EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-14____
PCA 12 COMPLIANCE
WITNESS: DAVID E. MILLS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For Approval of its March 2014 Power Cost Adjustment Mechanism Report**	**Docket No. UE-14____**

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

REDACTED VERSION

MARCH 31, 2014

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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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 N.E. Fourth Street, Bellevue, Washington, 98004-5591. 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?

A. As Vice President, Energy Supply Operations, I am responsible for the oversight of PSE's Power & Gas Supply Operations, Load Serving Operations, Transmission Contracts and Energy Supply Operations Policy, Planning & Compliance groups. This includes management of PSE's short- and medium-term wholesale power and natural gas portfolios (up to three years) and involvement with planning for long-term supply requirements in addition to PSE's transmission functions as they pertain to the Load Office and operating the Balancing Authority.

Q. Please summarize the contents of your testimony.

A. First, I provide some brief background information regarding the Power Cost Adjustment ("PCA") Mechanism and how it addresses the volatility of PSE's power costs. I then describe the changes in power resources from those included in current rates, as well as PSE's efforts to manage, control and moderate its power costs during the period that began on January 1, 2013 and ended on December 31, 2013 ("PCA Period 12"). I then compare PSE's actual power costs for PCA Period 12 to its baseline power cost rates that were in effect for PCA Period 12. See the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-1T), for further information regarding the PCA baseline rates for the PCA Period 12. Finally, I discuss PSE's Environmental Attributes transactions for the PCA Period 12.

The baseline power cost rate from PSE's 2011 general rate case, WUTC Docket No. UE-111048 ("2011 GRC") was in effect through October 31, 2013. The baseline power cost rate per the 2013 Power Cost Only Rate Case, WUTC Docket No. UE-130617 ("2013 PCORC") went into effect November 1, 2013.

II. BACKGROUND REGARDING THE PCA MECHANISM

Q. Why does PSE have a PCA Mechanism?

A. The parties to PSE's 2001 general rate case were keenly aware from the experience of the Western Power Crisis in 2000-2001 how volatile power prices can be. In response to that potential volatility, uncertainty in the wholesale energy markets and PSE's need to add resources to meet its load obligations, the parties who

participated in the PCA settlement collaborative in PSE's 2000-2001 general rate case agreed to a negotiated PCA Mechanism. The Commission approved the PCA Mechanism in its Twelfth Supplemental Order in PSE's 2011 GRC. The PCA Mechanism became effective July 1, 2002.

Q. Please describe why PSE's power costs can be volatile.

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: (1) streamflow variation affecting the supply of hydroelectric generation; (2) weather uncertainty affecting power usage; (3) variations in market conditions such as wholesale gas and electric prices; (4) risk of forced outages; (5) variability of wind generation; and (6) transmission and transportation constraints. All of these have an impact on load and resource volatility, which PSE may balance with wholesale market purchases and sales.

Q. How does the PCA Mechanism work?

A. Generally, the PCA Mechanism is an annual accounting process to share costs and benefits between PSE and its customers over four graduated levels (so-called "bands") for the first $120 million of power cost variances. For power cost variances over $120 million, the PCA sharing mechanism allocates 95 percent of costs or benefits to customers and the remaining 5 percent of costs or benefits to PSE.

Q. What do you mean by "power cost variances"?

A. Power cost variances are the annual difference between (1) the "baseline" fixed and variable power costs that are built into PSE's electric rates and (2) the sum of PSE's actual variable power costs allowed under the PCA Mechanism plus the fixed power costs, as determined in the most recent rate proceeding. For example, during PCA Period 12, PSE's actual power costs were $37.8 million below the amounts recovered through the power cost baseline rate. PCA Period 12 actual power costs are discussed in more detail in section IV.C of my testimony. See the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-1T), for further information and discussion of the PCA Annual Report for PCA Period 12.

