EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-07___/UG-07___
2007 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-07____** **Docket No. UG-07____**

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

REDACTED VERSION

DECEMBER 3, 2007

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 revised hedging strategies;

(iii) the Company's activities with respect to Renewable Energy Credits ("RECs") and Carbon Financial Instruments ("CFIs");

(iv) the Company's projected rate year power costs for this proceeding; and

(v) 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 power-cost only rate case in Docket No. ___(UE-070565) (the "2007 PCORC").

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.

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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

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. Please see the prefiled direct testimony of Ms. Kimberly J. Harris, Exhibit No. ___(KJH-1HCT), for an overview of PSE's gas portfolio.

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. To the extent that 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. Please see the prefiled direct testimony of Ms. Kimberly J. Harris, Exhibit No. ___(KJH-1HCT), for an overview of the Company's power supply portfolio. Although there are many complex variables

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Ms. Kimberly J. Harris, Exhibit No. ___ (KJH-1HCT), for a discussion of the power and gas portfolios.

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 hydroelectric supply.

A. During an average streamflow year, approximately thirty percent of PSE's electric energy production comes from hydroelectric resources. During poor streamflow conditions, PSE may need to acquire replacement 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 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 where the winter peak is higher than the summer peak. As a result, 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 of load/temperature uncertainty can be significant. While still a winter peaking region, the Pacific Northwest is now also experiencing summer peaking demand, as was witnessed during a heat wave in late July 2006. This is evidence of a higher saturation 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. PSE also has 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 below, PSE relies on nearly 2,375 MW (nameplate) of thermal generating units to help meet its customer loads. These units include approximately 660 MW of large base load coal generators with low variable fuel costs; approximately 1,100 MW of gas combined-cycle combustion turbine co-generators with moderate heat rate conversions; and approximately 600 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generators.

Thermal Generation Units	
	Capacity (MW)
Coal	658
Goldendale	277
Fredrickson	134
Encogen	170
Sumas	133
NUGS	390
Simple Cycle CTs	606
Total Megawatts	2,368

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

Q. Please explain the variability of wind generation.

A. PSE's power portfolio benefits from over 400 megawatts of wind generation capacity. Wind resources, however, have great variability surrounding the short-term wind generation forecasts compared to actual generation. PSE manages this short-term generation variability by reshaping its contracted Mid-Columbia ("Mid-C") hydro generation to accommodate the wind projects' power variations. Such reshaping affects PSE's power costs as hydro generation is adjusted on a real-time basis to accommodate fluctuations in wind generation.

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

A. Pipeline outages, curtailment of transmission rights due to de-ratings,[2] and forced outages are examples of transmission and/or transportation risk. For example, if power cannot be wheeled[3] from the Mid-C trading hub, the Company may dispatch resources that are 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 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

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

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, policies and limits governing energy portfolio management activities;
- Production cost modeling techniques that develop a one hundred 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;

[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.

- 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 the 2006 general rate case, Docket Nos. UE-060266 & UG-060267 (consolidated) (the "2006 GRC")?

A. Yes. As discussed in the 2007 PCORC, the Company has extended the term of the power hedging strategy from [redacted] to [redacted] months and has augmented the active position management period from the first [redacted] months to the first [redacted] months. This revised strategy has the following same features as PSE's prior hedging strategy:

(1) required ratable reductions of monthly commodity exposure each month;

(2) market fundamentals inform monthly hedging volume and intra-month timing for hedging; and

(3) hedging targets based on the minimum or maximum amount of commodity exposure allowed under the Company's Energy Hedging and Optimization Procedures.

The revised programmatic plan requires that the Company make the bulk of the hedging strategies and transactions on or before [redacted] months ahead of delivery (the active position managed period). The revised programmatic plan also employs a "Rolling [redacted] Month Hedging Plan" for periods of time beyond the [redacted] month period prior to delivery, making the cumulative term a total of [redacted] months. Please see Exhibit No. ___(DEM-3C) for an overview of PSE's current hedging strategies. Please also see Exhibit No. ___(DEM-4C) for an Energy Cost Risk Management presentation made to Commission Staff regarding the Company's hedging strategies.

Q. Has the Company made any changes to its Core Gas hedging strategies?

A. Yes. The Company has also extended the term of the core gas hedging strategy from [redacted] to [redacted] seasons, which means that it has also been extended out to [redacted] months.

