EXHIBIT NO. ___(DEM-8T)
DOCKET NOS. UE-111048/UG-111049
2011 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-111048** **Docket No. UG-111049**

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

SEPTEMBER 1, 2011

PUGET SOUND ENERGY, INC.

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

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PUGET SOUND ENERGY, INC.

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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 six supporting exhibits (Exhibit No. ___(DEM-2) through Exhibit No. ___(DEM-7C)).

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 June 13, 2011.

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 $982.8 million—a $9.6 million decrease from the originally filed power costs of $992.5 million and a $97.8 million decrease from amounts set in current rates. Please see Exhibit No. ___(DEM-9) and Exhibit No. ___(DEM-10C) for the updated power costs. As discussed in the Prefiled Supplemental Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-11T), PSE has updated the revenue requirement for these updated power costs.

II. UPDATE TO PROJECTED POWER COSTS

Q. Has PSE reconciled the projected power costs filed on June 13, 2011, to the updated projected power costs?

A. Yes. Please see Exhibit No. ___(DEM-9) and Exhibit No. ___(DEM-10C) for a comparison of the updated rate year power cost projections to those originally filed in this proceeding and to those currently reflected in rates.

Table 1 below also describes the changes to projected power costs for the rate year since the filing of June 13, 2011.

Table 1. 2011 GRC Rate Year Power Cost Forecast

	Changes ('000s)	Total ('000s)	Load (MWhs)
As Filed		$992,454	23,172,444
Natural Gas Price Update	$1,652		
Contract Updates-WNP3 & Schedule 91	$717		
Westcoast/Station 2 Mark-to-Market Calculation	($8,009)		
FERC 557 Power Costs Reclassified to A&G	($1,465)		
Klamath Peakers PPA Transmission Update	($1,107)		
BPA 2012 Rate Case Update	($529)		
Transmission Reassignments	($488)		
Wells Hydroelectric Project Contract Update	($136)		
Other Power Cost Updates	($275)		
Total Change		($9,639)	-
Supplemental		$982,815	23,172,444

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

A. PSE updated forward market gas prices and 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. What changes did PSE make to the AURORA model database for this supplemental filing?

A. PSE updated the AURORA model database for (i) the three-month average forward gas prices at July 26, 2011, (ii) short-term rate year power hedges at July 26, 2011, and (iii) rate year contract prices and volumes for purchase power contracts with Bonneville Power Administration ("BPA") related to WNP-3 and with various parties under PSE's Schedule 91 tariff.

As shown in Exhibit No. ___(DEM-10C), the AURORA modeled power costs for the rate year increased $4.0 million from the power costs filed on June 13, 2011, due to these updates.

Q. What changes did PSE make to forecast power costs outside of the AURORA model?

A. PSE adjusted costs outside of the AURORA model – the Not-in-Models costs – to reflect:

(i) a correction and revision to the calculation of the mark-to-market for the price difference (known as the "basis differential") between natural gas sourced at the Station 2 gas hub and natural gas sourced at the Sumas gas hub,

(ii) a reclassification of FERC 557 legal costs associated with transmission to administrative and general expenses,

(iii) the transmission contract signed with Portland General Electric Company for the Klamath Peakers Purchased Power Agreement (the "Klamath Peakers PPA"),

(iv) the final rates from BPA's 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (the "BPA 2012 Rate Case"),

(v) increased forecast transmission reassignment revenues due to increased Point-to-Point ("PTP") transmission,

(vi) updated rate year budget information from Public Utility District No. 1 of Douglas County, Washington ("Douglas PUD") for PSE's share of output from the Wells Hydroelectric Project, and

(vii) other power cost updates.

As shown in Exhibit No. ___(DEM-10C), these changes decreased costs outside of the AURORA model, which includes the Not-in-Models costs, production O&M

and regulatory disallowances, by $13.6 million.

A. Natural Gas Price Update

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 July 26, 2011. PSE input these data and the rate year fixed-price short-term power contracts in place at July 26, 2011, 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 is $4.79/MMBtu, which is $0.07/MMBtu higher than the average price of $4.72/MMBtu used in PSE's original filing on June 13, 2011.

In addition, projected power costs have been adjusted outside of the AURORA model to reflect fixed-price natural gas contracts in place at July 26, 2011.

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 increased by $1.7 million to reflect forecast gas prices at July 26, 2011. This routine update is methodical and includes updating 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 Not-in-Models costs to reflect the updated forecast gas prices and the more recently dated fixed-price short-term natural gas contracts.

