EXHIBIT NO. ___(DEM-5CT)
DOCKET NO. UE-130617
2013 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-130617**

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

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VERSION

JULY 2, 2013

PUGET SOUND ENERGY, INC.

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

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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 this docket on behalf of Puget Sound Energy, Inc. ("PSE")?

A. Yes, I filed prefiled direct testimony, Exhibit No. ___(DEM-1CT), and three supporting exhibits, Exhibit No. ___(DEM-2) through Exhibit No. ___(DEM-4C).

Q. What is the nature of your prefiled supplemental direct testimony in this proceeding?

A. This prefiled supplemental direct testimony updates PSE's requested rate relief and 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 original filing on April 25, 2013. This prefiled supplemental direct testimony updates the following issues relevant to both this power cost only rate case ("PCORC") and power costs for this proceeding's rate year November 1, 2013 through October 31, 2014 (the "rate year"):

(i) an update to PSE's requested rate relief;

(ii) an update to PSE's projected rate year power costs for this proceeding, including changes in the underlying resources and resource assumptions available to PSE to meet customer demand;

(iii) an update on PSE's plan to file an accounting petition to defer costs associated with its Cedar Hills Regional Landfill facility ("Cedar Hills biogas"); and

(iv) an introduction to the other witnesses providing prefiled supplemental direct testimony.

II. UPDATE TO REQUESTED RATE RELIEF

Q. What rate relief is PSE requesting in this supplemental filing?

A. This filing reflects an increase in the requested rate recovery from that presented in PSE's prefiled direct case and supports PSE's proposal to increase rates for electric customers by $491,934, an average 0.02 percent increase from the electric power cost adjustment mechanism ("PCA") rates set in PSE's 2011 general rate case, Docket Nos. UE-111048 and UG-111049 (the "2011 GRC"), that became effective on May 14, 2012. For purposes of comparison, PSE's initial request in this proceeding was to lower rates for electric customers by $618,683, or an average 0.03 percent decrease from current rates. Please see Exhibit No. ___(KJB-8T) for a discussion of the revenue requirement calculation.

III. UPDATE TO PROJECTED POWER COSTS

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

A. Projected rate year net power costs in this supplemental filing are $742.8 million—a $4.2 million increase from the originally filed power costs of $738.6 million and a $67.3 million *decrease* from amounts set in current rates. Although PSE's power cost projections for the rate year have increased from those included in the prefiled direct testimony, they still remain significantly lower—*eight* percent lower—than the power cost projections currently in PSE's rates.

Please see Exhibit No. ___(DEM-6) and Exhibit No. ___(DEM-7C) for the updated rate year power costs. As discussed in the Prefiled Supplemental Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-8T), PSE has updated the revenue requirement to reflect these updated power costs.

Q. Has PSE reconciled the projected power costs filed on April 25, 2013, to the updated projected power costs?

A. Yes. Please see Exhibit No. ___(DEM-6) and Exhibit No. ___(DEM-7C) 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 April 25, 2013.

Table 1. 2013 PCORC Rate Year Power Cost Forecast

2013 PCORC Power Costs Projections - AURORA + Not in Models
Rate Year November 2013 through October 2014
(dollars are in thousands)

	Price Date	**AURORA**	**Not in Models**	**Total**	**Load**
As-Filed Power Costs – 3.5.13 prices	3.5.13	$491,125	$247,504	$738,629	22,890,882
Gas Price & Gas for Power Hedges Update		$7,041	($3,816)	$3,225	
Cedar Hills biogas mark-to-market			($232)	($232)	
Power Hedges Update		($443)		($443)	
Electron PPA lowered generation & moved to AURORA		$1,327	($1,919)	($592)	
Contract Updates for Koma Kulshan and WNP-3		$273		$273	
Schedule 91 Contract Update		($217)		($217)	
Colstrip Reclamation		$440		$440	
Gas-Fired Turbine assumptions		$303		$303	
Reduction in LGIA Deposit due to Sale of LSR Phase 2			$744	$744	
BPA 2014 Rate Case Stlmt Agmt + 30/60 VERBS Schedule Option			($1,195)	($1,195)	
Gas Transport - mostly Westcoast Pipeline Rate Increase			$2,059	$2,059	
Mid-C Contract costs			$16	$16	
Other		($137)	($73	($210)	
Total Change		$8,587	($4,416)	$4,171	
Supplemental Power Costs – 6.3.13 prices	6.3.13	$499,712	$243,087	$742,800	22,890,882