Q. How are PSE's costs for new resources treated in the PCA Mechanism?

A. Under the PCA Mechanism, new resources with a term *less* than or equal to two years are included in allowable PCA costs. The prudence of such resources is determined in the Commission's review of the annual PCA true-up. Power costs related to a new electric resource with a term *greater* than two years are included in allowable PCA costs through a bridge mechanism, known as PCA Exhibit G, "New Resource Adjustment". Exhibit G reduces the PCA mechanism's variable costs of the new resources to the lower of actual unit cost or the baseline rate until the prudence of such resources can be reviewed and approved in a power cost only or general rate case.

Q. Were there new resources that triggered the PCA Exhibit G calculation during the PCA Period 12?

A. No. There were no new resources that triggered the PCA Exhibit G calculation during PCA Period 12, as discussed later in my testimony.

III. PCA PERIOD 12 POWER COSTS

A. PCA Period 12 Power Resources

Q. What are the changes to long-term electric supply resources that were different than those included in the baseline rates during PCA Period 12?

A. As noted above, the baseline rates in effect during the PCA Period 12 reflect the power portfolio from PSE's 2011 GRC through October 31, 2013 and from PSE's 2013 PCORC beginning November 1, 2013. There were a number of changes to PSE's portfolio that were reflected in the PCA Period 12 power costs that were different than those recovered in rates for the entire PCA Period 12. Specifically, PCA Period 12 actual power costs included:

(1) Energy from newly acquired and upgraded resources which were included in the baseline rate effective November 1, 2013 as they were deemed prudent in PSE's 2013 PCORC. Note that none of these resources were subject to an adjustment under Exhibit G, as is discussed in the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-1T):

a. A full year of the generation from PSE's acquisition of the Ferndale 270 MW Ferndale Generating Station ("Ferndale"), a combined cycle natural gas-fired power plant, from Tenaska Washington Partners, L.P. that was placed into service on November 15, 2012;

b. the renovation and upgrades at the Snoqualmie Falls Project to implement the Federal Energy Regulatory Commission (FERC) license. Powerhouse #1 and #2 were

placed in service during 2013 and provided 76,133 MWhs of power for the PCA Period 12; and

c. the addition of a fourth 30 MW generator unit at the Baker Project to implement the FERC license;

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

(3) Reflect the expiration:

a. 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;

b. 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;

c. on December 11, 2013 of the 0.41 MW Qualco Dairy Digester purchased power agreement ("PPA");

(4) reflect a reduction of load delivered to customers as a result of Jefferson County customers transitioning to Jefferson County Public Utility District No. 1 ("Jefferson PUD") effective April 1, 2013;

(5) 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;

(6) Include additional fixed gas transportation contracts to support the physical gas requirements of PSE's new Ferndale Generating Station, which were deferred as discussed in Ms. Katherine J. Barnard's Exhibit No. ___(KJB-1T):

a. for an additional 33,133 MMBtu per day of gas for power transportation at Station 2; and

b. for an additional 52,000 MMBtu per day of gas for power transportation on the Cascade pipeline;

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

Q. Did PSE acquire any new resources during PCA Period 12 with a term of less than or equal to two years?

A. Yes. PSE acquired such resources in connection with short- and intermediate-term off-system physical or financial purchases and sales of power and fuel to generate power. The majority of such transactions during this period were short-term balancing transactions of power and natural gas for power purchases and sale contracts. Such balancing transactions are made in response to changes in load or resource availability as well as changes in market heat rates, which guide PSE decisions of whether to dispatch gas-fired generation or to buy or sell power versus natural gas for power. Such transactions include intermediate term transactions entered into pursuant to PSE's programmatic portfolio hedging efforts.

PSE also purchased winter on-peak index power to secure firm power supply to PSE's system.

Q. Why did PSE enter into the various transactions described above?

A. These transactions were undertaken within a comprehensive portfolio and risk management system of organizational structure, technological tools, and human resources designed to allow PSE to: (1) deliver reliable energy when its customers demand it; (2) serve its customers while mitigating price volatility; and (3) enhance the utilization of PSE's energy resources.

