EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-13____
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-13____**

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

REDACTED
VERSION

APRIL 25, 2013

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

I. INTRODUCTION

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

A. My name is David E. Mills. My business address is 10885 NE Fourth Street, P.O. Box 97034, Bellevue, WA 98009-9734. I am the Vice President, Energy Supply Operations for Puget Sound Energy, Inc. ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(DEM-2).

Q. What are your duties as Vice President, Energy Supply Operations at PSE?

A. As Vice President, Energy Supply Operations, my responsibilities include oversight of PSE's Power and Gas Supply Operations, Load Serving Operations, Transmission Contracts, and Energy Supply Operations Policy, Planning & Compliance groups. My responsibilities include management of PSE's short- and medium-term wholesale power and natural gas portfolios (up to three years) and involvement with long-term hedging requirements. My responsibilities also include developing strategies to address risks related to PSE's electric and gas portfolios as well as the continuous operation that monitors, operates, and controls transmission switching, generation dispatch, control area load balancing, and real-time transmission scheduling for PSE and its customers. I was responsible for the oversight of the development of the 2011 Integrated Resource Plan (the "2011 IRP") which has been provided as the Second Exhibit to the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-3).

Q. What has prompted PSE to file a power cost only rate case (the "PCORC") at this time?

A. PSE continues to have a need to acquire additional generation resources to serve its electric customers and has been pursuing various opportunities to fill this need. The acquisition of the Ferndale Generating Station was a key factor enabling PSE to meet this demand. In addition, PSE is investing in existing resources to meet customers' needs as is evident from the new 30-megawatt powerhouse at the Baker River Hydroelectric Project (the "Baker Project") and the redevelopment and upgrades of the Snoqualmie Falls Hydroelectric Project (the "Snoqualmie Falls Project"). These new and upgraded resources will provide benefits to customers for many years to come and have prompted the need to seek recovery of the capital and operating costs of the production plants.

[redacted]

[redacted]

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

A. This prefiled direct testimony addresses the following issues relevant to both the PCORC and power costs for this proceeding's rate year November 2013 through October 2014 (the "rate year"):

(i) PSE's requested rate relief;

(ii) PSE's power portfolio[1] risks;

(iii) PSE's structures and policies to manage these risks, including, but not limited to, hedging strategies;

(iv) the impact of the Bonneville Power Administration's ("BPA") current rate proceeding and renewal of BPA transmission contracts;

(v) PSE's plan to meet peak load requirements;

(vi) PSE's projected rate year power costs for this proceeding, including new resources and changes in resources available to PSE to meet customer demand;

(vii) a comparison of PSE's projected rate year power costs for this proceeding to those currently in rates; and

(viii) an introduction to the other witnesses in the case and the topics they will address in their prefiled direct testimony.

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[1] The electric "portfolio" consists of resources available to PSE to serve its customers. The electric portfolio includes generation facilities, purchased power and transmission capacity. Please see Appendix D of the 2011 IRP, a copy of which is provided as Exhibit No. ___(RG-3), for a discussion of PSE's electric resources.

PSE's power cost projections for the rate year (November 1, 2013, through October 31, 2014) are significantly lower—$71.5 million, or *eight* percent lower—than power cost projections currently in PSE's rates. There are a number of reasons for this decline, but the key factors for the decline include (i) lower priced power and gas for power long- and short-term contracts; (ii) the return of generation from the renovated Snoqualmie Falls Project; and (iii) a reduction of customer load as a result of Jefferson County customers transitioning to Jefferson County Public Utility District No. 1 ("Jefferson PUD") effective April 1, 2013.

II. REQUESTED RATE CHANGE

Q. What level of rate change is PSE requesting in this case?

A. PSE is proposing to *lower* rates for electric customers by ($618,683), an average 0.03 percent decrease 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. Please see Exhibit No. ___(KJB-6).

Q. Please explain why PSE is proposing a decrease in this proceeding.

A. PSE's current electric rates include all production-related costs to provide the power needed to serve its electric customers for the 2011 GRC rate year: May 1, 2012 through April 30, 2013. Since those costs were determined, changes have occurred or will occur with respect to PSE's electric portfolio that, in total, are projected to decrease PSE's revenue requirement during the proposed rate year for this case: November 1, 2013 through October 31, 2014. These changes are discussed in my testimony below and in the testimonies of several witnesses I will introduce in my testimony.

Q. Is PSE requesting any other determination in this proceeding?

A. Yes. PSE seeks a prudence[2] determination in this proceeding with respect to:

(i) the acquisition of the Ferndale Generating Station and the costs associated with this project;

(ii) [redacted];

(iii) the renovation and upgrades at Snoqualmie Falls Project to implement the Federal Energy Regulatory Commission ("FERC") license;

(iv) the addition of a fourth generator unit and a floating surface collector at the Baker Project to implement the FERC license; and

(v) PSE's transmission contracts with BPA.

PSE is also requesting approval to recover [redacted] the amounts deferred under the Revised Code of Washington 80.80.060 for the Snoqualmie and Baker Projects and the Ferndale Generating Station. Additionally, PSE is requesting the Commission determine the incremental electricity from the Snoqualmie and Baker Projects qualify as renewable resources under the Energy Independence Act.

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2 For a discussion of the prudence standard, please see the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1CT).

Finally, PSE also requests a waiver of the requirement that it file a general rate case within three months of the effective date of a rate change resulting from this PCORC, as required by the PCA Settlement approved by the Commission in Docket Nos. UE-011570 and UG-011571. Please see the Second Exhibit to the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-3), for a copy of the PCA Settlement.

On March 22, 2013, PSE, Commission Staff, and the Northwest Energy Coalition (the "Settling Parties") filed a Multiparty Settlement Agreement ("Multiparty Settlement") to settle several PSE rate proceedings, Docket No. UE-121373 (the Coal Transition PPA proceeding), Docket Nos. UE-121697 & UG-121705 (the decoupling proceedings) and Docket No. UE-130137 & UG-130138 (the expedited rate filing proceedings). In Section IV.C. of the Resolution of Issues of the Multiparty Settlement, PSE has agreed (except as otherwise provided in Section IV.C.) to file a general rate case no earlier than April 1, 2015, and no later than April 1, 2016, unless otherwise agreed to by the parties in PSE's 2011 GRC.

Section IV.C. of the Resolution of Issues of the Multiparty Settlement notes that the Settling Parties agree that this requirement to file a general rate case within three months of an effective date of a rate change resulting from this PCORC should be waived by the Commission.

III. VOLATILITY AND RISK IN PSE'S ELECTRIC RESOURCE PORTFOLIO

Q. Why is energy risk management a concern to PSE?

A. A key responsibility of PSE is to provide safe and reliable electric service at a reasonable cost to its customers. To ensure PSE customers receive the power they need, PSE manages a complex power portfolio during every hour of every day, relying on the region's power markets to supply additional electricity to balance customer demand with PSE's available power resources. PSE's power resource portfolio is subject to significant volatility and risk that ultimately have a substantial impact on energy costs.