B. Contract Updates – WNP-3 and Schedule 91

Q. Please discuss the rate year contract updates included in the AURORA model.

A. PSE has updated AURORA model contract rates and volumes to reflect the annual update to the BPA WNP-3 Exchange contract, which increased both the volumes available under this contract and the cost per megawatt hour ("MWh"). AURORA also reflects the addition of three contracts under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production" that will provide power during the rate year. The AURORA rate year power costs increased by $0.7 million due to these contract updates.

C. Westcoast/Station 2 Mark-to-Market Calculation

Q. Please explain the calculation of the mark-to-market for the basis differential between natural gas sourced at the Station 2 and the Sumas gas hubs.

A. As discussed in Exhibit No. ___(DEM-1CT), PSE has natural gas pipeline capacity under contract with Westcoast Energy, Inc. to transport natural gas between the

Station 2 and the Sumas gas hubs. The AURORA model uses the input Sumas gas prices for PSE's gas fired generators' dispatch and power costs; therefore, PSE must separately consider the cost difference of natural gas between Station 2 and Sumas – the "basis differential" – in the Not-in-Models adjustments. An adjustment to reflect the benefit associated with PSE's acquisition of natural gas pipeline capacity on the Westcoast Energy, Inc. system is included in Not-in-Models.

Q. What changes has PSE made to the mark-to-market calculation in the updated rate year power costs?

A. In addition to the update to the rate year forward gas prices discussed above, PSE has made two modifications to the calculation of the mark-to-market for the basis differential between Station 2 and Sumas. The first change is to correct an error in the as filed power costs; the second is to revise how the Station 2 forward prices are derived.

Q. What correction has been made to the mark-to-market calculation?

A. The rate year power costs included in the direct filing inadvertently calculated the basis differential between the Station 2 hub and the Alberta Energy Company ("AECO") gas hub, rather than compare the cost of gas purchased at Station 2 to the Sumas forward gas prices. PSE has corrected this error in the updated rate year power costs.

Q. What methodology is PSE proposing to derive the Station 2 gas hub forward prices?

A. As discussed in Exhibit No. ___(DEM-1CT), there are no readily available forward gas prices for Station 2, so PSE is proposing to use forward basis differentials contracted from a third party – Wood Mackenzie – to determine the forward gas prices for Station 2. Specifically, Wood Mackenzie provides an independent forward price forecast of the basis differential between the AECO and Station 2 gas hubs. AECO is one of the gas hubs acquired from Kiodex for input to AURORA; therefore, PSE may calculate the monthly Station 2 forward gas prices for the rate year by adding the Kiodex AECO forward gas prices to the Wood Mackenzie basis differential. In this regard, all gas prices used in the determination of rate year power costs would then be based upon forward price forecasts for the rate year period.

Q. Please explain PSE's proposed revision to the mark-to-market calculation.

A. At the time of the direct filing, PSE had not yet received Wood Mackenzie's forward price curves, so PSE used the average of four broker quotes for the forward basis differential between the AECO trading hub and Station 2 in order to determine the rate year gas prices at Station 2. PSE then proposed to update power costs during this proceeding with the contracted basis differentials.

For purposes of determining the monthly price of gas sourced at Station 2 for this updated power cost filing, PSE has added the average of the three monthly Wood

Mackenzie quotes for the rate year basis differential between Station 2 and AECO to the AECO forward gas prices provided by Kiodex. The average of the three month (May through July 2011) Wood Mackenzie quotes for the rate year basis differential between Station 2 and AECO is ($0.31)/MMBtu. Adding this average differential to the rate year AECO forward gas prices results in a rate year average Station 2 price of $4.15/MMBtu for the three months ended July 26, 2011.

Q. How do the changes to the mark-to-market calculation discussed above affect the rate year power costs?

A. Correcting the error and updating the calculation of the Station 2 forward gas prices by using an independent third party forecast basis differentials reduced rate year power costs by $8.0 million.

D. <u>FERC 557 Power Costs Reclassified to A&G</u>

Q. Please explain why some legal costs were reclassified to administrative and general expenses?

A. Rate year power costs include FERC 557, "Other [Power Generation] Expenses" and use the calendar 2010 test year level of costs as an appropriate indicator of the costs to be incurred during the rate year. PSE discovered during a recent review of the FERC 557 costs charged during the test year that $1.5 million of costs charged to order 55700120, "BPA Rate Case – Electric" should have been charged to administrative and general ("<u>A&G</u>") expenses. Accordingly, PSE has reduced rate year power costs by $1.5 million and increased A&G expenses by $1.5 million. Please see the Prefiled Supplemental Direct Testimony of John H. Story, Exhibit No. ___(JHS-11T), for a discussion of this reclassification.