PSE has had organizational structures, policies and overarching strategies in place for many years to provide oversight and control of energy portfolio 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 months. PSE uses these tools to develop and implement strategies to reduce the cost risks associated with portfolio volatility.

The following section of my testimony first provides a description of these systems and tools. I then illustrate their application to PCA Period 12 by describing actual hedging strategy decisions and their execution undertaken by PSE with respect to its power supply for a sample month, June 2013. *See* Exhibit No. ___(DEM-3C).

B. PSE's Management of its Power Portfolio and Related Fuel Supply for PCA Period 12

1. Overview of PSE's Portfolio and Risk Management Systems

Q. What organizational structures are in place to provide oversight and control of power portfolio management activities?

A. During PCA Period 12, PSE's Energy Supply Merchant ("ESM") department included certain employees performing Portfolio Hedging and Power and Gas Supply Operations functions. The ESM department is composed of energy market analysts, quantitative analysts, seasoned energy traders and other professionals. The ESM department is responsible for identifying, quantifying, monitoring and recommending risk management strategies for PSE. The ESM department performs these tasks and manages PSE's short- and medium-term portfolios. During PCA Period 12, the ESM was led by the Vice President, Energy Supply Operations.

The Energy Risk Control ("ERC") department includes the employees who perform

credit analysis and is also responsible for providing risk control oversight. The ERC department is led by the Corporate Treasurer.

PSE's Energy Management Committee ("EMC") – composed of five senior PSE officers – oversees the activities performed by the ESM department. The EMC is responsible for providing oversight and direction on all portfolio risk issues in addition to approving long-term resource contracts and acquisitions. The EMC provides policy-level and strategic direction on a regular basis, reviews position reports, sets risk exposure limits, reviews proposed risk management strategies, and approves policy, procedures and strategies for implementation by PSE staff. In addition, PSE's Board of Directors provides executive oversight of these areas through the Audit Committee.

Q. What hedging strategies have been approved by the EMC?

A. With respect to hedging strategies for specific time periods or quantities of energy, the EMC has approved a Programmatic Hedging Strategy. The original programmatic hedging strategy was approved by the EMC on July 22, 2004, with a PSE staff transactional purview of [redacted]. The term of the EMC approved programmatic hedge strategy originally consisted of the last [redacted] of the [redacted] purview ("Programmatically Managed Hedge"), but was reduced to [redacted] in early 2006. The balance of the [redacted] purview were actively managed ("Actively Managed Hedge") in accordance with the EMC approved Energy Supply Hedging and Optimization Procedures Manual ("Procedures Manual"). In October 2007, PSE extended department staff's transactional purview

from [redacted] to [redacted]. At that time, the balance of the current month plus the first full [redacted] became the Actively Managed Hedge in accordance with the Procedures Manual and the latter [redacted] (the period always includes a full quarter so varies from being [redacted]) became the Programmatically Managed Hedge in accordance with the EMC approved strategy. ESM department staff utilizes the Programmatically Managed Hedge to systematically reduce PSE's net power portfolio exposure beginning [redacted] in advance of the month in which the power will be needed to serve PSE's load. This process is described in greater detail below and in Exhibit No. ___(DEM-3C), which also steps through a sample month, June 2013. Such exposure reduction is subject to minimum and maximum monthly limits to reduce timing and market risks associated with hedging activities.

Pursuant to the hedging strategies in effect during the PCA Period 12, by at least [redacted] prior to delivery, the bulk of the hedging strategies and transactions have been made, leaving primarily only balancing transactions needed to respond to changes in market heat rates, load, hydro conditions, unit assumptions and other portfolio changes. Decisions about hedges for delivery during the Actively Managed Hedge are made by ESM department staff, within limits set out in PSE's Procedures Manual.

Q. How does PSE integrate hedging activities with its power portfolio modeling?

A. PSE's risk system employs production cost modeling techniques to estimate future demand for on- and off-peak power and natural gas for PSE's fleet of gas-fired power plants. This risk system permits PSE to model scenarios of prices, hydro

conditions, load projections, generating and contracted resources and other inputs as required to represent future projected portfolio needs.