Q. What drives volatility and risk in the power portfolio?

A. PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. Although there are many complex variables embedded in the portfolio, the major drivers of power cost volatility are:

(i) streamflow variation affecting the supply of hydroelectric generation;

(ii) weather and economic uncertainty affecting power usage;

(iii) variations in market conditions resulting in changes to wholesale gas and electric prices;

(iv) risk of forced generation outages;

(v) variability of wind generation; and

(vi) transmission and transportation constraints.

All of these have an impact on load and resources, which PSE may balance with wholesale market purchases and sales.

Q. Please describe the volatility related to variations in streamflow affecting hydroelectric supply.

A. There are four main factors that can affect streamflow:

(i) below average runoffs;

(ii) average runoffs;

(iii) above average runoffs; and

(iv) the timing or shape of the runoff.

During an average streamflow year, nearly 20 percent of PSE’s electric energy production is from hydroelectric resources. During poor streamflow conditions, PSE may need to purchase supplemental power or run gas-fired generating units to serve its customer load, both of which are more costly than hydro resources. During favorable streamflow conditions, PSE may need to purchase less or sell surplus power in the wholesale power markets to balance its supply portfolio which can greatly affect PSE’s power costs. The regional market price of power is heavily influenced by hydro conditions each year. Typically, market power prices tend to be higher during a “dry” year and lower during a “wet” year. In all of the runoff conditions, the timing or shape of the runoff also influences the market price of power.

Q. Please describe the volatility that is related to load and temperature uncertainty.

A. The level of PSE's electric retail load is correlated with temperature. The correlation of load and temperature is especially apparent considering how PSE's load increases as temperatures decline during the winter heating season. In light of the significant electric heating load in PSE's service territory, PSE's costs related to load/temperature uncertainty can be significant.

Although still a winter peaking utility, PSE also experiences summer peaking demand. This is due in part to increasing use of electric air conditioning and presents another example of electric load volatility attributable to temperature.

Q. Please describe the risks related to market price volatility.

A. The previously discussed volume-related risks directly affect PSE's exposure to market prices. As resource generation and load demand change, PSE may be subject to significant price-related risk associated with the expected volume of purchases and sales of power in the wholesale markets and the need to purchase or sell natural gas in connection with the operation of its gas-fueled generating units.

Q. Please describe the volatility related to forced outages.

A. As shown in Table 1 below, for the rate year, PSE will rely on approximately 2,623 megawatts ("MW") of thermal generating units to help meet its customer loads.

Table 1. PSE's Thermal Generation Units

	Capacity (MW)
Coal	658
Goldendale	262
Mint Farm	289
Ferndale	273
Frederickson 1/Atlantic Power	134
Encogen	162
Sumas	132
NUGs	100
Simple Cycle CTs	613
Total MWs	**2,623**

The capacities shown above represent the current operational capacities at International Standard Organization conditions. These units include:

(i) 658 MW of large, base-load coal generation with low variable fuel costs;

(ii) 1,353 MW of gas-fired, combined-cycle combustion turbine with moderate heat rate conversions; and

(iii) 613 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generation.

Equipment failure, fire, electrical disturbances, transmission outages or other such events typically cause forced outages. Forced outages at any of these units can expose PSE to significant price volatility in its power supply portfolio.

Q. Please explain the variability of wind generation.

A. PSE's power portfolio benefits from approximately 822 MW of wind generation. Wind resources, however, have significant variability as evidenced by comparing short-term wind generation forecasts to actual generation. PSE must manage this short-term generation variability by: (1) purchasing wind integration services from BPA; (2) reshaping contracted Mid-Columbia ("Mid-C") hydro generation; and (3) utilizing other generating assets within its system to accommodate the variable output of the wind facilities. Such reshaping takes place on a day-ahead and real-time basis and affects PSE's power costs as PSE must adjust other resources' generation levels on a day-ahead and real-time basis to accommodate forecast and actual fluctuations in wind generation. Table 2 below provides a summary of PSE's expected rate year wind generation and capacity:

Table 2. PSE's Wind Generation Capacity, Generation and Capacity Factor

	Capacity (MW)	# Turbines	Rate Year Generation (MWhs)	Capacity Factor
Hopkins Ridge	156.6	87	[redacted]	[redacted]
Wild Horse	228.6	127	[redacted]	[redacted]
Wild Horse Expansion	44.0	22	[redacted]	[redacted]
LSR Phase 1	342.7	149	[redacted]	[redacted]
Klondike III PPA	50.0	N/A	[redacted]	[redacted]
Total	**821.9**	**385**	2,195,964	

Wind integration costs are discussed more fully in the Prefiled Direct Testimony of Mr. Matt Rarity, Exhibit No. ___(MDR-1CT).

Q. What risks are related to transmission and transportation constraints?

A. PSE is exposed to transmission and natural gas transportation risks, such as pipeline outages, curtailments of transmission due to de-ratings,[3] and forced outages. For example, if power cannot be wheeled[4] from the Mid-C trading hub to PSE's system, PSE would be forced to meet load by dispatching other resources or making market purchases from unconstrained points that may be higher cost.

Q. Are PSE's power costs subject to other risks?

A. Yes. Examples of other risks to PSE's power costs include, but are not limited to counterparty credit risk and execution risk. Counterparty credit risk refers to the risk of default by PSE's counterparties on contractual obligations. Execution risk refers to the ability to execute wholesale market transactions and includes, for example, counterparty credit requirements, PSE's credit standing, and contractual requirements.

IV. PSE'S MANAGEMENT OF POWER COST RISK

Q. How does PSE manage the volatility of power costs?

A. PSE has had organizational structures, policies and overarching strategies in place for many years to provide oversight and control of PSE's energy portfolio

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3 De-rating refers to a decrease in the rated electric capability of an electric transmission line.

4 Wheeling refers to the use of the transmission facilities of one power system to transmit power of and for another system. This term is often used colloquially to mean transmission.

management activities, many of which must be undertaken on an hourly and daily basis by PSE's experienced energy traders. PSE also uses modeling tools that assist in projecting whether its power and gas portfolios will be surplus or deficit in future periods. PSE uses these tools to develop and implement hedging strategies to reduce the supply and cost risks associated with the power portfolio volatility.

Q. Please summarize PSE's efforts with respect to developing and implementing hedging strategies for its electric portfolio.

A. PSE manages its electric portfolio within a dynamic and complex environment by relying on:

- internal organizations and highly trained staff dedicated to managing portfolio risks;
- executive and Board of Director-level oversight of staff's portfolio management activities;
- specific procedures and policies governing energy portfolio management activities;
- production cost modeling techniques that develop a 250-scenario probabilistic view of PSE's wholesale electric portfolio and its underlying risks;
- use of programmatic hedging strategies that specify a range of monthly volumes to be hedged, depending upon market fundamentals and energy portfolio management staff's expertise;
- selection of specific commodities to be hedged as informed by Margin at Risk analyses;
- revision of strategies to incorporate up-to-date fundamental views of energy commodity markets;

- a $350 million unsecured revolving credit agreement to support PSE's energy hedging activities; and
- a counterparty credit risk system.