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

A. As shown in Table 1 above, projected power costs changed as PSE updated forward market gas prices and PSE resource 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. PSE made these updates to rate year power costs to reflect current changes in power cost assumptions and inputs from those proposed in my prefiled direct testimony. This update is intended to provide current information in a timely manner in accordance with the final order in PSE's 2011 GRC, in which the Commission stated as follows:

> The Commission consistently strives to reflect the most recent operating and market conditions when setting power costs. In tandem with that aim, is the Company's responsibility to provide an informed record in a timely manner.[1]

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 June 3, 2013[2] and the short-term rate year power hedges as of the same date;

(ii) rate year contract prices and/or volumes for the following purchase power contracts:

(a) the proposed power purchase agreement with Electron Hydro LLC ("Electron Hydro") related to the Electron Hydroelectric Project (the "Electron PPA"),

(b) the WNP-3 BPA Exchange agreement with Bonneville Power Administration (the "WNP-3 Exchange Agreement"),

(c) the power purchase agreement with Koma Kulshan Associates related to the Koma Kulshan hydro project (the "Koma Kulshan PPA"), and

(d) a single contract under PSE's Schedule 91 tariff;

(iii) Colstrip mine reclamation cost updates per Western Energy Company; and

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1 *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-111048 and UG-111049, Order 08 at ¶ 262 (May 7, 2012).

2 Gas Price cutoff date included in the Prefiled Direct Filing was March 5, 2013.

(iv) more current operating characteristics and assumptions for PSE's gas generation resources.

As shown in Exhibit No. ___(DEM-7C), the AURORA modeled power costs for the rate year increased $8.6 million from the power costs filed on April 25, 2013, 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) the mark-to-market calculation for gas for power contracts in place at June 3, 2013;

(ii) moving the Electron PPA impact to the AURORA model;

(iii) updated forecast transmission costs:

(a) to include rate updates from Bonneville Power Administration's ("BPA") 2014 Wholesale Power and Transmission Rate Adjustment Proceeding (the "BPA 2014 Rate Case") and to reflect PSE's scheduling election for BPA's Variable Energy Resource Balancing Service ("VERBS"), and

(b) to reduce PSE's Large Generator Interconnection Agreement ("LGIA") deposit for the pending sale of Phase II of PSE's Lower Snake River Wind Facility ("LSR Phase 2") and the interest calculated to be received from BPA;

(iv) updated Westcoast Energy, Inc. ("Westcoast") pipeline rates;

(v) updated rate year budget information for PSE's Mid-Columbia ("Mid-C") contracts with the Public Utility District No. 1 of Douglas County, Washington ("Douglas PUD") for the output from the Wells

Hydroelectric Project, with the Chelan Public Utility District ("Chelan PUD") for the output from the Rocky Reach and Rock Island Hydroelectric Projects and with the Public Utility District No. 2 of Grant County, Washington ("Grant PUD") for output from the Wanapum and Priest Rapids Hydroelectric Projects; and

(vi) other power cost updates.

As shown in Exhibit No. ___(DEM-7C), these changes *decreased* costs outside of the AURORA model – the Not-in-Models costs – by $4.4 million.

A. <u>Natural Gas Price Update</u>

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 June 3, 2013. PSE input these data and the rate year fixed-price short-term power contracts in place at June 3, 2013 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).

