EXHIBIT NO. ___(JMR-1T)
DOCKET NO. ____________
2005 POWER COST ONLY RATE CASE
WITNESS: JULIA M. RYAN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

PREFILED DIRECT TESTIMONY OF
JULIA M. RYAN (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

JUNE 7, 2005

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is Julia M. Ryan. My business address is 10885 N.E. Fourth Street, Bellevue, Washington, 98004-5591. I am the Vice President of Risk Management and Strategic Planning for Puget Sound Energy, Inc. ("PSE" or "the Company"). From December 2001 to March 15, 2004, I served as Vice President Energy Portfolio Management for 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. ___(JMR-2).

Q. What are your duties as Vice President of Risk Management and Strategic Planning for PSE?

A. I lead the Company's Energy Risk Management, Power Supply Operations, and Gas Supply Operations Departments and co-lead Risk Analysis and Planning with the Vice President Finance, Mr. Donald Gaines. In this capacity, my responsibility area manages all PSE short-term and medium-term wholesale power and natural gas portfolios (up to two years), and my area works with Mr. Eric Markell's responsibility area to plan for long-term hedging requirements.

Q. Please summarize the contents of your testimony.

A. I describe the Company's projection of normalized power costs presented in this case. I focus in particular on changes to PSE's power supply portfolio since the Company's last rate case, Docket Nos. UG-040640 and UE-040641 (consolidated), the 2004 general rate case, as well as power cost issues that were contested in that case. I also compare the Company's power cost projections for this case to those the Commission approved in the 2004 general rate case.

II. NORMALIZED POWER COSTS

A. <u>Overview of Projected Power Costs for This Proceeding</u>

Q. Please describe how PSE projected its normalized proforma net power costs in this filing.

A. Consistent with prior general rate cases, PSE developed projected power costs for the rate year, which for this filing is December 1, 2005 through November 30, 2006. These projections are based on the information available to the Company just prior to preparing this case for filing. As discussed by Mr. John Story in his testimony, Ex. No. ___(JHS-1T), the resulting rate year power supply 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. Mr. Story then used that and other data to develop the revenue deficiency for 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 normalized net power costs for the rate year. The AURORA model is a fundamentals-based production cost model that simulates hourly economic dispatch of the Company's generation resource portfolio within the Western Energy Coordinating Council (WECC) region. AURORA thereby produces a forecast of the variable operating costs for the Company's generating resources. Additional information about the AURORA model is provided in the testimony of Mr. Elsea, Exhibit No. ___(WJE-1T). As described below, the inputs to AURORA that the Company used to prepare this case are consistent with the Commission's power cost determinations in the 2004 general rate case.

As in prior cases, the Company's projected proforma power costs also include costs not calculated within the AURORA model, such as projected contract costs for the Mid-Columbia ("Mid C") contracts, transmission expenses, fixed pipeline charges, amortization of regulatory assets, mark to market for fixed contracts, fixed coal supply costs, peaking capacity and exchange costs and other power supply costs.

Q. Is PSE's rate year power supply portfolio for this proceeding different from the proforma power cost portfolio approved in the 2004 general rate case?

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. For example, the Company:

- Will add the Hopkins Ridge wind generating facility ("Hopkins Ridge Project") to its power portfolio;
- Has entered into a two-year power purchase agreement with Arizona Public Service and begun taking delivery of power under that agreement;
- Will begin taking delivery under gas purchase agreements entered into to replace the agreement that CanWest prematurely terminated;
- Will begin generating additional energy at the Frederickson 1 plant from duct firing enhancements to the facility; and
- Has begun generating less power from the Snoqualmie hydroelectric project pursuant to the terms of the new license that FERC approved in June 2004.