Q. Why did the Company make these revisions?

A. Prior to extending the term of hedging strategies, the Company engaged in a best-practices benchmarking and market research initiative. These initiatives indicated that (i) customers prefer a longer term period of rate stability and (ii) other utilities engaged in longer term hedging practices than PSE. PSE determined it could be beneficial to expand the Company's hedging horizons. The $350 million credit facility, which supports hedging activities and which was approved in the 2006 GRC, provides the Company increased flexibility to monitor and address the exposures associated with its power and core gas portfolio positions. Please see the prefiled direct testimony of Mr. Donald E. Gaines, Exhibit No. ___(DEG-1T), for an overview of the $350 million credit facility.

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IV. RENEWABLE ENERGY CREDITS AND CARBON FINANCIAL INSTRUMENTS

Q. Please provide a brief overview of the energy requirements in the State of Washington.

A. In November 2006, the citizens of Washington State passed Initiative 937, which established the Energy Independence Act (the "Act"). The Act, codified as RCW 19.285, requires the state's largest electric utilities to (i) supply certain portions of their electricity sales from eligible renewable resources within specific time periods and (ii) pursue low-cost energy conservation opportunities. The Act mandates that 3% of a utility's generation must be produced from renewable resources by 2012, with targets getting progressively higher until reaching 15% by 2020. Resources that qualify as "renewable" under the Act include, for example, wind, solar, biomass, geothermal and low impact hydro.

Q. What is a renewable energy credit?

A. A renewable energy credit ("REC") represents the environmental attributes of one megawatt hour ("MWh") of generation from an eligible renewable resource. A REC is a marketable commodity, which is separate from the attached energy value. Currently, the REC market in Washington is "voluntary" because the effective date of the renewable energy requirements established by the Act is several years away. Many Western states, with the exception of California, also have renewable energy requirements (commonly referred to as "renewable portfolio standards") with target goals some years out. As a result of the gradual phase-in of the Act's renewable energy requirements, entities like PSE are usually surplus RECs in the near term and have no immediate need to procure additional RECs.

Q. What is "Green-e certification"?

A. The REC itself is not a physical commodity, and a single REC, absent any protection, could be conceivably sold to, claimed by, or retired by multiple parties. Multiple use of a single REC is commonly referred to as "double counting" and is strictly prohibited.

The leading independent consumer protection program – provided by the Center for Resource Solutions – offers certification and verification of REC products to ensure that each individual REC is not being "double-counted". This type of certification and verification is referred to as "Green-e certification", and absent Green-e certification, there is little market value for the REC.

Q. Can the Company market Green-e certifiable RECs from its wind projects?

A. Yes. The Center for Resource Solutions approved PSE's application in July 2007, and the Company can now market Green-e certifiable RECs from its Washington wind facilities.

Q. What is required for Green-e certification of RECs?

A. Participation in the Center for Resource Solutions Green-e certification program requires PSE to conduct an annual verification process performed by an independent third-party accountant or auditor, whereby the Company is required to demonstrate that transactions executed during the previous year comply with the Green-e national standard.

Q. How has PSE monetized its RECs generated from the Hopkins Ridge and Wild Horse Wind Projects?

A. In June 2006, PSE signed a non-exclusive brokerage and consulting services agreement with [redacted]. to garner market information in this developing market. Over the latter half of calendar year 2006, PSE closely monitored the REC market and actively prepared internal systems, such as the development of a REC tracking system, to capture such transactions.

On December 21, 2006, PSE's Energy Management Committee approved the sale of RECs generated from the Hopkins Ridge and Wild Horse Wind Projects that were in excess of the Company's renewable energy requirements imposed by the newly passed Initiative 937.

In January 2007, the Energy Management Committee approved the sale of up to [redacted] RECs with a [redacted] vintage year and an initial sale of up to [redacted] RECs with a [redacted] vintage year. In February 2007, the Company's Phase 1 membership with the Chicago Climate Exchange (discussed below) was formally announced and a press release was issued. Because counterparties and the Center for Resource Solutions (the involved independent REC certification provider) raised a concern that [redacted] vintage year RECs were able to be double counted under the membership of the Chicago Climate Exchange's Phase 1 program, the Company took steps to both participate in the Chicago Climate Exchange's Phase 1 program and deliver the previously transacted RECs to affected counterparties. To do this, the Company agreed to provide the affected counterparties with [redacted] vintage RECs instead of [redacted] vintage RECs, honoring the same pricing and quantities as previously agreed upon. The Energy Management Committee's approval for this change was obtained at the April 20, 2007 meeting.