For purposes of comparison, the updated average price at Sumas for the rate year is $4.21/MMBtu. This updated average price is $0.18/MMBtu higher than the average price of $4.03/MMBtu used in PSE's original filing on April 25, 2013, which 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 March 5, 2013. The

AURORA modeled rate year power cost increased by $6.6 million as a result of this update.

Q. Did updating the rate year natural gas prices affect the mark-to-market calculation in Not in Models?

A. Yes. PSE also updated the projected power costs outside of the AURORA model to reflect fixed-price natural gas contracts and any premiums and discounts associated with index power and gas for power contracts that are in place at June 3, 2013. The Not in Models mark-to-market adjustment represents (i) the difference between the fixed price of the short-term gas for power contracts and forward gas prices, and (ii) the benefit of firm gas transportation contracts. The updated Not in Models mark-to-market adjustment decreased costs for the rate year by $4.0 million, which increased the total mark-to-market benefit from a credit of $9.1 million (as included in the direct filing on April 25, 2013) to a credit of $13.1 million (as included in this supplemental direct filing on July 2, 2013).

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 $2.6 million to reflect the three-month average forward gas prices at June 3, 2013. This routine update includes updates to

(i) the AURORA model for the more recent gas prices and fixed-price short-term rate year power contracts in place at the pricing date, and

(ii) the Not-in-Models costs to reflect the updated forecast gas prices and the more current fixed-price short-term natural gas for power contracts and index-based power and gas for power contracts.

B. Contract Updates

1. Electron PPA

Q. Please discuss the rate year contract update included in the AURORA model related to the Electron PPA.

A. My prefiled direct testimony explained PSE's intent to move the Electron PPA from an adjustment in Not in Models to a resource in the AURORA model during the course of this proceeding. Accordingly, the AURORA model now reflects the rate year forecast generation, costs and planned maintenance for the Electron PPA. The rate year Electron PPA generation forecast uses the 70-year historical westside streamflow records (1929 through 1998) to be consistent with PSE's Mid-C generation forecast methodology. PSE has limited the Electron PPA forecast generation to consider the Electron Project's current and expected capacity limitations and reflects Electron Hydro's planned maintenance. PSE has removed the adjustment previously included in the Not in Models for the Electron PPA. The effect of including the Electron PPA in the AURORA model increased power costs \$1.3 million, yet removing the Electron PPA from the Not in Models calculation decreased rate year power costs \$1.9 million, for a net decrease to rate year power costs of \$0.6 million.

2. WNP-3 Exchange Agreement

Q. Please discuss the rate year contract update included in the AURORA model related to the WNP-3 Exchange Agreement.

A. PSE has also updated the AURORA model contract rates and volumes to reflect the draft annual update to the WNP-3 Exchange Agreement, which increased the volumes available under this contract and decreased the cost per megawatt hour ("MWh"). Because the final update for this contract has historically not changed from the draft, PSE is updating power costs at this time and will also provide the final updated contract when received in August 2013. Rate year power costs increased $0.2 million for this contract update.

3. Koma Kulshan PPA and Three Bar G PPA

Q. Please discuss the rate year contract update included in the AURORA model related to the Koma Kulshan PPA and the Three Bar G PPA.

A. PSE has updated the contract rate for the Koma Kulshan PPA to reflect more current expected contract costs, and AURORA also reflects an amendment of the Three Bar G contract under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production" that will reduce the amount of Schedule 91 contract power forecast for the rate year. Rate year power costs decreased $0.1 million for these contracts update.

In total, the rate year power costs decreased $0.5 million due to contract updates.

C. Colstrip Mine Reclamation Costs

Q. Please explain the update to the AURORA inputs for the Colstrip units reclamation costs.

A. Western Energy Company prepares an annual study of the reclamation costs associated with coal mining, and PSE updated the Colstrip final mine reclamation costs to the 2013 costs in the coal cost workpapers. Federal and Montana laws and mining permits require the reclamation of mines to ensure a post-mining topography similar to the original ground contours and drainage patterns. The buyers pay these costs (as part of the current year's cost of coal) to Western Energy Company (the mine operator) under the Coal Supply Agreements to fund remaining mine reclamation costs after conclusion of mining. This update increased rate year power costs by approximately $0.4 million.

