

**EXHIBIT NO. \_\_\_\_ (DEM-7T)**  
**DOCKET NO. UE-070565**  
**2007 PSE PCORC**  
**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-070565**

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

**May 23, 2007**

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**PUGET SOUND ENERGY, INC.**

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

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**PUGET SOUND ENERGY, INC.**

**PREFILED SUPPLEMENTAL DIRECT TESTIMONY  
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**I. INTRODUCTION**

**Q. Are you the same David E. Mills who provided prefiled direct testimony in this Docket on behalf of Puget Sound Energy, Inc. (“PSE” or “the Company”)?**

**A. Yes.**

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

**A. I am updating the projected rate year power costs submitted with my direct testimony for changes that have occurred since the time of the original filing in March 2007.**

**Q. Please summarize your testimony regarding the update of power costs.**

**A. Projected rate year power costs in this supplemental filing are \$1.061 billion, a \$13.8 million increase from the originally filed power costs of \$1.047 billion. This is the net result of certain costs going up and other costs going down from the power costs projected for the March 2007 filing, based on updated information available to PSE. The updated power costs are provided in Exhibit**

Nos. \_\_\_\_ (DEM-8) and Exhibit No. \_\_\_\_ (DEM-9). As discussed in the prefiled supplemental direct testimony of John Story, Exhibit No. \_\_\_\_ (JHS-9T), Mr. Story used these updated power costs, plus other data, to adjust the revenue deficiency for the rate year.

## II. UPDATE TO PROJECTED POWER COSTS

**Q. Have you reconciled the projected power costs filed in March 2007 to the updated projected power costs?**

A. Yes. The table below details the changes to the projected rate year power costs since the March filing.

Rate Year Power Cost Forecast		
	<b>As Filed 3.20.07</b>	<b>\$ 1,047,022</b>
Update Gas Prices and Short Term Contracts to 5.10.07		15,848
Remove Sumas from PSE Resources		(5,022)
Update Snoqualmie Maintenance		(1,882)
Goldendale Production O&M Update		(837)
Remove ORMAT from PSE Resources		110
Coal Cost Updates		3,228
Transmission		1,547
MidC Contract Updates		664
Other		146
	<b>Supplemental 5.23.07</b>	<b>\$ 1,060,822</b>

A more detailed reconciliation between the power cost projections is provided in Exhibit No. \_\_\_\_ (DEM-8).

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2       **Q.     How did the Company update its power costs for the rate year?**

3       A.     PSE updated forward market gas prices and PSE resource assumption inputs to  
4             the AURORA hourly dispatch model. In addition, cost projections outside of the  
5             AURORA model were updated to reflect these and other changes as noted below.

6       **A.     AURORA Model and Gas Price Updates**

7       **Q.     What natural gas prices did the Company use for the rate year in running its**  
8             **AURORA model for this supplemental testimony?**

9       A.     PSE used a three-month average of daily forward market gas prices for the rate  
10            year for each trading day in the three-month period ending May 10, 2007. These  
11            data were input into the AURORA model for each of the months in the rate year.  
12            This is the same methodology as described in my original prefiled direct  
13            testimony except that it uses the more recent three-month period described above.

14           For purposes of comparison, the updated average price at Sumas for the rate year  
15            resulting from use of the updated information is \$7.90/MMBtu, which is \$0.33  
16            higher than the average price included in this proceeding's original filing,  
17            \$7.57/MMBtu. This compares to the average rate year price at Sumas of  
18            \$7.41/MMBtu for PSE's 2006 General Rate Case filing, Docket No. UE-060266  
19            and UG-060267 ("2006 GRC").

1 In addition, projected power costs have been adjusted outside of the AURORA  
2 model to properly reflect fixed-priced natural gas and power contracts in place at  
3 May 10, 2007 for PSE's rate year power portfolio.

4 **Q. Were there changes made to PSE's resources included in the AURORA**  
5 **database for this supplemental filing?**

6 A. Yes, PSE removed two contracts from its rate year resources and updated planned  
7 maintenance to the most recent schedule. Specifically, the below adjustments  
8 were made to PSE's rate year resources:

- 9 (i) Removed the generation and costs associated with the Sumas  
10 Cogeneration power contract. As discussed in the prefiled  
11 supplemental direct testimony of Roger Garratt,  
12 Exhibit No. \_\_\_\_ (RG-20CT), Sumas Energy, Inc. has given notice  
13 to the Company that it will no longer be delivering power under  
14 this contract. Although this contract has been removed from PSE's  
15 resource stack, the Sumas Cogeneration unit remains in the  
16 AURORA database, to be dispatched as a regional resource  
17 whenever economically feasible.
- 18 (ii) Removed the 20-year purchased power agreement between PSE  
19 and OrSumas, LLC for the output of the Northwest Pipeline  
20 recovered heat generation resource at Sumas developed by Ormat  
21 Nevada, Inc. ("Ormat"). At this time, Ormat has requested a time  
22 extension, which would result in a delay until approximately  
23 November 18, 2008 to complete the project. *See*  
24 Exhibit No. \_\_\_\_ (RG-20CT).
- 25 (iii) Removed the Snoqualmie hydro facility's powerhouse 1 outage to  
26 be in synch with the Snoqualmie facility's planned refurbishment  
27 activities required under the FERC-approved construction  
28 schedule. Approximately 4 average megawatts of nearly zero cost  
29 power was added back to the rate year.

1 (iv) Updated to the most recent scheduled maintenance for the  
2 Company's gas fired turbines.

3 The AURORA modeled power costs for the rate year increased \$14.7 million due  
4 to the updates to forecast gas prices and resource and contract data.