At the July 20, 2007, Energy Management Committee meeting, PSE staff recommended and received approval to monetize additional RECs from vintage years [redacted] and [redacted]. Consistent with this recommendation, Staff monetized [redacted] additional vintage [redacted] RECs, and [redacted] vintage [redacted] RECs.

In September 2007, the Energy Management Committee also approved PSE staff's proposal to monetize future RECs through a proposed programmatic hedging strategy.

Q. Please explain why PSE does not forward-sell all of the projected RECs associated with the output of the Hopkins Ridge and Wild Horse Wind Projects.

A. PSE estimates that the combined output of the Hopkins Ridge and Wild Horse Wind Projects will generate approximately [redacted] RECs annually. However, PSE does not intend to forward-sell the entire estimated amount of RECs generated from these two projects during any year. If PSE were to forward-sell the entire estimated amount of RECs generated from these two projects during any year, the Company would expose itself to risk resulting from the inherent variability in wind generation and other unforeseen circumstances, such as transmission curtailments and weather-related events.

For example, assume the Company forward-sold all estimated [redacted] RECs for a given calendar year to a given counterparty, and the Company's wind facilities actually generated only [redacted] RECs. In such a scenario, the Company would be contractually obligated to make the counterparty whole by procuring the remaining [redacted] RECs in the market, regardless of price. Therefore, forward-selling an amount of RECs that is more than a minimum amount the Company is confident will actually be generated exposes the Company to an unknown amount of risk in a developing market.

In addition, the Company's REC strategy is rather short-term, given that Washington State's renewable energy requirements mandate will be effective beginning in 2012. At such time and thereafter, the Company will be required to meet Washington's renewable energy requirements, and the amount of excess RECs generated from the two wind plants available for sale (if any) would decrease.

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Q. Please compare the amount of actual wind generation from the Hopkins Ridge and Wild Horse Wind Projects in calendar year 2006 to the forecasted amount of wind generation for calendar year 2006.

A. The combined actual wind generation for the Hopkins Ridge and Wild Horse Wind Projects during calendar year 2006 was approximately [redacted] MWh less than the forecast amount, or approximately [redacted]% less than projected. This was due in substantial part to a curtailment by Bonneville Power Administration ("BPA") of the Hopkins Ridge Wind Project transmission line during calendar year 2006. As a result of this curtailment, the maximum available output from the Hopkins Ridge Wind Project was reduced from May through October 2006; therefore, the Hopkins Ridge Wind Project's 2006 generation was much less than projected. Had the Company forward sold all of the forecast output from its wind facilities, the Company would have found itself in a deficit position, and would have had to rely on the market to buy the [redacted] RECs at the prevailing market price to fulfill its obligation to the counterparty.

Q. Why did PSE elect to use a broker to sell these RECs as opposed to selling directly to other utilities or counterparties?

A. PSE elected to use a broker for a number of reasons. First, without a multi-state Pacific Northwest renewable portfolio standard mandate in place, there was no compliance requirement that would bring Pacific Northwest utilities into the REC market to transact PSE's vintage [redacted] RECs. The only Pacific Northwest state with an aggressive renewable portfolio standard target in the near term is California. In addition, given the nascent REC market, PSE believed a broker could better match PSE with qualified buyers.

Unlike the developed power and gas markets in which PSE participates, the REC market typically attracts much smaller counterparties. Generally, these types of counterparties either purchase RECs for resale to end use customers or purchase RECs to support their corporate commitments. Finding these types of buyers without a broker's facilitation services is challenging, and a broker is better situated in an emerging market to match PSE with qualified buyers.

Q. What REC sales has PSE transacted to date?

A. As of October 31, 2007, PSE has billed, committed to or has pending transactions to monetize [redacted] million of RECs from its Hopkins Ridge and Wild Horse Wind Projects for vintage years [redacted] and [redacted] The [redacted] in billed sales from these transactions to date are considered unearned and have been deferred in a regulatory liability account 25300781, "Unearned Rev-Renewable Energy Credit-Wind". The net amount of such account, after deducting the brokerage fees associated with the sale of such RECs, is [redacted] as of October 31, 2007. Currently, PSE is awaiting a decision by the Commission to determine to what use these proceeds will be put. Please see Exhibit No. ___(DEM-5C) for a table of the Company's billed, committed and pending REC transactions.

