EXHIBIT NO. ___(DEM-9CT)
DOCKET NOS. UE-090704/UG-090705
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-090704** **Docket No. UG-090705**

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

REDACTED VERSION

SEPTEMBER 28, 2009

PUGET SOUND ENERGY, INC.

PREFILED SUPPLEMENTAL DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

CONTENTS

PUGET SOUND ENERGY, INC.

PREFILED SUPPLEMENTAL DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

I. INTRODUCTION

Q. Are you the same David E. Mills who provided prefiled direct testimony in these dockets on behalf of Puget Sound Energy, Inc. ("PSE")?

A. Yes, I filed prefiled direct testimony, Exhibit No. ___(DEM-1CT) and seven supporting exhibits (Exhibit No. ___(DEM-2) through Exhibit No. ___(DEM-8C)).

Q. What topics are you covering in your prefiled supplemental direct testimony?

A. This prefiled supplemental direct testimony updates the projected rate year power costs presented in my Prefiled Direct Testimony, Exhibit No. ___(DEM-1CT), and supporting exhibits thereto, for changes that have occurred since the assumptions utilized in the original filing on May 8, 2009.

Q. Please summarize this prefiled supplemental testimony regarding the update of power costs.

A. Projected rate year net power costs in this supplemental filing, including production operation and maintenance ("O&M") expenses and power cost ratemaking adjustments, are $1,134.3 million—a $50.1 million decrease from the originally filed power costs of $1,184.4 million. Please see Exhibit No. ___(DEM-10) for the updated power costs. As discussed in the Prefiled Supplemental Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-9T), PSE used these updated power costs, plus other data, to adjust the revenue deficiency for the rate year.

II. UPDATE TO PROJECTED POWER COSTS

Q. Has PSE reconciled the projected power costs filed on May 8, 2009, to the updated projected power costs?

A. Yes. Please see Exhibit No. ___(DEM-10) and Exhibit No. ___(DEM-11C) for reconciliations of power cost projections. The table below also describes the changes to projected power costs for the rate year since the filing of May 8, 2009.

Rate Year Power Cost Forecast

	Costs in thousands		Load (MWhs)
As Filed 05.08.09		$ 1,184,395	23,916,618
Update Load Forecast	$ (41,691)		(932,382)
Gas Price Update to 8.13.09	$ (3,121)		
Colstrip Outage and Business Plan Update	$ (10,034)		
Wheeling - primarily Final BPA Rate Case	$ (4,007)		
New Gas Pipeline Capacity for Power Book	$ 5,553		
Maintenance adjustment for Labor	$ 2,166		
Priest Rapids Hydro Project Update	$ 1,510		
Contract Updates and Other	$ (465)		
Total Change		$ (50,089)	(932,382)
Supplemental 9.28.09		$ 1,134,306	22,984,236

Q. How did PSE update projected power costs for the rate year?

A. PSE updated (i) the projected rate year electric load forecast, (ii) forward market gas prices, and (iii) PSE resources assumption inputs to the AURORA hourly dispatch model. Additionally, PSE updated cost projections outside of the

AURORA model to reflect these and other changes as noted below.

Q. Did PSE make any other changes to the AURORA model database for this supplemental filing?

A. Yes. PSE updated (i) maintenance schedules for PSE-owned and contracted resources ([redacted]), (ii) coal and contract prices to reflect more recent information, and (iii) PSE's contract share of the output of the Priest Rapids Hydroelectric Project. As shown in Exhibit No. ___(DEM-11C), the AURORA modeled power costs for the rate year decreased $62.1 million from the power costs filed on May 8, 2009, due to the updates to forecast load, gas prices, and resource and contract data.

Q. What changes were made to forecast power costs outside of the AURORA model?

A. PSE adjusted costs outside of the AURORA model to reflect (i) the items discussed above, (ii) the final rates from the Bonneville Power Administration's ("BPA") 2010 Wholesale Power and Transmission rate cases ("BPA 2010 Rate Cases"), (iii) a correction to planned maintenance costs, and (iv) new gas pipeline capacity agreements. These changes increased costs outside of the AURORA model, which includes the Not in Models costs, production O&M and regulatory disallowances, by $12.0 million.

A. Electric Load Forecast Update

Q. What electric load forecast did PSE include in the AURORA model for this supplemental filing?

A. As discussed in the Prefiled Supplemental Direct Testimony of Mr. Donald E. Gaines, Exhibit No. ___(DEG-9T), PSE used the forecast delivered electric load forecast from the F2008R load forecast, which PSE's Energy Management Committee approved in July 2009. This load forecast more accurately reflects current economic conditions than the load forecast underlying the power costs filed on May 8, 2009.

Q. What rate year power cost impact was caused by the reduction in load?

A. The forecast electric load reduction of 932,382 MWhs reduced rate year power costs by $41.7 million.

B. Natural Gas Prices Updated

Q. What natural gas prices did PSE use for the rate year in running its AURORA model for this supplemental filing?

A. PSE used a three-month average of daily forward market gas prices for the rate year for each trading day in the three-month period ending August 13, 2009. PSE input these data and the rate year fixed-price short term power contracts in place at August 13, 2009 into the AURORA model for each of the months in the rate year.

This is the same methodology as described in my prefiled direct testimony, Exhibit No. ___(DEM-1CT), except that it uses the more recent three-month period described above.

For purposes of comparison, the updated average price at Sumas for the rate year resulting from use of the updated information is $5.97/MMBtu, which is $0.38/MMBtu lower than the average price of $6.35/MMBtu used in PSE's original filing on May 8, 2009.