Q. Has PSE revised its hedging strategies since the 2011 GRC?

A. No. PSE's hedging strategy is unchanged since the 2011 GRC.

Q. What are the hedges included in rate year power costs?

A. The rate year power costs include gas for power and power contracts that have been transacted as of March 5, 2013 for delivery during the rate year November 1, 2013 through October 31, 2014.

Table 3 below provides a summary of the fixed-priced rate year power portfolio hedges included in rate year power costs:

Table 3. PSE's 2013 PCORC Rate Year
Short-Term Fixed Priced Power Portfolio Hedges
at March 5, 2013

	Contract	MWh Volume	Rate Year Cost	Average
On-Peak Power Purchases	Fixed	3,725,920	$142,886,692	$38.35
Off-Peak Power Purchases	Fixed	2,157,370	$58,898,765	$27.30
Total Power Purchases	Fixed	5,883,290	$201,785,457	$34.30
On-Peak Power Sales	Fixed	(70,800)	$(2,843,680)	$40.16
Off-Peak Power Sales	Fixed	(49,875)	$(1,560,750)	$31.29
Total Power Fixed Sales	Fixed	(120,675)	$(4,404,430)	$36.50
Net Power Fixed	Fixed	5,762,615	$197,381,027	
Financial Gas for Power (Dth)	Fixed	19,362,500	$86,831,197	$4.48

As discussed below, to determine rate year power costs, the fixed-price gas for power contracts are marked to market in the "Not in Models" calculation and the fixed-price power contracts are included within the AURORA model.[5] In addition, PSE has entered into physical power and gas for power contracts for the rate year which are priced at plus or minus index. The premiums and/or discounts for index contracts are also included in the "Not in Models" calculation.

Q. Please expand on the types of hedges included in rate year power costs.

A. PSE hedges power or gas for power to fix the price of the commodity. PSE utilizes either fixed-for-float index swaps[6] to financially hedge power and natural gas for power or fixed price physical power and gas for power. The mechanics of a financial fixed-for-float index swap, in combination with a physical index purchase, result in a price position identical to purchasing fixed price physical supply.

PSE is enabled to transact with counterparties through standard agreements for financial swaps and fixed price physical power. PSE's market counterparties may only be able to sell physically, financially, or, in some cases, both. Therefore, liquidity is enhanced by transacting both physically and financially.

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5 The AURORA model is discussed in Section VIII. A., Overview of Projected Power Costs for this Proceeding.

6 Fixed-for-float index swaps fix the price of a commodity relative to the market "index" price of a commodity and settlement is done financially. For example, PSE may enter into a fixed-for-float Mid-C power contract for a future month at a fixed price of $32.00 per MWh for all hours of the day ("flat"). When the future month occurs, the contract is settled by comparing the fixed $32.00 per MWh to the market price of, say $35.00 per MWh. In this example, the counterparty would pay PSE the difference between the fixed price and the market price, or $3.00, per MWh. For a 31 day month with 744 hours, this would be a payment of $2,232.

V. BPA 2014-2015 RATE CASE AND BPA TRANSMISSION CONTRACTS

Q. Are BPA transmission rates expected to change during the rate year?

A. Yes. BPA is currently conducting a combined power and transmission rate proceeding to set new rates for BPA's fiscal year 2014-2015, effective October 1, 2013. BPA published a notice in the Federal Register on November 8, 2012, with an Initial Rate Proposal for all transmission and ancillary services (the "BPA 2014 Rate Case"). Please see the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-1T) for a discussion of the BPA 2014 Rate Case, its impact on rate year power costs and PSE's proposal to update power costs during this proceeding to reflect the final BPA 2014 Rate Case rates.

Q. Are there any changes to BPA transmission contracts included in this proceeding?

A. Yes. The proposed power costs include certain costs of renewed and additional BPA transmission contracts. Please see the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-1T) for a discussion of these contracts and their impact to rate year power costs.

VI. WIND RESOURCES

Q. Has BPA's delay in constructing the new Central Ferry to Lower Monumental transmission line affected the operation of Phase 1 of the Lower Snake River Project ("LSR Phase 1")?

A. Not to any significant degree. PSE has been granted firm transmission rights for the first 250 MWs of LSR Phase 1's 340 MW transmission demand[7] and received conditional firm transmission starting December 1, 2012 for the remaining 90 MW until BPA grants firm transmission rights after completion of the new Central Ferry to Lower Monumental transmission line. PSE estimates that there may be a period of a few years with conditional firm transmission for a portion of LSR Phase 1 as BPA reevaluates the Central Ferry to Lower Monumental transmission line construction schedule. As part of PSE's evaluations, curtailment assumptions were made during this period, the impacts of which were reflected in the project economics underlying the Commission's prudence approval for LSR Phase 1 in the 2011 GRC.

Q. Does BPA's delay have a significant effect on power costs in this proceeding?

A. No, LSR Phase 1's generation in this proceeding is equivalent to that in the 2011 GRC in that the projected net capacity factor for LSR Phase I for the rate year is projected to be [redacted] percent rather than the [redacted] percent net capacity factor

7 System losses from the wind turbines to the point of interconnection with BPA reduce the capacity of energy available for scheduling and the required transmission. The estimated system losses for LSR Phase 1's nameplate capacity of 342.7 MW reduce its energy capacity and transmission need to 340 MW.

predicted in the DNV Renewables (USA) Inc. assessment. The difference in generation due to this slightly lowered capacity factor is approximately 5,300 megawatt-hours ("MWhs").

VII. PEAK PLANNING

Q. How does PSE plan to meet winter on-peak demand?

A. PSE must plan to meet the energy demands of its customers across all hours. PSE obtains both long- and short-term peaking resources to meet winter (November through February) on-peak hour loads and to maintain all reliability criteria, such as operating reserves. PSE develops a peak winter plan to ensure that for every on-peak hour of each winter month not only is there physical power available but there is also adequate transmission to deliver such power to PSE's system. PSE relies on its owned and contracted power generating resources, as well as long- and short-term on-peak energy contracts to provide the physical power.

With the Mid-C hub as the primary source of regional power supply, PSE ensures its available transmission capacity from the Mid-C hub to PSE's system is adequate to provide for the forecasted on-peak power needs. Simply put, first PSE compares its available on-peak physical power resources to the on-peak forecasted demand, adjusted for conservation and planning margin, and develops plans to purchase physical on-peak power to the extent it is short power to meet peak customer demand. Second, PSE ensures the physical power may be reliably delivered to its system during the on-peak hours.

Q. Does PSE consider its short-term hedging contracts in determining the resources to meet peak demand?

A. Yes. As I discussed above, PSE reviews its entire physical power portfolio that is available to meet winter peak demand. Long- and short-term power contracts are integral to ensuring adequate physical on-peak power is available to meet peak demand for each of the winter months.