Q. Please explain the Company's participation in the Chicago Climate Exchange.

A. In February 2007, the Company formally joined the Chicago Climate Exchange ("CCX") as a Phase 1 member; Phase 1 membership is limited to years 2003-2006. Members of CCX make a voluntary but legally binding commitment to meet the annual emission reduction targets. Those members that reduce their emissions below the target have surplus allowances to sell, and those members who emit above the targets comply by purchasing Carbon Financial Instruments from other members of CCX. The commodity transacted at CCX is the Carbon Financial Instrument ("CFI") which represents the equivalent of 100 metric tons of CO2.

After the Company's membership was announced in February 2007, PSE began the process of preparing and submitting data to a third party auditor for all of the thermal assets the Company owned – including partial ownership – during the years 1998 through 2001.

Q. Has the Company monetized any Carbon Financial Instruments?

A. As of the date of this filing, the Company has not sold any Carbon Financial Instruments. At the July 20, 2007 Energy Management Committee meeting, the committee approved transacting Carbon Financial Instruments pursuant to the hedging strategy presented at that meeting. This strategy recognized there were many unknown variables associated with transacting Carbon Financial Instruments transactions, such as no clear market fundamentals, uncertainty regarding third party audit results with respect to the Company's position, and no definitive end date to monetize any allowances that the Company could receive pursuant to the results of the audit. As a result of the unresolved issues surrounding these variables, the Energy Management Committee approved the recommendation in August 2007 to defer the sale of Carbon Financial Instruments until the Company receives conclusive audit results.

V. 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 filing.

A. Consistent with prior rate cases, PSE developed projected power costs for the rate year, which for this filing is November 1, 2008 through October 31, 2009. 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-1CT), the resulting rate year forecast power costs were then adjusted to test year levels by multiplying by an adjustment factor. This adjustment factor represents the ratio of weather normalized delivered energy loads for the test year to the rate year. *See id*. Mr. Story then used that and other data to develop the revenue deficiency for the rate year. *See id.*

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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. The Company's assumptions in, and inputs to, AURORA for projecting rate year power costs are described below.

Q. Were there any changes in the AURORA hourly dispatch model?

A. Yes, EPIS, Inc., the developer of the AURORA hourly dispatch model, provides periodic software and database updates. The version of AURORA used in this filing is 8.5.2019.

Q. Is AURORA version 8.5.2019 the most recent version of AURORA available?

A. No. EPIS, Inc. recently issued a new project file and database: AURORAxmp version 9.0 and North American Database 2007-02. Given time constraints, PSE is not planning to update the AURORA hourly dispatch model in this filing for this more recent information.

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

A. Certainly. 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.

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Q. Has the Company considered using forward electric market prices to determine power costs?

A. The Company considered the use of forward electric market prices to determine power costs, as well as other issues, with interested parties in the Power Cost Only Rate Case Collaborative ("PCORC Collaborative"). At the most recent PCORC Collaborative meeting on November 16, 2007, the group determined it could not come to an agreement on issues discussed in the PCORC Collaborative, including whether rates should be set with forward market prices or with AURORA generated prices. Please see the prefiled direct testimony of Mr. John H. Story, Exhibit No. ___(JHS-1CT), for more discussion of the PCORC Collaborative.

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

A. PSE's projected rate year net power costs, including production operation and maintenance ("O&M") expenses and power cost ratemaking adjustments, are $1.135 billion. Please see Exhibit No. ___(DEM-6) for PSE's projected rate year net power costs. Please also see the prefiled direct testimony of Mr. John H. Story, Exhibit No. ___(JHS-1CT), for the adjustment of PSE's projected rate year net power costs to a test year level.

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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 PCORC?

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 the following resources discussed in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT):

   a. the Hopkins Ridge Wind Infill Project (7.2 MW of additional capacity);

   b. a 20-year power purchase agreement with PPM Energy's Klondike III Wind Project (50 MW of additional capacity);

   c. a 4-year winter on-peak power purchase agreement with [redacted] Corporation (150 MW of additional capacity);

   d. a 4 1/4–year power purchase agreement with Lehman Brothers (50 MW of additional capacity);

   e. a 4 1/4–year power purchase agreement with Sempra Energy Trading (75 MW of additional capacity); and

   f. the Sumas Cogeneration Station under a projected negotiated settlement with Sumas Cogeneration Company, LP (133 MW of additional capacity).