In addition, PSE's portfolio will change pursuant to the terms of a number of existing contracts. Specifically,

- The Company's exchange contract with Powerex is expiring February 2006;
- PSE's ownership share under its existing contract with Douglas County PUD for the Wells hydroelectric project has declined from 31.3% to 29.9%, but PSE's costs have increased due to the PUD's settlement with the Colville Confederated Tribes concerning claims related to the

Wells project and the issuance of additional debt for expected capital expenditures, as described in Mr. Markell's testimony;

- PSE's ownership share under its existing contract with Chelan County PUD for the Rock Island II hydroelectric project continues to decline from the current 65% to 55% on July 1, 2005, then on November 1, 2006, declines to 50% through the remainder of the contract term;

- PSE's existing contract with Grant County PUD for the Priest Rapids hydroelectric project expires at midnight on October 31, 2005, and will be replaced by a new contract, as described in Mr. Markell's testimony; and

- PSE has extended the contract with Powerex to serve the Point Roberts, Washington load, as discussed by Mr. Markell.

Q. Do the Company's projected power costs for this case reflect such changes?

A. Yes, the Company's projected power costs for this case reflect such changes as of the time within the rate year that such changes occur. For example, where power received from a hydroelectric contract declines only as of November 1, 2006, the Company's power costs reflect the higher amount of power the Company anticipates receiving per the contract from December 1, 2005 through October 31, 2006. In this example, the decrease would be reflected in the Company's projected power costs only for the last month of the rate year.

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

A. PSE's projected rate year net power costs, including production operation and maintenance expenses and power cost rate-making adjustments, are $875.0 million. *See* Exhibit No. ___(JMR-3). Mr. John Story adjusts this cost to a test period level per his Exhibit No. ___(JHS-4) at 1 and 2, Adjustments 1, 2, 3 and 11).

B. Power Cost Assumptions

1. Hydro

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

A. Consistent with the Commission's February 2005 order in the Company's 2004 general rate case, PSE used the 50-year streamflow history from 1928 through 1977 to project power costs for the rate year.

2. Natural Gas Prices

Q. What natural gas prices did the Company use in running its AURORA model?

A. Consistent with the Commission's order in the Company's 2004 general rate case, the Company projected natural gas prices for the rate year using the average of the forward market prices at Henry Hub over a three-month period ending April 29, 2005, as published on the New York Mercantile Exchange ("NYMEX") futures market. PSE then combined this Henry Hub information with relevant regional basis price differentials, such as Rockies, Alberta (AECO) and Sumas, from the same period, to derive a forward market price for each of the eight market hubs that are input into the AURORA model for each of the months in the rate year.

For purposes of comparison, this method produced an average price at Sumas of $6.54/MMBtu for this proceeding's rate year, compared to the average price at Sumas of $5.60/MMBtu for the 2004 general rate case's rate year.

Q. Does PSE believe that this method of projecting natural gas prices for the rate year continues to be appropriate?

A. Yes. As discussed extensively in the 2004 general rate case proceeding, 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 (as opposed to natural phenomena such as weather or hydro conditions), forward market prices for natural gas are the best available indicator of what the price of gas will 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 in the Company's 2004 general rate case.

Establishing the 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 likely be a more accurate projection of rate year gas prices. Therefore, while PSE used the three-month average of the forward marks ending April 29, 2005 for its direct testimony, the Company will update this data for a three-month period shortly prior to its rebuttal filing in this case and adjust its requested rate relief accordingly.

3. <u>Costs for Peaking Capacity</u>

Q. Did matters other than hydro and gas price assumptions receive particular attention in the 2004 general rate case?

A. Yes. In data requests, hearings and post-hearing briefs, there were questions regarding the Company's inclusion of costs related to winter peaking capacity. Thus, I address this type of cost in some detail below.

Q. What do you mean by the term "costs related to winter peaking capacity"?

A. As described above, the AURORA model predicts hourly *variable* costs of serving *normalized* load – that is, the load that would be expected under "normal" temperatures. Thus, the Company must add costs that Aurora does not model in order to project its rate year power costs. As described in the Commission's order in the 2004 general rate case, the AURORA model does not project costs associated with abnormal temperatures. *See* Order No. 06, Docket Nos. UG-040640 et al. (March 2005) at ¶ 122. However, the Company must be prepared to serve the increased load that occurs when temperatures are colder than normal and must incur costs associated with such preparation.