Q. What load forecast does PSE use to determine its on-peak winter demand?

A. PSE uses its most current load forecast approved by the Energy Management Committee, which in this proceeding is the F2012 load forecast.[8] The normal winter peak load forecast is set at the highest historical normal winter peak load, which is the December 23 degree Fahrenheit peak, adjusted to reflect conservation and a planning margin of 15.7 percent. Table 4 shows the forecasted peak load for the winter months of the rate year.

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8 PSE's F2012 load forecast does not include any load forecast for those customers moved to Jefferson PUD on April 1, 2013.

Table 4. Peak MW Load Forecast: Winter 2013/2014

	2013-2014 Winter			
	Nov-13	**Dec-13**	**Jan-14**	**Feb-14**
	30	31	31	28
On-Peak hours	400	400	416	384
All hours	721	744	744	672
	Winter Peak Planning - Physical Power Need (MW)			
Peak Load Requirement without DSR	4,681	4,926	4,710	4,626
15.7% Margin for 5% Loss of Load Probability	735	773	739	726
Demand Side Resource (Conservation)	(134)	(140)	(216)	(197)
Schedule 449 Customers	300	300	300	300
Peak Demand Requirement	5,582	5,859	5,533	5,456

Q. Is PSE's use of a 15.7 percent planning margin appropriate in determining peak needs for the rate year?

A. Yes. PSE's use of a 15.7 percent planning margin is appropriate in determining peak needs for the rate year. The use of a planning margin is consistent with the regional standard formally adopted by the Northwest Power and Conservation Council ("NPCC") to assess the adequacy and reliability of resources within the next five years to meet different uncertainties in loads, hydro, forced outage rates and wind. The NPCC uses the Loss of Load Probability ("LOLP") methodology (as opposed to using historical actuals because historical actuals do not reflect all of the uncertain events that could happen) and has adopted a five percent LOLP standard as a reliability metric. This five percent LOLP standard is calculated to ensure that resources should be adequate to meet loads 95 percent of the time under all combinations of risk events with respect to temperature (loads), hydro, forced outage rates and wind.

PSE has adopted the same methodology and translated the five percent LOLP to a planning standard of 15.7 percent (*i.e.*, the percent over normal peak load that allows PSE to meet the five percent LOLP standard) as described in the 2011 IRP. PSE uses the 15.7 percent planning margin in short-term planning to meet winter peak loads and in long-term planning as presented in PSE's 2011 IRP. PSE is continuously re-evaluating and analyzing its planning assumptions and is currently reviewing its planning margin needs in its 2013 IRP, a draft of which was issued April 1, 2013 ("Draft 2013 IRP"), with the final PSE 2013 IRP to be filed with the Commission by the end of May 2013.

Q. What are PSE's forecast peak planning costs for this rate case?

A. PSE's forecast costs for the rate year to meet the forecast customer normal winter peak demand is $14,380 and represents an approximate $728,000 decrease from PSE's 2011 GRC. This decrease is due to lower forecast customer peak demand due to the April 1, 2013 customer transition to the Jefferson PUD and the benefit of the newly acquired Ferndale Generating Station.

Q. Do you have any more comments regarding PSE's peak planning?

A. Yes. PSE's peak planning was at issue during PSE's 2011 GRC. In its order, the Commssion requested PSE "to provide in its next rate case a more thoroughgoing body of evidence concerning the Company's method" of peak planning and specifically requested "a more accurate representation of the costs of the Company's peak load obligation" and an understanding of how PSE considers hedging contracts to mitigate peak planning exposure.[9] The discussion of PSE's peak planning calculation above responds to the information requested by the Commssion in PSE's 2011 GRC.

VIII. PROJECTED RATE YEAR POWER COSTS

A. Overview of Projected Power Costs for this Proceeding

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

A. PSE's projected rate year net power costs are $738.6 million. Please see Exhibit No. ___(DEM-3) for PSE's projected rate year net power costs. Please also see the Prefiled Direct Testimony of Ms. Katherine Barnard, Exhibit No. ___(KJB-1T), for the adjustment of PSE's projected rate year power costs to test year levels and the Prefiled Direct Testimony of Mr. L. Edward Odom, Exhibit No. ___(LEO-1T), for PSE's projected rate year production operations and maintenance ("O&M") costs.

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9 *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 & UG-111049, Order 08, at ¶ 270 (May 2, 2012) (the "2011 GRC Final Order").

Table 5. Projected Rate Year Power Costs

	($ in thousands)
AURORA	$491,125
"Not in Models"	$247,504
Projected Rate Year Power Costs	$738,629

Q. Please describe how PSE projected its pro forma net power costs in this proceeding.

A. PSE developed projected power costs for the rate year, which for this filing is November 1, 2013 through October 31, 2014. These projections are based on the information available to PSE during the preparation of the initial filing in this proceeding and, except as noted, are consistent with PSE's prior rate cases.

As discussed in the Prefiled Direct Testimony of Ms. Katherine Barnard, Exhibit No. ___(KJB-1T), PSE adjusted the resulting rate year forecast power costs to test year levels by multiplying by a production adjustment factor. This production adjustment factor represents the ratio of adjusted weather normalized delivered energy loads for the test year to the rate year.

Q. How did PSE calculate 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 net power costs for the rate year. The remaining rate year power costs are calculated outside of the AURORA model and are referred to as "Not in Models" costs.

Q. What is the AURORA hourly dispatch model?

A. The AURORA hourly dispatch model is a fundamentals-based production cost model that simulates hourly economic dispatch of PSE's generation resource portfolio within the Western Electricity Coordinating Council region. AURORA produces a forecast of the variable operating costs for PSE's generating resources as well as a forecast of regional power prices.

Q. Were there changes made to the AURORA hourly dispatch model since the 2011 GRC?

A. Yes. EPIS, Inc. ("EPIS"), the developer of the AURORA hourly dispatch model, provides periodic software and database updates. The software version of AURORA used in this filing is 11.0.1091. The database used is the North American Database 2012.01 ("2012.01 Database"), which EPIS issued on October 12, 2012. EPIS updated the resource, demand, financial, and regional data within the 2012.01 Database to reflect more recent data, information and economic conditions than those included in the AURORA database used in the 2011 GRC.[10]

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10 AURORA software version 10.1.1005 was used in the 2011 GRC, along with the North American Database 2010.02.

Q. Do the regional loads included in 2012.01 Database consider the current recession and economic downturn?

A. Yes. The 2012.01 Database reflects a decrease from the 2011 GRC AURORA database in the regional loads AURORA uses to balance against regional resources. The 2012.01 Database reflects a regional load decrease of approximately two percent in both 2013 and 2014 from the regional load in the 2011 GRC AURORA database.

Q. Is AURORA version 11.0.1091 the most recent version of AURORA available?

A. No. EPIS recently issued version 11.2 on April 1, 2013 –- long after PSE had begun its power cost modeling for this filing.

Q. Please explain what data sources are used in the AURORA hourly dispatch model for the gas-fired generators and PSE's intent to update it throughout the proceeding?