To model a variety of scenarios regarding PSE's gas-fired generation, the risk system takes into account each plant's individual operating characteristics, including: unit efficiency, start-up costs, variable operating costs, minimum run times, planned and unplanned outages, and unit availability. The risk system performs simulations of different market conditions and various outages in order to develop an estimate of the gas volumes required to produce a volume of power. The plants are modeled on an hourly basis and the information is aggregated into daily and monthly time frames for purposes of developing a forward-looking position. The risk system incorporates information about hedges that PSE staff has already executed to model whether the portfolio is surplus or deficit. The risk system incorporates the inter-relationship between gas and power prices in developing its probabilistic gas and power positions. In different market scenarios, PSE's gas or power requirements will change. The reason for this is twofold. First, the plants have different operating efficiencies (known as "heat rates") and become economic to dispatch at different price differentials between power and gas. Second, the forward market prices for power and gas change frequently and the price relationship between power and gas, known as the "implied market heat rate", change as well. At certain implied market heat rates, PSE will expect to run each plant at an expected rate, and the total of all the plant requirements can be calculated. But if market conditions change, PSE will expect to adjust its gas and power purchases and sales in order to serve load with the most economic resources.

For example, it may be more economical to purchase power than to purchase gas to generate the power PSE needs to serve its load.

Q. Please describe the output that the electric portfolio risk system produces.

A. The risk system generates a probabilistic volumetric position report, comprised of 250 scenarios, for on- and off-peak power and gas for power. The position report shows, for each of the months following the date of the report, the resource types in PSE's power position grouped by: short-term purchase and sale transactions, long-term contracts, Combustion Turbines ("CT") grouped by heat rate efficiency of the facilities, Non Utility Generators/Qualifying Facilities ("NUGs/QFs"), Coal Plants, Wind and Hydro (both PSE-owned and Mid-C contracts). Based on this volumetric position for each month, the risk system also generates the potential exposure associated with the "open" positions (defined as any net surplus or deficit amount as compared to the load demand). *See* Exhibit No. ___(DEM-4C).

Q. How does PSE use the electric portfolio risk system to help make hedging decisions?

A. Once PSE's aggregated energy position and net exposure are defined for a particular period, the ESM department evaluates and develops risk management strategy proposals and/or executes transactions around the purchase or sale of gas or power, as appropriate, to ratably move toward a balanced position and reduced exposure. Execution entails entering into specific transactions with approved counterparties, approved instruments, executed master agreements and available credit.

Q. How does PSE use the risk system to implement its Programmatic Hedging Plan?

A. As described above, PSE's Programmatic Hedging Plan is set up to systematically reduce the total net exposure for each of the [redacted] beyond the next [redacted] timeframe, within maximum and minimum limits on the amount of hedging that can or must be done each month, so that the total net exposure for each month will fall within the limits set forth in the Procedures Manual. Every month, the risk system calculates the total net exposure to be reduced for each of the [redacted] in the Programmatically Managed Hedge period.

Q. Does Energy Portfolio Management staff implement the Programmatic Hedging Plan by relying only on the net exposure?

A. No. The net exposure drives transactions only to the point of showing whether PSE's exposure is within the maximum and minimum monthly limits of the plan. ESM department staff must then make use of market fundamentals, water supply and weather forecasts that impact the wholesale electric and gas markets to decide whether to press toward the maximum or minimum monthly limits, or somewhere in between. ESM department staff also determines when and how to execute such transactions to maintain each months net exposure reduction within the maximum and minimum limits.

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Q. How does PSE's staff develop a view of appropriate hedging strategies for the power portfolio?

A. The ESM department utilizes a wide set of tools and sources of information to help them make informed decisions about dispatching plants, purchasing fuel and executing hedges approved by the EMC. They also hold meetings each month so that the teams can review operational events, discuss market trends, fundamentals and technical analysis and review supply and demand information. Within this context, the teams work together to understand the exposures in the portfolio and discuss where hedging priorities occur. Underlying all this teamwork is an ESM department staff with years of experience in energy trading, optimization and risk management.