2) signed a 3 ½-year Locational Exchange Agreement with TransAlta Energy Marketing (US) Inc. (totaling 4,718,575 Megawatt Hours), as discussed in more detail below;

3) extended its agreement with Powerex Corporation to serve the retail load in Point Roberts, Washington, through September 2009, as discussed in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT). In addition, the rate year power costs assume an extension of this contract through the end of the rate year,

October 2009;

4) assumed an extension of the agreement between PSE and Occidental Energy Marketing, Inc. for gas transportation between the Rockies region and Sumas through at least the end of the rate year (the agreement currently expires June 30, 2008);

5) assumed an extension of the Port Townsend agreement through at least the end of the rate year (the agreement currently expires on December 30, 2008);

6) assumed an extension of the Nooksack agreement through at least the end of the rate year (the agreement currently expires on November 30, 2008);

7) removed the Puyallup Energy Recovery Company agreement to coincide with the expiration date of April 18, 2009;

8) removed the costs associated with the Encogen auxiliary boiler due to the termination of the Steam Sales Agreement with Georgia Pacific;

9) reduced the benefit from the Priest Rapids Hydroelectric Project due to forecast load growth of Public Utility District No. 2 of Grant County, Washington;

10) reduced the projected rate year generation from the Snoqualmie Falls Hydroelectric Project for Powerhouse 1 (12 megawatt capacity) beginning April 1, 2009 and for Powerhouse 2 (34 megawatt capacity) beginning June 15, 2009, both through at least the end of the rate year. See the prefiled direct testimony of Ms. Kimberly J. Harris, Exhibit No. ___(KJH-1HCT);[4] and

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

[4] The Snoqualmie Falls Hydroelectric Project will be undergoing planned refurbishment construction activities required under the FERC license during the rate year. In its 2007 PCORC filing, the Company projected that Powerhouse 2 would be off-line for over two years beginning March 2008. Since the 2007 PCORC filing, the maintenance schedule has been updated and indicates that outages are now likely to begin in 2009.

Q. Are there any other clarifications you would like to make regarding PSE's rate year power supply portfolio for this proceeding?

A. Yes. PSE's rate year power supply portfolio for this proceeding reflects the following items, which were previously discussed in the 2007 PCORC filing:

1) the expiration of several long-term physical and financial gas contracts, totaling 25,000 MMBtu per day, effective June 30, 2008; and

2) the exclusion from rate year resources of the 20-year purchased power agreement between PSE and OrSumas, LLC for the nearly five megawatt capacity output of the Northwest Pipeline recovered heat generation resource in Sumas, Washington;[5] .

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

A. Yes. PSE removed the AURORA model's transmission losses and costs between the Mid-Columbia ("Mid-C") hub and PSE's west of the cascades zone.

Q. Please explain why the Company made this change to the AURORA model.

A. While we were preparing the power costs for this proceeding, it came to our attention that the AURORA marginal clearing prices for PSE's power costs included transmission costs from the Mid-C hub to PSE's service territory. Upon further research, we found that the AURORA model included transmission losses and costs between geographic "zones" to represent the costs associated with

[5] Although the Commission deemed this resource acquisition prudent in the Company's 2006 general rate case, the developer, ORMAT Nevada, Inc., has indefinitely delayed this project.

delivering energy between geographic areas. In prior AURORA databases, PSE's demand and the resources to meet such demand resided in only one "zone": Oregon, Washington and northern Idaho ("OWI"). As such, PSE's AURORA modeled marginal clearing prices did not reflect the costs to transfer power between zones. In the AURORA database used for this proceeding; however, the OWI zone is now comprised of four zones; each zone's marginal clearing price reflecting the cost of transmission between each zone.

Q. Why is including these AURORA transmission costs an issue?

A. PSE's rate year fixed and variable transmission costs are already calculated and included in the "Not in Model" power costs. Including the transmission costs in the AURORA model database resulted in a double counting of transmission costs. To remedy this situation, PSE removed the AURORA model transmission losses and per megawatt hour transmission cost between the Mid-C hub and the zones that PSE serves.

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

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

A. Consistent with the past several rate cases, PSE used the average of the 50-year Mid-C streamflow history from 1928 through 1977 to project power costs for the rate year. 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.

Q. Why has PSE not used the 60-year streamflow history it proposed in its 2004 general rate case, Docket Nos. UG-040640, et al. (the "2004 GRC")?