D. Gas-Fired Turbine Assumptions

Q. Please explain the changes to the operating characteristics for PSE's gas-fired turbines which were input to the AURORA model.

A. The AURORA model makes commitment and dispatch decisions on an hourly basis utilizing the resource and operating characteristics of the thermal generators and the costs of fuel. These characteristics include items such as operating capacity, base load heat rates, minimum up times and minimum down times and represent PSE's operating information used to dispatch and operate PSE's combustion turbine fleet. PSE's asset management group, in concert with PSE plant managers, maintain and review actual plant operating statistics to ensure PSE's gas-fired combustion turbines are operating efficiently and reliably given the operating and maintenance constraints of the individual turbines. As the combustion turbines age and receive normal and major maintenance, the thermal operating characteristics of the combustion turbines will vary. PSE's thermal operations group provides updates to the thermal operating characteristics on an ongoing basis such that PSE is using the most current information to make plant dispatch decisions. At this time, the only thermal operating characteristic for PSE's combustion turbines that requires updating is the heat rate of the Sumas Generating Station.

Q. Were there other changes made to the AURORA modeling of PSE's resources?

A. Yes. PSE updated the AURORA model inputs to reflect more recent planned maintenance schedules and to reflect the semi-annual fuel factor change of Northwest Pipeline, GP ("Northwest Pipeline").

Q. What is Northwest Pipeline's semi-annual fuel factor change?

A. Northwest Pipeline has filed a semi-annual fuel filing for the variable cost of fuel and received approval to increase its tariffs effective April 1, 2013. Accordingly, PSE increased the variable gas adders included in the AURORA model for PSE's gas-fired generators to reflect the change.

Q. What is the impact to rate year power costs for these operating assumption changes?

A. Rate year power costs have increased $0.3 million due to the changes to PSE's resources noted above.

E. <u>BPA Transmission Costs</u>

Q. Are there changes to the rate year BPA transmission rates that are presented in Not in Models?

A. Yes. PSE has updated rate year transmission rates to represent more recent information from BPA's current rate proceeding. As discussed in my prefiled direct testimony, BPA is conducting a combined power and transmission rate proceeding to set new transmission and ancillary services rates for BPA's fiscal years 2014-2015 (effective October 1, 2013, through September 30, 2015). PSE proposed to update power costs during this proceeding to reflect the final BPA 2014 Rate Case rates. On May 15, 2013, BPA posted and filed a Record of Decision on Generation Inputs and Transmission Ancillary Control Area Services Rate Settlement Agreement ("Settlement Agreement"),[3] finalizing a subset of rate issues. The rates finalized under the Settlement Agreement that affect PSE's rate year power costs include (i) the VERBS rate for 30/60 committed scheduling and (ii) the Regulation and Frequency Response Service and Operating Reserve (Spinning & Supplemental) rates. Table 2 below presents a comparison of these

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3 The Settlement Agreement may be accessed at: http://www.bpa.gov/Finance/RateCases/BP-14RateAdjustmentProceeding/Pages/default.aspx.

rates from those included in the prefiled direct testimony and from those currently included in rates.