E. Klamath Peakers PPA Transmission Update

Q. Please discuss the transmission contract signed with Portland General Electric Company for the Klamath Peakers PPA.

A. As discussed in Exhibit No. ___(DEM-1CT), PSE has entered into a four-year and two month contract with Iberdrola Renewables for 100 megawatts ("MW") of winter capacity and energy associated with the Klamath Peakers. As further explained in the Prefiled Direct Testimony of Roger Garratt, Exhibit No. ___(RG-1HCT), the Klamath Peakers PPA was contingent upon: (i) Iberdrola Renewables securing firm BPA network transmission on a long-term basis; and (ii) PSE securing transmission from the Klamath Facilities busbar to BPA's John Day substation, each on or before August 15, 2011. Each of these transmission contingencies have been satisfied: (i) Iberdrola Renewables has secured long-term firm BPA network transmission; and (ii) PSE has secured long-term firm PTP transmission service from the Klamath Facilities busbar to John Day under contract with Portland General Electric Company for service commencing January 1, 2012 with a term of five years.

PSE assumed in the prefiled rate year power costs that the transmission would be acquired from BPA at a higher cost than has been secured with Portland General Electric Company. Including the lower Portland General Electric Company transmission rates in the rate year transmission costs results in a $1.1 million rate year power cost decrease.

F. BPA 2012 Rate Case Update

Q. Has BPA finalized its 2012 BPA Rate Case?

A. Yes. BPA finalized its BPA 2012 Rate Case 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.

As discussed in Exhibit No. ___(DEM-1CT), rate year power costs reflected BPA's proposed increase in transmission rates effective October 1, 2011. PSE updated the rate year power costs to reflect BPA's final transmission rates as shown in Table 2 below:

Table 2. 2012 BPA Rate Case Update

	BPA's Current Rates	BPA Preliminary Rates, as Filed on June 13, 2011	BPA Final Rates, as Filed on September 1, 2011
Spinning Reserves ($/MWh)	$8.53	$10.20	$11.20
Supplemental Reserves ($/MWh)	$8.24	$9.63	$9.52
Variable Energy Resource Balancing Services (VERBS) ($/kW-mo.)	$1.29	$1.32	$1.23

Both the Hopkins Ridge Wind Project and the Klondike III Wind Project are within BPA's Balancing Authority ("BA"), and PSE projects that it will place the Lower Snake River Wind Project within BPA's BA. Rate year power costs have decreased $0.5 million from the original filing due to the final rates from the 2012 BPA Rate Case.

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

A. No. PSE did not update the wind integration costs for the Wild Horse Wind Project, which is located within PSE's BA, to reflect the more recent prices discussed above. At this time, PSE projects that any such update would be *de minimis*.

G. Transmission Reassignments

Q. Please describe the updates to the transmission reassignment calculation.

A. As discussed in Exhibit No. ___(DEM-1CT), PSE may have, from time-to-time, surplus PTP transmission because of the shaping of PSE's peak load demand. As a result, PSE has obtained the right to sell excess PTP transmission to eligible customers. The prefiled power costs included a $1.3 million forecast for rate year transmission reassignment revenues based on a calculation of the monthly PTP transmission forecast to be in excess of the transmission needed to meet load.

Recently, PSE requested that BPA convert 100 MW of PSE's long-term firm

Integration of Resources ("IR") transmission to PTP effective November 1, 2011 for a five-year term. PSE requested this conversion because there is no specific resource associated with the transmission, and PTP transmission can be reassigned, whereas IR transmission cannot.

Although the impact to the rate year transmission expense is very minor, the addition of 100 MWs of PTP increases the forecast of the surplus transmission available to be sold during the rate year, which reduced power costs by $0.5 million.

H. Wells Hydroelectric Project Contract Update

Q. What change did PSE make to the forecasted costs under PSE's contract with Douglas PUD for hydroelectric output from the Wells Hydroelectric Project?

A. Douglas PUD has provided a more current Wells Hydroelectric Project preliminary budget for the operating year 2011-2012. As a result of Douglas PUD's lower budget, PSE has reduced rate year power costs by $0.1 million.

I. Other Power Cost Updates

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

A. PSE also updated the following rate year power costs:

(i) PSE updated the costs for the Colstrip 500 kV transmission line to reflect the test year level of costs; and

(ii) PSE updated the cost of acquiring short-term firm transmission to meet forecast peaking capacity needs during the winter months of the rate year to reflect BPA rates developed as part of the 2012 BPA Rate Case.

These updates, and other power cost updates for the rate year, reduced power costs by $0.3 million.

III. CONCLUSION

Q. Does this conclude your supplemental testimony?

A. Yes, it does.