A. Based on changing circumstances, PSE periodically updates the operating data of its PSE's generation resources. PSE gas generation resource operating characteristics and assumptions input to the AURORA model represent those at February 28, 2013. Consistent with prior rate cases, PSE proposes to update AURORA throughout the PCORC proceeding to comply with the order in the 2011 GRC that noted 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.[11]

Q. Please explain PSE's projected "Not in Models" power costs that are not calculated within the AURORA hourly dispatch model.

A. Consistent with prior cases, PSE's projected power costs also include costs that are not calculated within the AURORA hourly dispatch model and are called "Not in Models" cost. "Not in Models" costs include items such as fixed coal supply costs, mark-to-market for fixed-price gas for power contracts and basis differentials (fixed-price power contracts are included in the AURORA hourly dispatch model), premiums and discounts associated with contracts priced at plus or minus index, fixed gas transportation charges (variable gas transportation charges are included in the AURORA model), contract costs for the Mid-C hydroelectric projects, amortization of regulatory assets, other power supply costs, peaking capacity costs, wind integration costs, transmission expenses, distillate fuel testing incremental costs, transmission reassignment revenues, charges under purchased power agreements ("PPAs") and any other power supply costs not included in the AURORA hourly dispatch model.

11 2011 GRC Final Order at ¶ 262.

Q. What forward market prices are used in determining the rate year power costs?

A. Consistent with prior proceedings, PSE used the forward electric market prices generated by the AURORA hourly dispatch model. As discussed below, the three-month average gas prices at March 5, 2013, for the rate year, are input to the AURORA model.

B. Power Cost Assumptions

1. Rate Year Power Supply Resources

Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2011 GRC?

A. Yes. A number of changes to PSE's portfolio have already occurred or will occur by or during the rate year (November 1, 2013 through October 31, 2014) for this case. Specifically, the underlying portfolio utilized in determining PSE's rate year power costs for this proceeding:

(i) include the generation for PSE's newly acquired Ferndale Generating Station that PSE purchased and placed in-service mid-November 2012. Ferndale is a combined cycle combustion turbine facility capable of providing 273 MWs of capacity. The rate year includes 356,668 MWhs of forecast power generation from this facility. Please refer to the Prefiled Direct Testimony of Michael Mullally, Exhibit No. ___(MM-1HCT), for a discussion of the Ferndale Generating Station;

(ii) [redacted]

[redacted];

(iii) [redacted];

[redacted]

(iv) reflect the completion of the redevelopment of the Snoqualmie Falls Project prior to the start of the rate year and 262,365 MWhs (30 average megawatts) of power for the rate year. Powerhouse #2 was placed back in service on April 17, 2013 and Powerhouse #1 is planned to be in-service July 2013. Please see the Prefiled Direct Testimonies of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1CT) and Mr. Doug S. Loreen, Exhibit No. ___(DSL-1T) for a discussion of the redevelopment of the Snoqualmie Falls Project;

(v) reflect the completion of an additional 30 MW powerhouse at the Baker Project. The rate year power costs reflect 723,657 MWhs from the Baker Project. The Baker Project upgrades are discussed in more detail in the Prefiled Direct Testimonies of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1CT) and Mr. Doug Loreen, Exhibit No. ___(DSL-1CT);

(vi) reflect an entire year of the twenty-year contract with the Chelan Public Utility District for which the Commission issued a prudence determination in PSE's 2006 general rate case, Docket Nos. UE-060266 & UG-060267 (consolidated) for 25 percent of the output of the Rock Island 1&2 Hydroelectric Project ("Rock Island Project") output effective July 1, 2012. This 25 percent share is a reduction from the 50 percent share contract which expired on June 7, 2012 and provides PSE approximately 156 MW of capacity (as compared to the previous contracted 312 MW) and approximately 92 average megawatts ("aMWs") of energy;

(vii) reflect net lower generation and costs under the Mid-C contract terms with Public Utility District No. 2 of Grant County, Washington ("Grant PUD"). Specifically, PSE's share of the output from the Wanapum Development and Priest Rapids Development Hydroelectric Projects decreased from those included in the 2011 GRC (0.90 percent and 0.84 percent in 2012 and 2013, respectively), to 0.84 percent and 0.64 percent of the combined Priest Rapids Hydroelectric Project projection for 2013 and 2014, respectively;

(viii) reflect changes in the gas pipeline capacity for the power book as discussed in the "Not in Models" adjustments below;

(ix) reflect the expiration on March 31, 2013 of a power purchase agreement with J.P. Morgan Ventures Energy Corporation that delivered 75 MW of power in the first, third and fourth quarters and 25 MW of power in the second quarter at a $[redacted] per MWh flat price;

(x) reflect the expiration on March 31, 2013 of a power purchase agreement with Shell Energy North America (US), L.P. that delivered 50 MW of power around-the-clock, seven days a week at a $[redacted] per MWh flat price;

(xi) reflect the expiration:

(a) on December 31, 2013 of the 3 aMW Nooksack Hydro contract. A new Nooksack Hydro Schedule 91 contract, effective January 1, 2014, is included with the Schedule 91 contracts;

(b) on February 1, 2014 of the Sygitowicz Hydro contract of 0.15 MW;

(c) on December 11, 2013 of the 0.41 MW Qualco Dairy Digester PPA;

(xii) reflect the termination of the Schedule 91 contract with Port Townsend Paper Corporation ("Port Townsend Paper") coincident with the sale of PSE's system in Jefferson County, where Port Townsend Paper resides, to Jefferson PUD on April 1, 2013;

(xiii) reflects new contracts executed under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production";

(xiv) assumes the extension of the PPA to serve the retail load in Point Roberts, Washington past its September 30, 2014 expiration and through the end of the rate year;

(xv) include renewals of BPA transmission contracts, as discussed in the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-1T);

(xvi) reflect new BPA transmission rates, as discussed in the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-1T); and

(xvii) include updates to all rate year power contracts and resources as described above and otherwise to reflect current operations, contract terms and planned maintenance.

2. Projected Hydro Availability

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

A. Consistent with PSE's 2011 GRC and in consideration of the 2009 GRC Order, which noted that future rate cases should include more recent hydro data,[12] PSE has used the average of the 70-year Mid-C streamflow history from 1929 through 1998 to project power costs for the rate year. It is of interest to note that the Commission stated in the 2009 GRC Order:

> Inasmuch as the Company has access to at least some of the more recent data, its power cost evidence in future rate proceedings should include consideration of that data. . . .

12 *See WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶ 124 (Apr. 2, 2010) (the "2009 GRC Final Order").

> . . . . However, we have stated above our preference for using the longest span of years possible.[13]

To be consistent with the Mid-C historical data, PSE used the same 70-year historical west side streamflow records for projections related to PSE's owned hydropower on the west side of the Cascade Mountains. PSE expects an additional ten years of streamflow information to be available for forecasting hydro generation within the next year and will present this data in future rate filings that include power costs.