Table 2. BPA 2014 Rate Case Proposed and Final Rate Changes

Service	Volumetric Measure	Current Rate	Proposed Rates per Nov12 Filing[1]	Final Rates per Settlement Agreement[2]	Proposed or Final Change from Current
Integration of Resources	$/kW/mo	1.498	1.794	N/A	19.8%
Point to Point	$/kW/mo	1.298	1.544	N/A	18.6%
Scheduling, System Control & Dispatch	$/kW/mo	0.203	0.254	N/A	25.1%
Operating Reserve - Spinning Reserve	$/MWh	11.20	10.86	10.86	(3.0%)
Operating Reserve – Supplemental Reserve	$/MWh	9.52	9.95	9.95	4.5%
Variable Energy Resource Balancing Service (VERBS)					
		Uncommitted		**Committed 30/60**	
Regulating Reserve	$/kW/mo	0.08	0.08	0.08	0.0%
Following Reserve	$/kW/mo	0.37	0.36	0.36	(2.7%)
Imbalance Reserve	$/kW/mo	0.78	0.95	0.80	2.6%
Total	$/kW/mo	1.23	1.39	1.20	(2.4%)
WNP, based on FPT-14.3	$/MW/mo	880.00	1,060.00	N/A	20.5%
Southern Intertie	$/kW/mo	1.293	1.152	N/A	(10.9%)

1: BPA's November 2012 proposed rates were included in PSE's rate year power costs presented in the April 25, 2013 prefiled direct case.
2: "N/A" means the Settlement Agreement did not finalize the rate for this service and the rates are still subject to BPA's final Record of Decision (expected on or about July 22, 2013).

Q. What are the changes to the costs of transmission for the rate year due to BPA's 2014 Rate Case updates?

A. As the above Table 2 indicates, the final Operating Reserves rates to be effective October 1, 2013 did not change, and, hence, there was no impact to rate year power costs. The VERBS rates, however, decreased from a total of $1.39 per kilowatt per month (kW/mo) to $1.20 per kW/mo because, as discussed in the prefiled direct testimony of Mr. Mathew D. Rarity, Exhibit No. ___(MDR-1CT), PSE submitted its VERBS scheduling election to BPA, electing to schedule the Hopkins Ridge Wind Project ("Hopkins Ridge") and Phase 1 of the Lower Snake River Wind Project ("LSR Phase 1") at the "30/60 committed scheduling" level, which requires hourly wind scheduling equivalent to, or better than, a 30-minute persistence forecast. The impact of these final rates on PSE's rate year power costs, which includes a minor increase in the expected generation imbalance costs due to higher forecast Mid-C prices, is a *reduction* of approximately $1.2 million, as shown in Tables 3 and 4 below.

Table 3. Prefiled Rate Year Costs to Integrate PSE Wind Resources

Wind Project & Capacity	Capacity Factor	Rate Year Generation	Balancing Authority	Total Costs	$/MWh
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Total Wind Integration Costs				$12,746,642	

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Table 4. Rate Year Costs to Integrate PSE Wind Resources, Updated For PSE's VERBS 30/60 Committed Scheduling Election and BPA's Settlement Agreement posted May 15, 2013

Wind Project & Capacity	Capacity Factor	Rate Year Generation	Balancing Authority	Total Costs	$/MWh
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Total Wind Integration Costs				$11,585,580	
Decrease in Wind Integration Costs				**($1,161,062)**	

Q. Are there other changes to the costs of transmission for the rate year?

A. Yes. In June 2013, Portland General Electric ("PGE") agreed to buy PSE's interests in the development assets required for the construction and operation of LSR Phase 2. Please see the Prefiled Supplemental Direct Testimony of Mr. Michael Mullally, Exhibit No. ___(MM-8CT), for a discussion of this transaction. As part of this transaction, PGE assumed 267 megawatts ("MW") of PSE's Large Generator Interconnection Agreement ("LGIA") deposit with BPA at a pro-rata share cost of approximately $20.5 million. As explained in the Prefiled Supplemental Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-8T), the reduction in PSE's regulatory asset for the LGIA deposit results in less interest to be received from BPA to offset rate year transmission costs, thus increasing power costs. Accordingly, rate year power costs have

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increased $0.7 million due to the change in the LGIA deposit. In total, rate year transmission costs have decreased $0.4 million.