5 **Q. Did forecast power costs outside of the AURORA model change as a result of**  
6 **the update to rate year gas prices?**

7 A. Yes. As I noted above, projected power costs have been adjusted outside of the  
8 AURORA model to properly reflect fixed-priced natural gas and power contracts  
9 in place at May 10, 2007 for its rate year power portfolio. The combination of  
10 updating the forecast rate year gas prices and including new short term fixed-  
11 priced natural gas and power contracts at May 10, 2007 decreased rate year power  
12 costs by \$5.7 million. All in, power costs increased \$9.1 million due to the gas  
13 price and resource updates.

14 **B. Coal Price Update**

15 **Q. Please explain the change to projected rate year coal costs.**

16 A. Cost estimates for rate year coal costs were updated to reflect more recent coal  
17 cost information. Colstrip Units 1&2 coal costs were updated to reflect the March  
18 2007 semi-annual contract cost adjustment and the first quarter 2007 royalty  
19 billings. Colstrip Units 1&2 rate year variable commodity coal costs increased an  
20 average of \$0.65/MWh, from \$9.95 to \$10.60, with a resulting \$1.5 million

1 increase in power costs. Colstrip Units 3&4 updated coal costs are now based  
2 upon a May 2007 forecast, compared to the original filing cost support dated June  
3 2006. Colstrip Units 3&4 rate year variable commodity coal costs increased an  
4 average of \$0.41/MWh, from \$8.85 to \$9.25, with a resulting \$1.1 million  
5 increase in power costs. The underlying cost of the power received under the  
6 Northwestern Energy Company's contract increased \$0.2 million due to the  
7 increase in the Colstrip Unit 3&4 costs. These variable cost increases, along with  
8 minor changes to the fixed coal costs, increased projected rate year power costs  
9 \$3.2 million.

10 **C. Mid-C Power Contracts Update**

11 **Q. What caused the increase to the Mid-Columbia ("Mid-C") power contracts?**

12 A. The majority of the increase to PSE's rate year Mid-C power contract costs is due  
13 to a settlement agreement between Public Utility District No. 2 of Grant County,  
14 Washington, and the Yakama tribe which is forecast to increase power costs \$0.5  
15 million. Updating the cost calculation for the Priest Rapids Product to reflect  
16 more recent market prices increased power costs approximately \$0.2 million, for a  
17 total Mid-C cost increase of \$0.7 million.

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1     **D.     Transmission Cost Update**

2     **Q.     Please explain the change to transmission costs for the rate year.**

3     A.     In 2006, PSE increased its Bonneville Power Administration (“BPA”) firm  
4           transmission purchases from the Mid-C to PSE’s system by 650 megawatts. PSE  
5           expected to “remarket” excess transmission during our non-peaking months of  
6           April through October and, in doing so, would reduce transmission costs  
7           approximately \$1.7 million. Both the costs and benefits associated with this BPA  
8           transmission purchase were included in this docket as-filed power costs. In recent  
9           months, however, due to a change in BPA’s transmission business practice, PSE  
10          is anticipating a significant decline in the amount of excess transmission to be  
11          remarketed relative to our earlier assumption. In February 2007, BPA’s  
12          transmission business terminated the practice of system-to-system deliveries of  
13          power for those transactions that were not originally structured as system-to-  
14          system deliveries. Per this change by BPA, PSE must now rely on the firm  
15          transmission from the Mid-C trading hub for power deliveries that were  
16          historically delivered from BPA via system-to-system. The projected rate year  
17          power costs have increased \$1.3 million due to this business practice change.  
18          Transmission costs for the rate year have increased approximately \$1.5 million  
19          after considering other minor transmission cost changes.

1 **E. Production O&M Cost Update**

2 **Q. How has PSE updated its forecast of Production Operation and Maintenance**  
3 **costs in this supplemental filing?**

4 A. To update its rate year power costs, PSE has made the following adjustments to its  
5 originally filed production operation and maintenance (“O&M”) costs:

6 i) Updated the O&M costs for the Goldendale Generating Station  
7 resource to reflect more recent information, as discussed in the  
8 prefiled supplemental direct testimony of Roger Garratt,  
9 Exhibit No. \_\_\_\_ (RG-20CT), for a total cost decrease of  
10 \$0.8 million; and

11 ii) Updated the proforma Fredonia 3 & 4 lease costs to reflect the  
12 lease costs expected in the rate year for a cost increase of \$0.2  
13 million.

14 In total, PSE’s rate year production O&M costs are \$92.9 million, a decrease of  
15 \$0.6 million from the originally filed production O&M costs.

16 **III. PROJECTED POWER COSTS WITHOUT**  
17 **THE GOLDENDALE GENERATING STATION**

18 **Q. How would rate year projected power costs for this case change if the**  
19 **Goldendale Generating Station were not included as a resource?**

20 A. PSE ran the AURORA model with the same assumptions as for the rate year  
21 power costs presented in this supplemental filing, except removed the Goldendale  
22 Generating Station. The model showed that, with the forecast generation from

1 Goldendale Generating Station, PSE would need to purchase less market power,  
2 or would sell more excess power in the market, than would have been the case  
3 without Goldendale. Even so, for the rate year, the inclusion of Goldendale  
4 increases power costs by \$10.9 million, with \$8.5 million of this increase due to  
5 incremental production operations and maintenance costs. This compares to the  
6 as-filed information that showed Goldendale increased power costs \$10.8 million  
7 with \$9.3 million of production operations and maintenance costs. *See Exhibit*  
8 *No. \_\_\_\_ (DEM-10).*

9 **IV. CONCLUSION**

10 **Q. Does this conclude your testimony?**

11 **A.** Yes, it does.

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