Q. How does hydro generation affect projected rate year power costs?

A. The 70 years of hydro generation is input into the AURORA model. The AURORA model relies on factors such as supply resources and regional load demand for power and transmission to simulate competitive wholesale power markets in which the regional fleet of generating resources is dispatched to meet regional electric loads. AURORA develops 70 results – one for each of the 70 hydro years – and the average of these 70 AURORA model runs is the AURORA model normalized power costs and generation for the rate year.

Q. Does the AURORA model database used to determine the underlying power costs for this rate proceeding include 70 years of hydro data?

A. Yes. The AURORA model database includes 70-year hydro data (1929-1998) for Pacific Northwest areas. In this regard, PSE's use of the 70 years of hydro

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13 2009 GRC Final Order at ¶¶ 124-125.

generation data for the Mid-C and Westside plants is consistent with the AURORA model.

<u>3. Natural Gas Prices</u>

Q. What natural gas prices did PSE use for the rate year in running its AURORA hourly dispatch model?

A. As the Commission noted in its final order in the 2006 GRC, the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[14] Consistent with this order and all rate cases since, PSE used a three-month average of daily forward market prices for the rate year for each trading day in the three-month period ending March 5, 2013. PSE input these data into the AURORA hourly dispatch model for each of the months of the rate year.

In addition, consistent with prior general rate cases, all previously executed rate year short term power and gas for power contracts at the price cut off date, March 5, 2013, are included in the rate year power costs. Fixed-price short term rate year power contracts are included within the AURORA hourly dispatch model and fixed-price rate year contracts for natural gas for its power portfolio are adjusted outside of the AURORA hourly dispatch model in the "Not in Models" calculations. An adjustment is also included in the "Not in Models" calculation

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[14] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 and UG-060267, Order No. 08 at ¶104 (Jan. 5, 2007).

for premiums and discounts associated with any power and gas for power contracts priced at plus or minus index. These contracts require updating whenever natural gas prices are changed or updated during a proceeding.

Q. Please explain the fixed-price contracts mark-to-market adjustment.

A. The gas price input to the AURORA hourly dispatch model represents a three-month average of the forecast *market* rate year gas prices at a certain point in time (in this case, March 5, 2013). Given PSE's hedging protocol, which includes a programmatic component that requires a specified amount of hedging be done each month, rate year power costs must reflect PSE's actual fixed price gas for power and power rate year contracts as of that date. Hedges are included because forecast rate year power costs consist of two components: (i) costs related to *actual* commitments; and (ii) *forecast market costs* dependent upon the AURORA modeled operational and market fluctuations. The adjustment requires calculating the difference between the three-month average monthly cost of natural gas at the pricing cut-off date (March 5, 2013 in this proceeding) and the monthly average cost of natural gas hedges that have been transacted for the rate year as of the same cut-off date.

For each month of the rate year, this difference is multiplied by the volume of the gas for power hedges transacted for the rate year. The resulting amount represents the "mark-to-market" that is included in the power cost forecast. Including the fixed-price power contracts within the AURORA hourly dispatch model and marking both the fixed-price gas for power and index-based power and gas for power contracts to the three-month average rate year gas price input in the "Not in Models" calculation is consistent with the methodology used by PSE in its 2006 GRC, 2007 PCORC, 2007 GRC, 2009 GRC and 2011 GRC.

Q. How do projected gas prices inputs into AURORA for this proceeding compare with those in the 2011 GRC?

A. Use of a single price can be misleading because there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. Additionally, these prices do not consider the impact of the fixed price gas contracts at the price cut off date which may significantly change the average gas price. For purposes of comparison, however, the average gas price at the Sumas trading hub for the rate year is $4.03 per million British thermal units ("MMBtu") (for the three months ended March 5, 2013), which is $1.13 per MMBtu higher than the average $2.90 per MMBtu price included in the 2011 GRC (for the three months ended April 25, 2012). Table 6 below presents average rate year gas price comparisons.

Table 6. Average Annual Rate Year Gas Prices

Rate Case =>	2013 PCORC	2011 GRC	2009 GRC
3-Mo average at =>	3.05.13	4.25.12	8.13.09
Rate Year =>	Nov 13 – Oct 13	May 12 – Apr 13	Apr 10 – Mar 11
Sumas	$4.03	$2.90	$5.97
Change from Prior	$1.13	($3.07)	

Q. What factors have affected the increase in natural gas prices from the last rate proceeding?

A. In general, it appears that prices have increased from the 2011 GRC because of storage inventory levels. During April 2012, market conditions were very bearish because storage inventory levels in both the U.S. and Canada were at levels well beyond historical averages. For instance, applying the summer 2011 injection profile to the starting April 2012 U.S. storage inventory of 2.4 trillion cubic feet ("TCF") equates to an ending storage inventory of 4.74 TCF, a figure approximately 500 billion cubic feet ("BCF") above estimated maximum storage capacity. This unprecedented starting inventory level created bearish sentiment that permeated through the forward natural gas price curve and contributed to the low average rate year gas prices of $2.90 included in the 2011 GRC. As summer 2012 progressed, above average temperatures in load centers, lower than normal hydro conditions in California, the San Onofre Nuclear Generating Station outage and unprecedented switching from coal to gas-fired generation, resulted in a shrinking of the year-over-year surplus from close to 900 BCF in April 2012 to approximately 100 BCF by the end of injection season in September 2012.

Q. Please explain the source of the gas price inputs.

A. Consistent with prior rate cases, PSE has used forward gas market price data supplied by Kiodex Global Market Data ("Kiodex"). PSE contracts with Kiodex for forward market price data for specific gas and power trading points and for the trading hubs that are input into AURORA.

Kiodex, however, does not offer forward price curves for the Station 2 hub located in British Columbia. Although this price hub is not a trading hub required for input to AURORA, PSE has T-south pipeline capacity between Station 2 and Sumas under contract with Westcoast Energy, Inc. Since the AURORA model uses the input Sumas gas prices for PSE's gas fired generators' dispatch and power costs, PSE must separately consider the cost difference between Station 2 and Sumas, also known as the "basis differential", in the "Not in Models" adjustments.

Since there is no readily available forward gas price for Station 2, PSE has contracted with a third party (Wood Mackenzie) to acquire a forward price forecast of the basis differential between the Alberta Energy Company ("AECO") and Station 2 gas hubs. Specifically, Wood Mackenzie provides an independent forward price forecast of the basis differential between the AECO and Station 2 gas hubs. Because AECO is one of the gas hubs acquired from Kiodex for input to AURORA, PSE may calculate the monthly Station 2 forward gas prices for the rate year by adding the Kiodex AECO forward gas price to the Wood Mackenzie basis differential. In this regard, all gas prices used in the determination of rate year power costs are then based upon forward price forecasts for the rate year period. This methodology is consistent with that explained and used in the underlying power costs approved in the 2011 GRC. The calculation of the Station 2 basis differential is discussed in the "Not in Models" section below.