Q. Does PSE plan to update transmission costs later in this proceeding?

A. Yes. BPA's 2014 Rate Case is still proceeding, and PSE expects that BPA will issue a Final Record of Decision in that proceeding on or about July 22, 2013.

Q. Did PSE update wind integration costs within PSE's balancing authority area 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 balancing authority area.

F. <u>Westcoast Pipeline Rates</u>

Q. Please explain why the costs for PSE's Westcoast pipeline capacity have increased.

A. PSE's power portfolio holds contracts for approximately 106,000 MMBtu per day of firm natural gas pipeline transportation capacity on the Westcoast pipeline system for the ability to move natural gas from the Station 2 hub to the Sumas hub. To recognize a shortfall in expected revenues to recover its costs, Westcoast has received approval to increase its transportation service tolls effective July 1, 2013, effectively increasing PSE's firm transportation service rate on the Westcoast system by 11.5 percent. The firm natural gas transportation costs increased $2.1 million for the rate year as a result of this rate increase.

G. Mid-C Contracts

Q. What changes did PSE make to the forecasted costs under PSE's Mid-C contracts?

A. Douglas PUD has provided a more current Wells Hydroelectric Project preliminary budget for the operating year 2013-2014. As a result of Douglas PUD's lower budget, PSE has reduced rate year power costs by $0.2 million.

Chelan PUD has provided the final transmission charges for the period July 2013 through June 2014 for the hydroelectric output from the Rock Island 1&2 and Rocky Reach Hydroelectric Projects, increasing rate year costs $0.4 million.

Grant PUD's estimated contract costs for the Priest Rapids Hydroelectric Project have decreased $0.2 million due to the increased power cost forecast that increases the expected revenues under the contract.

The net effect of the Mid-C contract cost updates was a zero change to rate year costs.

H. Other Power Cost Updates

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

A. PSE's other updates to power costs include updates for transmission reassignment revenues for the most recent twelve months in accordance with the calculation set in the 2011 GRC as well as other power cost items that update automatically in the MS Excel files whenever prices are updated or a new AURORA model run download is included in the files. These other power cost updates reduced power costs by $0.2 million.

IV. UPDATE TO BIOGAS ACCOUNTING PETITION

Q. Please provide an update on the rate year power costs for PSE's costs associated with its Cedar Hills Regional Landfill facility ("Cedar Hills biogas").

A. My prefiled testimony noted that PSE included a placeholder in the rate year power costs for the mark-to-market adjustment for PSE's contract with Bio Energy (Washington), LLC for the purchase of the pipeline quality gas produced by the Cedar Hills Regional Landfill facility until the outcome of PSE's accounting petition to defer these costs is known. PSE is planning to file this accounting petition in early July, and as the outcome of this petition is yet unknown, the mark-to-market costs of the Cedar Hills biogas is included in the rate year power costs in the mark-to-market adjustment and totals $2.0 million. Rate year power costs for this contract have decreased $0.2 million from the costs included in the original rate year power costs due to the increased rate year gas prices.

V. PSE WITNESSES FILING SUPPLEMENTAL DIRECT TESTIMONY

Q. Would you please describe briefly the PSE witnesses providing supplemental testimony in this case and the topics presented by each witness?

A. Yes. The following witnesses also present supplemental direct testimony on PSE's behalf:

Ms. Katherine Barnard, Director of Revenue Requirements and Regulatory Compliance for PSE, presents an update to the electric results of operations and revenue requirement and power cost baseline rate.

Mr. Michael Mullally, Senior Energy Resource Planning & Acquisition Analyst for PSE, presents (i) a discussion of the sale of the PSE's interests in the development assets required for the construction and operation of LSR Phase 2 to PGE and (ii) an update regarding the Electron PPA.

Mr. Paul K. Wetherbee, PSE Director of Hydroelectric and Wind Resources Assets Management for PSE, presents an update regarding the sale of the Electron Project to Electron Hydro.

VI. CONCLUSION

Q. Does this conclude your supplemental testimony?

A. Yes, it does.