Q. What projections has the Company made in this case with respect to power costs associated with peak temperatures?

A. The Company has included $0.9 million in projected power costs for winter peaking capacity and $0.9 million for anticipated exchange and short-term firm transmission transactions during the rate year. The Company has also included $4.0 million to cover estimated oil costs for generation to help meet winter loads that exceed the normalized AURORA forecast.

a. <u>Winter peaking contracts.</u>

Q. What peaking capacity costs are projected in the rate year?

A. Consistent with planning for the last winter period, November 2004 through February 2005, we have planned for dual-trigger call options, monthly firm index and supplemental real-time purchases (like self-insurance) for the rate year winter months of December 2005, January 2006, February 2006 and November 2006. *See* Exhibit No. ___(JMR-4C).

Q. What is the basis for the Company's projection of the costs of winter call options?

A. The Company procures winter peaking capacity so that it will be able to serve higher than expected customer loads that occur during an extreme winter peak event. Daily call options contracted for the winter months of November, December, January and February are one of the few products the Company can purchase in the market that can help cover price and volume risks associated with an extreme winter peaking event. The call options are typically structured on a "day-ahead" basis, and provide some disaster insurance for a multiple-day winter peaking event with colder than normal temperatures and a high-priced market environment.

Based on the Company's experience and analysis over the past several years, the Company anticipates procuring "dual-trigger" call options for the rate year winter period, most likely as financially-settled options. A dual-trigger call option has both a price benchmark and a temperature benchmark (also referred to as "strikes"). With a financially-settled option, there is a financial payment made to PSE if the posted market index price at Mid C exceeds the option's strike price and if the actual temperature meets, or is lower than, the temperature strike agreed to between the parties. The payment from the option offsets the costs of purchasing physical power when the temperature falls below the temperature strike. The financial payment acts as a hedge against the actual cost incurred to procure peaking supplies.

Q. How does the Company's projections of winter peaking contract costs in this case compare to the projections approved in the 2004 general rate case?

A. The forecasted cost of procuring additional winter peaking capacity to meet extreme peaking load has decreased from the 2004 general rate case due to a lower forecasted extreme peak load, partially offset by increased premium costs. The methodology for forecasting the extreme peak loads is consistent with the load forecasting methodology used in PSE's recently filed 2005 Least Cost Plan.

b. <u>Firm transmission purchases and transmission exchanges.</u>

Q. What other costs does the Company incur to ensure it has adequate supply to serve customers during an extreme peaking event?

A. In the power market, the preponderance of transactions relevant for PSE occur at the Mid C market. Therefore, during an extreme cold event, the Company makes incremental purchases in the real-time Mid C market if the prices are less than the cost of generating or if additional supplies are needed to supplement the Company's resources. However, there is inadequate transmission capacity to move all of the Company's long- and short-term purchases and incremental purchases during an extreme cold event. Therefore, some precautions must be taken to augment the Company's electric portfolio to ensure deliveries of wholesale supply to the distribution system even during extreme cold winter events.

During an extreme cold event, there is a risk that no short-term firm capacity will be available. Additionally, curtailments of non-firm hourly transmission are likely to occur. Therefore, to ensure the Company has adequate transmission capacity to meet load demand, PSE has developed two strategies to deliver additional winter supply to its system. One is to acquire short-term firm transmission from BPA (which is what the Company did for the winter months of November 2004-February 2005). The second strategy is to enter into "exchange" transactions. *See* Exhibit No. ___(JMR-4C).