Q. Does PSE intend to update its projected power costs with updated gas price projections during this proceeding?

A. Yes. PSE intends to update its projected power costs with updated gas price projections because the factors that impact natural gas prices are constantly changing, forward market prices quickly become "stale," and their predictive power with respect to actual future prices decreases with time. Establishing 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 provide a more accurate projection of rate year gas prices. Therefore, PSE will adjust its requested power costs with updated forward market data prior to rates becoming effective. This would also include an update to the short-term fixed-price power contracts that are an AURORA input and the other fixed-price gas for power and index-based power and gas for power contracts that are an adjustment included in the "Not in Models" calculation. In addition, some "Not in Models" adjustments update automatically in the MS Excel files whenever a new AURORA model run download is included in the files.

Q. What is PSE's proposal to update its projected rate year power costs during this proceeding?

A. PSE intends to provide all parties with updated power cost information-–including, but not limited to, updated average gas prices – in a manner and at a date that enables all parties adequate time to review the proposed changes. In this regard and due to the six month term of this PCORC proceeding, PSE proposes to file updated rate year power costs to reflect more recent three month average gas prices four weeks prior to the other parties' response filings, which is estimated to be July 2013.

Q. How do more recent forecast rate year natural gas prices compare to the three-month average at March 5, 2013?

A. As of April 1, 2013, the three-month average rate year Sumas natural gas price has increased to $4.05 per MMBtu, an increase of $0.02 per MMBtu from the $4.03 per MMBtu used to determine the prefiled rate year power costs in this proceeding.

4. Load Forecast

Q. What load forecast did PSE use for the rate year in running its AURORA hourly dispatch model?

A. PSE used the most current electric load forecast, F2012, as the rate year demand input to the AURORA model. This F2012 load forecast was approved by PSE's Energy Management Committee in June 2012. The delivered electric load forecast, net of demand-side resources (conservation), for the November 2013 through October 2014 rate year is 22,890,882 MWhs, or 2,613 aMWs; a decrease of 281,562 MWhs, or 32 aMWs from the 2011 GRC load forecast of 23,172,444 MWhs, or 2,645 aMWs. As noted above, the reduction of customer load as a result of Jefferson County customers transitioning to Jefferson PUD contributed to the electric load decrease. The 2011 GRC load forecast used the then-current load forecast – the F2011 load forecast.

Q. Is the F2012 load forecast the same forecast used in PSE's Draft 2013 Integrated Resource Plan?

A. Yes. PSE's Draft 2013 IRP[15] has used the F2012 load forecast in its underlying analytics. The F2012 load forecast used in this filing includes the reduction for demand side resources ("DSR") while the F2012 demand forecast used in the Draft 2013 IRP is gross of DSR.[16]

Q. Are there other load forecasts besides the F2012 load forecast that are used within analyses presented in this PCORC filing?

A. Yes. Because PSE's load forecast is a key assumption underlying the quantitative analytics to determine PSE's resource needs, the load forecast used within the financial modeling would be the then-current load forecast and could be different than the F2012 load forecast used to determine the rate year power costs for this PCORC. For example, PSE's 2011 Request for Proposals for All Generation Sources (the "2011 RFP") notes that the load forecast was updated "multiple times between the publication of the May 2011 Integrated Resource Plan and completion of the RFP quantitative analyses in May 2012 to reflect the most

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15 PSE's draft 2013 IRP may be accessed at: http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx.

16 Please refer to PSE's Draft 2013 IRP Appendix H, "Demand Forecast" for a detailed explanation of how its underlying demand forecast input was developed.

current information available to us at the time the analysis was conducted." Please see page 1 of the Executive Summary of PSE's 2011 RFP document provided in the Second Exhibit to the Prefiled Direct Testimony of Mr. Michael Mullally, Exhibit No. ___(MM-3HC) and page 91 of the same Exhibit No. ___(MM-3HC) for a graphical comparison of load forecasts over time. Please see the Prefiled Direct Testimony of Ms. Aliza Seelig, Exhibit No. ___(AS-1HCT) for further discussion of the load forecast used in PSE's quantitative analyses.

5. "Not in Models" Adjustments

Q. Has PSE included adjustments in the "Not in Models" that are consistent with the adjustments approved in the 2011 GRC?

A. Yes. Except for the changes discussed in more detail below, PSE has included adjustments in the "Not in Models" calculation that reflect the 2011 GRC Order.

Q. Has PSE included any changes to the "Not in Models" rate year adjustments?

A. Yes. Although the "Not in Models" adjustments are consistent with those presented in the 2011 GRC, below are PSE's proposed changes to the "Not in Models" adjustments:

(i) PSE has included additional fixed gas transportation contracts to support the physical gas requirements of PSE's new Ferndale Generating Station. These contracts are discussed further in the Prefiled Direct Testimony of Mr. Michael Mullally, Exhibit No. ___(MM-1HCT). Accordingly, rate year power costs have increased:

(a) $5.8 million for an additional 33,133 MMBtu per day of gas for power transportation at Station 2; and

(b) $1.0 million for an additional 52,000 MMBtu per day of gas for power transportation on the Cascade pipeline;

(ii) PSE has secured a series of short-term firm transportation capacity release agreements from Northwest Pipeline, GP ("NWP") for Sumas to fill in for expiring agreements and bridge the capacity shortfall until the 50,000 MMBtu per day agreement for service from Stanfield becomes effective November 1, 2014. The 50,000 MMBtu per day contract with Gas Transmission Northwest ("GTN") was discussed in PSE's 2011 GRC. The impact of this "bridge" transportation is that the NWP firm capacity held by the gas for power book remains at a constant total volume of 167,885 MMBtu per day. These short term contracts decrease rate year power costs slightly;

(iii) PSE has assumed the 6,704 MMBtu per day of deliverability and 140,622 MMBtu of storage capacity from the terminated Asset Management Agreement with Cabot Oil & Gas Marketing Corporation. These costs are appropriately reflected as rent expense in production O&M and have been removed from the "Not In Models" calculations - reducing the "Not in Models" costs $0.3 million;

(iv) Fuel handlin**g** costs for Colstrip units 1 through 4 have been included in the "Not in Models" adjustments in past rate proceedings. These costs, however, vary with the quantity of coal burned and have been more appropriately included in the AURORA model variable costs;

(v) The "Not in Models" in this proceeding now include the portion of the over-riding royalties, return on investment, production taxes and royalties for Colstrip units 1 through 4 that are calculated on fixed costs. These costs were included in the AURORA model variable costs in the 2011 GRC. PSE's share of these costs total $5.5 million for the rate year;

(vi) 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 ("Cedar Hills biogas") is included in the "Not in Models" costs and is consistent with the treatment approved in the 2011 GRC. The rate year mark to market adjustment is $2.2 million for the estimated rate year production of 4,568 MMBtu per day. This adjustment, however, is only a placeholder as PSE plans to file an accounting petition that will request to defer the costs and revenues related to biogas. PSE's accounting petition will propose to no longer include the costs of the physical biogas in PSE's baseline rate and instead to defer the cost of the physical biogas along with all other biogas costs and revenues associated with Cedar Hills' biogas for future return to customers. When the outcome of PSE's accounting petition is known prior to the resolution of this PCORC filing, this adjustment will be modified accordingly; and

(vii) Transmission costs include the renewed and additional transmission contracts with BPA as well as BPA's rate increase effective October 1, 2013, as discussed in the Prefiled Direct Testimony of Mr. Tom A. DeBoer, Exhibit No. ___(TAD-1T).