A. The Company presented evidence in the 2004 GRC demonstrating that there is no statistical basis to exclude any available historical streamflow data relevant to the Mid-C hydroelectric projects, which at that time was 60 years (1928 – 1987). PSE also demonstrated that the best data to use, if one is to base power costs on a normalized forecast of hydro availability, is the average of the full 60 years of historical Mid-C data. Currently, there are 70 years of such water data available (1928 – 1997).

In the 2004 GRC, Commission Staff agreed with the Company that there is no statistical basis to exclude any available historical streamflow data that is available for the Mid-C hydroelectric projects. However, Commission Staff recommended using a 50-year streamflow history (1928 – 1977) because certain rule curves, such as flood control rule curves, for the latter ten years of the 60-year period, were not developed in a manner that incorporates uncertainty in the use of water.

Although the Company does not believe the rule curves that concerned Staff materially affect the streamflow data so as to preclude use of the 70-year water data in developing a power cost baseline, the Company proposes to accept for purposes of this general rate case the agreed-upon methodology from the 2004 GRC and to continue to use that 50-year streamflow data for this proceeding. This is the same 50-year streamflow data used in the 2006 GRC and the 2007 PCORC.

3. <u>Natural Gas Prices</u>

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 the 2006 GRC, the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial." *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). 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 October 19, 2007. The Company input these data into the AURORA hourly dispatch model for each of the months of the rate year.

In addition, the Company included all fixed-price short term rate year power contracts within the AURORA hourly dispatch model rather than being marked to the AURORA market price in the "Not in Models" calculation. To the extent the Company has fixed-priced contracts in place for natural gas for its power portfolio for the rate year, the Company has continued to adjust for those fixed-priced contracts outside of the AURORA hourly dispatch model.

Q. Please explain the fixed-priced contracts adjustment.

A. The gas price input to the AURORA hourly dispatch model represents a three-month average of the forecast *market* rate year gas prices at a certain point in time (in this case, October 19, 2007). Given the Company's extensive hedging protocol, which includes a programmatic component that requires a specified amount of hedging be done each month, the AURORA hourly dispatch model 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 is consistent with the methodology used by the Company in the 2006 GRC and the 2007 PCORC.

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

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 $8.01/MMBtu (for the three months ended October 19, 2007), which is $0.11/MMBtu higher than the average

$7.90/MMBtu price included in the 2007 PCORC (for the three months ended May 10, 2007). Average rate year gas price comparisons are shown in the table below:

	Average Annual Rate Year Gas Prices			
Rate Case =>	2007 GRC	2007 PCORC	2006 GRC	2005 PCORC Update
3-Mo at =>	10.19.07	5.10.07	11.30.06	4.28.06
Rate Year =>	Nov08-Oct09	Sep07-Aug08	Jan07-Dec07	Jul-Dec06
Sumas	$8.01	$7.90	$7.41	$7.13

Q. What factors have affected the rise in natural gas prices?

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

(i) increased global demand for energy;

(ii) record high oil prices and geopolitical risk;

(iii) liquefied natural gas becoming a more important source of supply;

(iv) increasing U.S. natural gas production;

(v) Canadian imports below historic levels;

(vi) weather uncertainty (hurricanes and cold weather); and

(vii) expected increases in prices in the West due to the Rockies Express Pipeline.

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

A. Consistent with the prior rate cases, the Company used forward price data supplied by Kiodex Global Market Data ("Kiodex") for energy and commodity market data.

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 believe it continues to be appropriate to project natural gas prices for the rate year using forward market data from a three-month period?

A. Yes. Since this issue was discussed extensively in the 2004 GRC, the Company has used a three-month average price to determine gas prices for rate years in the 2005 PCORC, the 2006 GRC, and the 2007 PCORC. PSE believes that the gas prices used to forecast power costs should reflect the best data available regarding gas prices that will actually prevail during the upcoming rate year. Because the price of gas is subject to market dynamics, forward market prices for natural gas are the best available indicator of what the price of gas may be during the rate year.

Concerns addressed by some parties in the past that short-term market dynamics may cause temporary price excursions are appropriately addressed by using an average of forward market price strips over a reasonable period of time – such as the three month average approved and used in the Company's past four rate proceedings.

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

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.