Q. What is an exchange transaction?

A. An example of an exchange transaction is where PSE will take delivery from a counterparty at a location where transmission constraints are not expected to occur, such as at the Northern Intertie or at another location west of the Cascade mountains, and simultaneously provide supply to the counterparty at the Mid C in exchange.

c. <u>Combustion turbine oil costs.</u>

Q. Has the Company also included oil costs in its projections to cover winter peaking events?

A. Yes. Consistent with the Commission's order in the 2004 general rate case, the Company has included in its power cost projections the cost to generate with oil at its single-cycle combustion turbine plants. The projected amount of generation is based on actual historical usage over the period 1995 – 2004 at the Fredonia, Frederickson and Whitehorn facilities. This is consistent with the methodology for projecting such costs approved in the 2004 general rate case, except that PSE has updated the historical usage dataset to the most recent 10 years available. *See* Order No. 06, Docket Nos. UG-040640 et al. (March 2005) at ¶ 123. The Company then calculated the projected cost of that oil volume. *See* Exhibit No. ___(JMR-5C).

4. Production Operation & Maintenance

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 production operation and maintenance costs:

i) Proformed the O&M costs of the new Hopkins Ridge Project based on forecasted operation and maintenance costs;

ii) Proformed the O&M costs of the Frederickson 1 resource based upon forecasted operation and maintenance costs;

iii) Normalized O&M for major maintenance for PSE's owned simple-cycle gas and oil-fired combustion turbines and PSE's owned Encogen plant based on operating cost studies;

iv) Restated the test year to remove O&M for the retired White River plant;

v) Proformed the Whitehorn 2 & 3 and Fredonia 3 & 4 lease costs to reflect the lease costs expected in the rate year;

vi) Proformed the O&M costs associated with the FERC relicensing of the Snoqualmie Falls Hydroelectric Project; and

vii) Proformed the Colstrip O&M costs based upon forecasted operation and maintenance costs.

C. Arizona Public Service Purchased Power Agreement

Q. What is the Arizona Public Service Purchased Power Agreement?

A. On June 3, 2004, PSE entered into a two year purchased power agreement

("PPA") for 85 MW of flat, firm energy from Arizona Public Service Company ("APS") beginning January 1, 2005 through December 31, 2006, at a price below the Dow Jones Mid-C index price. The PPA is backed by generation from the Centralia Coal facility and by market purchases made by APS when energy from the Centralia facility is not available.

Q. What is the background of the APS PPA?

A. The opportunity to enter into this PPA arose when APS submitted a proposed two-year PPA to the Company on March 12, 2004, in response to the Company's January 2004 All Source Request for Proposals (RFP), as described in the testimonies of Mr. Eric Markell and Mr. Roger Garratt.

Because resources with durations of two years or less fall under the management of the Company's Energy Risk Management ("ERM") and Power Supply Operations ("PSO") Departments, this potential opportunity was moved to my department for further review and pursuit of final commercial terms. This permitted the Company to more easily compare this proposal to other potential short- to medium-term resource opportunities being considered by ERM and PSO.

Q. Why did the Company enter into the APS PPA?

A. As described in Mr. Markell's testimony, the Company has a current need for additional energy resources. Significant benefits associated with the APS proposal included attractively priced energy, with delivery to the Company's system on the West side of the Cascades. By contrast, as described above, the Company's wholesale short-term power purchases are generally taken at the Mid C trading hub, which is located on the East side of the Cascades, and the power must be wheeled to the Company's system on BPA's transmission system. Delivery to the Company's system by APS thus decreases reliability risks caused by potential transmission constraints, reduces Mid C wheeling costs and lowers line losses. Given the advantages to this delivery point, the below Mid C index price for the APS PPA was particularly attractive.

Moreover, in the event the Company wished to effectively fix the price at some point, an index-based product can be swapped for a product with a fixed financial price.

Q. Please describe the Company's efforts with respect to final review and approval of the APS PPA.

A. My department's staff reviewed the details of the potential transaction with the Company's Risk Management Committee ("RMC") on May 17, 2004. The RMC requested that the department staff seek to obtain offers for comparable products from alternative suppliers in order to double check the attractiveness of the terms.

See Exhibit No. ___(JMR-6HC).