Q. [redacted].

A. [redacted].

Q. What is the mark-to-market adjustment for gas for power contracts included in "Not in Models"?

A. As discussed above, rate year gas for power and power contracts transacted by March 5, 2013, are reflected in power costs. Rate year gas for power contracts at March 5, 2013, were compared to the three-month average gas prices at the same date, resulting in a mark-to-market expense adjustment of $0.9 million. In addition, PSE has included the benefit of its gas transportation contracts in rate year power costs by calculating the basis differential between both its Station 2 and Stanfield gas for power transportation contracts, which reduced rate year power costs by $11.6 million. As noted above, rate year power costs currently include a $2.2 million mark-to-market adjustment for its long term gas for power contract to purchase the Cedar Hills biogas for which PSE will be filing an accounting petition in the near term, requesting Cedar Hills costs be removed from the baseline rate. Lastly, consistent with the 2011 GRC, rate year power costs have been reduced $0.5 million to recognize the benefit of PSE's gas for power storage contracts. The mark-to-market adjustment for gas for power contracts reduces rate year power costs by $9.1 million.

IX. COMPARISON OF PROJECTED POWER COSTS TO THE PROJECTED POWER COSTS IN THE 2011 GRC

Q. What are the principal differences between the power cost projections in this proceeding and the power cost projections approved in the 2011 GRC?

A. The power cost projection in this case is approximately $71.5 million *lower* than the power costs projections approved in the 2011 GRC. Please see Exhibit No. ___(DEM-4C) for a resource by resource comparison of the projected power costs and generation for the 2011 GRC rate year (May 1, 2012 through April 30, 2013) and the projected power costs for the rate year in this proceeding (November 1, 2013 through October 31, 2014).

Q. What are the causes of the change in projected power costs relative to the 2011 GRC?

A. The following items caused the majority of the change to projected rate year power costs from the 2011 GRC:

(i) lower costs due to the expiration of two purchased power contracts noted above which have been replaced with lower priced market power;

(ii) lower costs due to lower fixed-price short term power and gas for power contracts;

(iii) lower costs due to increased hydro generation of 262,365 MWhs (30 aMW), due to the redevelopment of the Snoqualmie Falls Project;

(iv) decreased Mid-C contract costs due to ownership changes from the Chelan PUD contract and higher Reasonable Portion revenues under the Grant PUD contract;

(v) a reduction of 32 average megawatts of forecast load from the 2011 GRC rate year due mainly to the reduction of customer load as a result of Jefferson County customers transitioning to Jefferson PUD effective April 1, 2013;

(vi) a net increase in Colstrip generation caused by less planned outage days than was included in the 2011 GRC. Rate year power costs reflect only one planned major outage of [redacted] days for Unit 3 as compared with two planned major outages which overlapped into the rate year for the 2011 GRC power cost forecast. In addition, all Colstrip units' generation were lowered slightly due a higher four-year average forced outage rate than the 2011 GRC, as discussed in the Prefiled Direct Testimony of Mr. Ed Odom, Exhibit No. ___(LEO-1CT);

(vii) increased costs due to higher rate year average gas prices and AURORA-derived rate year market power prices, as discussed above, and decreased market heat rates which lessened the dispatch of gas fired generators and reduced rate year generation;

(viii) increased BPA transmission tariffs effective October 1, 2013, as discussed above;

(ix) the addition of the Ferndale facility, as discussed above, which adds 356,668 MWhs (41 aMW) of power generation as well as additional fixed gas transportation contracts; and

(x) updates for new, existing and expiring purchase power agreements.

X. INTRODUCTION OF PSE WITNESSES

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

A. The following additional witnesses present direct testimony on PSE's behalf:

Mr. Roger Garratt, Director of Financial Planning & Strategic Initiatives for PSE, presents PSE's strategy to fulfill long-term capacity and renewable resource needs; challenges and opportunities that affect PSE's ability to acquire electric resources; and an overview of PSE's prudency requests.

Mr. Michael Mullally, Senior Energy Resource Planning & Acquisition Analyst for PSE, describes PSE's 2011 Request for Proposal process and the quantitative and qualitative evaluation of the acquisition of the Ferndale Generating Station, [redacted].

Mr. Tom DeBoer, Director of Energy Supply Operations Policy, Planning and Compliance for PSE, provides a summary of the BPA 2014 rate case and prudence support for PSE's new and extended transmission contracts with BPA.

Ms. Aliza Seelig, Consulting Energy Resource Planning & Acquisition Analyst for PSE, describes the quantitative analyses undertaken by PSE in considering resource acquisition decisions and the new and renewed transmission contracts with BPA.

Mr. Matthew D. Rarity, Manager of Power and Gas Supply Operations for PSE, describes wind integration costs and provides details of data utilized to model and the modeling of PSE's costs to integrate wind resources.

Mr. L. Edward (Ed) Odom, Director of Thermal Resources for PSE, summarizes the rate year production O&M costs and provides details of the production O&M for PSE's thermal generation fleet, including asset information for the Ferndale Generating Station.

Mr. Paul K. Wetherbee, PSE Director of Hydroelectric and Wind Resources Assets Management for PSE, describes the Baker and Snoqualmie Falls Project license implementation, [redacted], and production O&M for PSE's hydro and wind facilities.

Mr. Doug Loreen, Director of Project Delivery for PSE, describes the Baker and Snoqualmie Falls Projects.

Ms. Katherine Barnard, Director of Revenue Requirements and Regulatory Compliance for PSE, presents the electric results of operations and revenue requirement and power cost baseline rate as well as the allocation of [redacted] and the deferrals for the Snoqualmie and Baker Projects and the Ferndale Generating Station.

Mr. Jon Piliaris, Manager of Pricing and Cost of Service for PSE, presents PSE's electric cost of service, rate spread and rate design.

XI. CONCLUSION

Q. Please summarize your testimony.

A. PSE's acquisition, rebuilding and [redacted] of the resources identified in my testimony has helped to provide the resources needed to serve electric customers and has clearly met the Commission's standard for prudency. PSE's long-term electric acquisition program continues to succeed in renewing PSE's resources and bringing into PSE's portfolio acquisitions that have been thoroughly analyzed and that meet customer load requirements at a reasonable price.

PSE actively manages the power and gas cost risks faced by its customers in order to keep power costs as low as reasonably possible. PSE's $738.6 million projected rate year power costs for this proceeding are consistent with, and based on, sound assumptions using methodologies approved by the Commission in PSE's prior general and power cost only rate cases.

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.

REDACTED