4. Not in Models Adjustments

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

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

(i) Rate year "Other Power Supply" costs, also known as FERC account 557 costs, begin with the test year (October 2006 through September 2007) cost levels and remove the test year amounts for customer deferrals under the Power Cost Adjustment mechanism and costs associated with the green power tag program. In this proceeding, legal costs associated with sales of power ($382,511) have been reclassified to FERC account 923; and

(iii) Two full time equivalents, and resulting employee expenses, have been added to the rate year to address FERC and NERC regulatory requirements.

Q. Are there any other changes to the Not in Models calculations?

A. Yes. BPA has provided notice of its intention to recover, effective October 1, 2008, within-hour balancing costs associated with integrating wind generation into the BPA control area. At the time power costs were prepared for this filing, BPA estimated the intra-hour wind generation balancing costs to be $3.46 per MWh of wind generation. The BPA rate process is expected to be finalized during this rate proceeding, so these costs will be trued up as BPA provides final information. PSE has included approximately $4.1 million in the Company's rate year power costs projections for intra-hour wind integration costs -- $1.8 million for direct costs projected to be paid to BPA for the Hopkins Ridge and Klondike III Wind Projects, and $2.2 million for PSE's intra-hour integration cost for the Wild Horse Wind Project. In addition, the rate year power costs have been reduced by $[redacted] to reflect the wind loss settlement agreement, as discussed in Mr. Story and Mr. Garratt's testimony, Exhibit No. ___(JHS-1CT) and Exhibit No. ___(RG-1HCT), respectively.

5. Production Operations and Maintenance Expense

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 (October 2006 through September 2007) production O&M costs:

i) projected rate year O&M costs of $3.9 million for new resources that were not present during the test year (i.e., the Sumas Cogeneration

Station and the Hopkins Ridge Infill Wind Project);

ii) projected $9.5 million of rate year O&M costs for the Goldendale Generating Station;[6]

iii) projected rate year O&M costs of $10.5 million for the Wild Horse Wind Project;[7]

iv) projected costs under the Vestas O&M contract for the Hopkins Ridge Wind Project;[8]

v) projected rate year O&M costs of $4.9 million for the Frederickson 1 Generating Station based on projected O&M costs provided by the plant operator, EPCOR, and the rate year expected generation;

vi) projected $0.2 million for water supply and wastewater treatment costs for the Encogen Generation Station that were not present in the test year;[9]

vii) normalized O&M for major maintenance for PSE's owned simple-cycle gas and oil-fired combustion turbines ("SCCTs") and PSE's owned Encogen and Fredrickson 1 plants based on operating cost studies and expected rate year generation;[10]

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[6] The Company acquired the Goldendale Generating Station in February 2007, several months after the test year commenced. The Company based its Goldendale Generating Station proforma calculation in this case on the Goldendale Generating Station proforma calculation from the 2007 PCORC. The major maintenance costs for the Goldendale Generating Station reflect the more recent Contract Service Agreement. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) for a discussion of the Contract Service Agreement.

[7] The in-service date for the Wild Horse Wind Project was December 22, 2006, several months after the test year commenced. The Company based this Wild Horse Wind Project proforma calculation on the Wild Horse Wind Project proforma calculation from the 2006 GRC.

[8] This is the first rate proceeding in which the test year includes a full year of costs associated with the Hopkins Ridge Wind Project. Therefore, only the Vestas contract costs have been proformed, which result in an increase of $0.1 million.

[9] PSE will now be responsible for these water supply and wastewater treatment costs because of the expiration of the Steam Sales Agreement with Georgia Pacific.

[10] The rate year major maintenance costs for the SCCTs represent an average annual cost of the expected major maintenance costs over the next ten years and are calculated under a methodology different from the 2006 GRC and the 2007 PCORC. The proposed methodology recognizes that SCCTs do not dispatch often and are utilized to meet peak load demand in higher than expected peaking situations. The existing rate recovery mechanism for major maintenance costs of SCCTs is inadequate because it is

viii) projected lease costs of $6.1 million for Fredonia 3 & 4 to reflect projected lease costs for the rate year;

ix) removed most lease costs associated with Whitehorn 2 & 3 to reflect PSE purchase of the facility effective February 2009. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) for further discussion;

x) projected $1.3 million for O&M costs associated with the relicensing requirements for the Snoqualmie Falls Hydroelectric Project;

xi) projected $3.7 million for O&M costs associated with the FERC relicensing of the Baker River Hydroelectric Project;

xii) projected $35.8 million for Colstrip O&M costs based upon forecasted O&M costs provided by the plant operator, PPL Montana;

xiii) normalized settlement amounts of $0.4 million to the Muckleshoot Indian Tribe for fish hatchery costs related to the White River Hydroelectric Project;

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

xv) removed $2.0 million for test year costs associated with the Crystal Mountain oil spill.

