Hopkins Ridge and Klondike III projects,

(10) updates for new, existing and expiring purchase power agreements,

(11) increased amortization costs,

(12) increased production O&M due to new resources and costs associated with the Colstrip lawsuit settled in 2008, as discussed above.

XI. CONCLUSION

Q. Please summarize your testimony.

A. PSE actively manages the power and gas cost risks faced by its customers in order to keep power costs as low as reasonably possible. The Company's projected rate year power costs for this proceeding, $1,184.4 million, are consistent with, and based on, sound assumptions using methodologies approved by the Commission in the Company's prior general and power cost only rate cases.

Q. Does that conclude your testimony?

A. Yes, it does.