In addition, projected power costs have been adjusted outside of the AURORA model to reflect fixed-price natural gas contracts in place at August 13, 2009.

Q. Please explain the change to forecast power costs caused by the update to rate year gas prices.

A. The rate year power costs were reduced by $3.1 million to reflect forecast gas prices at August 13, 2009. This routine update is methodical and includes updating both the AURORA model for the more recent gas prices and for the fixed-price short term rate year power contracts in place at the pricing date, as well as updating the costs outside of the AURORA model—known as Not in Models—to reflect the more recently dated fixed priced short-term natural gas contracts.

C. Colstrip Update

Q. Please explain the change to projected rate year Colstrip costs.

A. PSE and the other Colstrip owners [redacted]. [redacted]. PSE also adjusted the projected rate year Colstrip coal commodity and Colstrip production O&M costs to reflect this maintenance update, current budgets, and other recent information, such as decreased mercury control requirements costs. The Colstrip updates reduced the rate year power costs $10.0 million.

D. Wind Integration and Transmission

Q. Has BPA finalized its 2010 Rate Cases?

A. Yes. BPA has finalized its 2010 Rate Cases and submitted the final rates from that proceeding to the Federal Energy Regulatory Commission ("FERC") for approval and confirmation. PSE has no reason to believe that FERC will not approve and confirm such rates.

PSE updated the rate year power costs to reflect BPA's new transmission rates. Effective October 1, 2009, BPA's wind integration rate will be $1.29 per kW per month—less than half of the $2.73 per kW per month anticipated in the power costs filed on May 8, 2009. Both the Hopkins Ridge Wind Project and the Klondike III Wind Project (PSE has a purchase power agreement for a portion of the output of the Klondike III Wind Project) are interconnected to BPA's Balancing Authority. Rate year power costs have, accordingly, decreased $3.1 million from the original filing due to this rate reduction.

Q. Have wind integration costs within PSE's Balancing Authority also been updated in this supplemental filing?

A. Yes. PSE updated the wind integration costs for the Wild Horse Wind Project, which is located within PSE's Balancing Authority, to reflect the more recent prices discussed above. PSE used updated hourly market prices from the AURORA model to determine the cost of integrating wind in PSE's Balancing Authority, and the rate year power costs were reduced $0.5 million as a result.

E. New Gas Pipeline Capacity Contracts

Q. Please discuss the additional gas for power pipeline capacity contracts.

A. As discussed in the Prefiled Supplemental Direct Testimony of Mr. Clay Riding, Exhibit No. ___(RCR-4CT), PSE is in the process of finalizing additional Northwest Pipeline capacity for its electric portfolio to firm the gas transportation for the gas-fired generator fleet. Specifically, the rate year power costs now include (i) the permanent release of 9,000 MMBtu per day of firm pipeline capacity (the original filing included a temporary release), (ii) an additional 25,000 MMBtu per day of discounted firm capacity effective April 1, 2010, and (iii) 2,000 MMBtu per day of firm capacity effective November 1, 2009. PSE is also currently finalizing arrangements for an additional 20,000 MMBtu per day of Westcoast Pipeline firm capacity. In addition, as discussed in my Prefiled Direct Testimony, Exhibit No. ___(DEM-1CT), costs associated with the additional Jackson Prairie storage capacity obtained through the Asset Management Agreement have now been included in the rate year power costs. Including these new contracts in the rate year power costs and considering currently forecast pipeline and Canadian exchange rates resulted in a $5.6 million rate year power cost increase.

F. Maintenance Costs

Q. Please discuss the changes that PSE made to production O&M expenses.

A. PSE proposed in this proceeding to recover maintenance costs under $2 million per occurrence for both simple-cycle and combined-cycle combustion turbines based on a five-year average of forecast costs. As discussed in the Prefiled Supplemental Direct Testimony of Mr. Ed Odom, Exhibit No. ___(LEO-10CT), PSE has corrected the rate year production O&M costs to include an appropriate allocation of labor expenses with the planned maintenance costs. Accordingly, production O&M costs have increased $2.1 million for the rate year.

G. Priest Rapids Contract Update

Q. Please describe the updates to the power portfolio contracts.

A. PSE's forecast rate year generation from the Priest Rapids Hydroelectric Project included in the AURORA model has increased due to the lower load forecast of Public Utility District No. 2 of Grant County, Washington ("Grant County PUD"). A forecast increase in PSE's Priest Rapids Hydroelectric Project share also translates to higher Reasonable Portion revenues. The benefits of this increased generation is more than offset by a decrease in forecast Reasonable Portion revenues under the Grant County PUD contract due to lower anticipated auction proceeds which reflect more recent, lower market prices.

H. Other Power Cost Updates

Q. Please describe the other updates to the rate year power costs.

A. PSE also updated the rate year power contracts—such as the BPA WNP-3 Exchange purchase power contract—to reflect current contract rates. The power purchase agreement to serve the retail load in Point Roberts, Washington has also been finalized for a five year term and at a lower cost per MWh. Calculations within the Not in Models that are dependent on prices have been updated to reflect the more recent gas prices and AURORA-generated power prices. Production O&M costs, which are synched to the AURORA model generation, have also been updated to reflect the updated AURORA model run. Lastly, as discussed above, the rate year power costs were updated to reflect current planned maintenance schedules.

III. CONCLUSION

Q. Does this conclude your supplemental testimony?

A. Yes, it does.