The Company subsequently received offers from three other suppliers. All were inferior to the APS offer in terms of their price and/or delivery point. The RMC authorized the staff to negotiate the best possible deal given certain pricing considerations. These objectives were met, and the Company executed the agreement. *See* Exhibit No. ___(JMR-7HC) and No. ___(JMR-8HC).

III. COMPARISON OF NORMALIZED POWER COSTS IN THIS CASE TO THE COMPANY'S 2004 GENERAL RATE CASE

Q. Why is the Company filing a power cost only rate case at this time when it just completed a general rate case?

A. As detailed below, the Company anticipates that its power costs during the rate year will be higher than the costs currently set in rates. Resetting the Company's Power Cost Rate under the Power Cost Adjustmen ("PCA") Mechanism will send better price signals to PSE's electric customers regarding the cost of the electricity they consume and will reduce financial pressures on the Company caused by these increasing power costs.

It is also important to true up the Power Cost Rate to account for the acquisition of the Hopkins Ridge Project because of the structure of the PCA Mechanism. Absent this filing, the Company would not recover the cost of investment in Hopkins Ridge. Specifically, the PCA Mechanism allows for recovery of new resources at the lower of their actual variable cost or the current Power Cost Rate.

The Company is not permitted to recover additional *fixed* costs through the annual PCA compliance filing accounting without prior Commission approval.

Q. Please describe the principal differences between the Company's forecast of normalized power costs in this case and the forecast of normalized power costs in the Company's 2004 general rate case.

A. Please refer to Exhibit No. ___(JMR-9), which shows a comparison of the normalized power costs approved in the 2004 general rate case to those presented in this case.

This proceeding's total projected power costs have increased due to an additional 70 aMWs of customer load. The additional 50aMWs of generation from the new Hopkins Ridge wind-power plant and the 85aMWs from the APS contract more than offset this increased customer demand. However, as I noted previously, rate year average gas prices are forecast to increase from $5.60/MMBtu to $6.54/MMBtu (at Sumas, with similar increases at other trading hubs), or $0.94/MMBtu; a 17% increase from current rates. This has made it more expensive to run our gas-fired turbines.

Additionally, forward market heat rates, calculated as the ratio of forward power prices divided by forward gas prices, are forecast to be lower, which means PSE's gas generation will be dispatched less frequently and PSE will earn less revenue from off-system sales (called "secondary sales"). This revenue typically helps reduce overall power costs.

In addition, power costs reflect the costs associated with: 1) planned maintenance for the Colstrip units; 2) a full year's impact of the BPA transmission rate increase discussed in the 2004 general rate case applied to all affected transmission schedules; 3) expiration of PSE's exchange agreement with Powerex; 4) escalations in the costs of PSE's Mid C contracts, as described above and in Mr. Markell's testimony; 5) increases in PSE's existing long-term power purchase contracts (annual contract cost escalations are not recovered in the PCA mechanism); 6) proforma increases in production O&M as discussed above; 7) anticipated rate increases in gas transportation contracts; and 8) increased amortization expenses.

Q. What is the total dollar impact of the power cost increases described above?

A. Altogether, the Company's projection of power costs it will incur during the rate year for this case, including production O&M, is approximately $68.9 million higher than what is presently reflected in the PCA Power Cost Baseline Rate as approved in Order No. 06 of the last general rate case, Docket Nos. UG-040640 and UE-040641.

Q. How would rate year projected power costs for this case change if the Hopkins Ridge project were not included as a resource?

A. It is anticipated that PSE would incur an additional $20.4 million in market transactions during the rate year if the Hopkins Ridge resource were not a part of our power portfolio. PSE ran the AURORA model with the same assumptions as for the rate year power costs, except removed the Hopkins Ridge wind project. The model showed that, without the forecasted generation from Hopkins Ridge, PSE would need to purchase additional power in the market at a cost of approximately $20.4 million. *See* Exhibit No. ___(JMR-10).

IV. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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