C. <u>TransAlta Locational Exchange Agreement</u>

Q. What is the TransAlta Locational Exchange Agreement?

A. On May 24, 2007, PSE entered into a three-and-a-half year locational exchange agreement whereby PSE will deliver firm energy to TransAlta Energy Marketing

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calculated on an average dollar per MWh run. The recovery of major maintenance costs for the SCCTs should be based on an average annual cost – or over time – rather than on forecast generation. The costs under the proposed methodology are $1.5 million, or $1.4 million of additional costs when compared to the

(US) Inc. ("TransAlta") at Mid-C and simultaneously take delivery of like energy at CW Paul (Centralia) between July 1, 2007 through December 31, 2010. [redacted] for the total energy exchanged throughout the contract term, 4,718,575 MWhs.

Q. What is the background of the TransAlta Locational Exchange Agreement?

A. Over the years, the Company has entered into similar locational exchanges with TransAlta and other counterparties as part of our winter peaking plan. Such exchanges reduce the risk of transmission curtailments from Mid-C to our native load as discussed below. PSE staff engaged in discussions with TransAlta staff to pursue a longer term locational exchange. Discussions went on for nearly ten months before term and price consensus was reached. Because the end date of the agreement was beyond what was then a two year medium term hedging horizon under my management, the agreement was presented to and approved by the Energy Management Committee at its May 17, 2007 meeting.

Q. Why did the Company enter into the TransAlta Locational Exchange Agreement?

A. The benefits associated with the TransAlta Locational Exchange include a power cost [redacted] and delivery to the Company's system on the West side of the Cascades. The Company's Mid-Columbia power purchases are

existing rate recovery methodology.

generally delivered on the East side of the Cascades, and the power must be transmitted or wheeled to the Company's system on BPA's transmission system. Delivery to the Company's system by TransAlta thus decreases reliability risks caused by potential transmission constraints, reduces Mid C wheeling costs and lowers line losses. Please see Exhibit No. ___(DEM-7C) for the TransAlta Locational Exchange Agreement and presentation to and approval from the Energy Management Committee.

VI. COMPARISON OF PROJECTED POWER COSTS TO THE PROJECTED POWER COSTS IN THE 2007 PCORC

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

A. The power cost projection in this case, including production O&M and ratemaking adjustments, is approximately $83.0 million higher than the power costs projections approved in the 2007 PCORC. Please see Exhibit No. ___(DEM-8C) for a comparison of the projected power costs for the 2007 PCORC rate year (September 2007 through August 2008) and the projected power costs for the rate year in this proceeding (November 2008 through October 2009).

Q. What are the causes of the increase in projected power costs relative to the 2007 PCORC?

A. The following items cause the majority of the change to projected rate year power costs:

(i) the expiration of four long-term gas for power contracts that were below current average market price,

(ii) an addition of 34 average megawatts of forecast load,

(iii) increased intra-hour integration costs for the Hopkins Ridge and Wild Horse Wind Projects,

(iv) reduced low-cost coal generation due to two, rather than one, Colstrip major maintenance outages scheduled for the rate year, partially offset by increased coal costs,[11]

(v) updates for new and existing purchase power agreements,

(vi) increased amortization costs,

(vi) increased Mid-C contract costs;

(vii) decreased AURORA modeled power prices, and

(viii) increased production O&M due to new resources, major maintenance and higher projected costs at Colstrip.

It is also noteworthy that the AURORA model projects rate year market heat rates are less than those projected for the 2007 PCORC rate year. In other words, the AURORA model projects for the rate year in this proceeding that it will be relatively more cost-effective than projected for the 2007 PCORC rate year to purchase power rather than to purchase natural gas for power generation purposes. This reduces the generation at PSE's gas-fired generation plants, which in turn increases the level of secondary market purchases within the AURORA hourly dispatch model.

[11] Please see the prefiled direct testimony of Michael L. Jones, Exhibit No. ___(MLJ-1CT), for a discussion of the Colstrip major maintenance overhaul.

VII. 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 – although higher than the projected rate year power costs approved in the 2007 PCORC– 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.