Q. What types of information does the Energy Portfolio Management staff consider?

A. The ESM department collects a wide range of data to monitor supply/demand factors, which include but are not limited to: weather trends; macro economic factors; crude oil markets; gas storage inventories across the United States, Canada and in the western United States; hydro run-off forecasts; reservoir storage; precipitation and snow pack; and more. Additionally, PSE staff review forecasted wholesale market prices and supply/demand fundamentals, such as trading firm publications and consulting service forecasts.

ESM department staff also receives real-time information from a variety of sources such as: McGraw Hill (Gas Daily, Megawatt Daily), Future Source;

Intercontinental Exchange (live price data); live broker lines where current transactions are communicated through a speaker system, and other tools. The ESM department also has instantaneous data coming from PSE's systems operations staff so they can view load and generation dispatch data on a real-time basis.

In addition to using such information and processes to implement the current Programmatic Hedging Plan, the ESM department also uses such information to develop recommendations to the EMC regarding potential changes to PSE's overarching hedging strategies or to recommend transactions that do not fall within those strategies.

Q. Does PSE use any other tools to manage its energy portfolio?

A. Yes. PSE uses a counterparty credit risk management system in establishing and monitoring counterparty credit limits. Counterparty exposure is calculated and monitored daily and PSE staff is permitted to transact only within the established credit limits.

Q. What guidance does PSE have in place for approaching risk management strategy proposals?

A. Many years ago, PSE moved from a more "discretionary" model of making hedging decisions to a more "programmatic" approach to hedging. The preceding dollar-cost averaging strategy established a disciplined approach to purchasing a defined volume of gas or power on a monthly basis. In applying this strategy, PSE typically

established plans to purchase hedges for specific forward time periods, with the goal of purchasing a defined amount of power and gas in order to ratably reduce the deficit positions by a small amount each month.

By spring 2003, the EMC had approved expansion of this concept to an "Exposure-based Dollar Cost Averaging." This refinement moved PSE from defining a specific commodity and volume to be hedged every month to a dollar amount of risk reduction to be accomplished every month. Under this approach, the EMC would approve a dollar figure of risk to be reduced, and PSE staff would determine whether it was better to hedge gas or power. As market prices move up or down, the dollar amount allows for less or greater volumetric purchases of power or gas for power.

In May 2004, during PCA Period 2, PSE began to employ a metric called Margin at Risk ("MaR"), which measures risk reduction as a result of incremental hedging. *See* Exhibit No. ___(DEM-5C). PSE has incorporated the MaR concept into the evaluation process for hedge strategies to measure risk reduction for various alternatives. A series of hedge strategies (transaction types) are run through the portfolio, providing a table of how much risk reduction is gained by month and by strategy. The MaR concept assists with deciding how to allocate dollars in a credit-constrained environment, thus providing an additional tool for choosing between available commodities. *See* Exhibit No. ___(DEM-6C).

In July 2004, the EMC approved a continuation of a dollar cost averaging strategy (hedging on a regular schedule over a lengthy period) informed by MaR. However,

the EMC directed that PSE staff monitor and more actively address the exposure associated with PSE's power portfolio position [redacted] ahead of the time the power would be needed. On January 7, 2006, the Rolling [redacted] Hedging Plan was amended to be a Rolling [redacted] Hedge to guide hedging decisions for the [redacted] to [redacted] time frame. In October 2007, this hedging plan was extended and now covers the [redacted] to [redacted] time frame ("Programmatically Managed Hedge"). This hedging plan reduced hedge concentration by extending the dollar cost averaging approach to a longer period of time, and increased staff's ability to react to position changes as a result of forecast customer demand, stream-flow variations, forced thermal plant outages, and changing market conditions.

ESM department staff use the Programmatically Managed Hedge to systematically reduce PSE's net power portfolio exposure (including natural gas for power generation) beginning [redacted] in advance of the month in which the power is needed to serve PSE's load.

Q. How does the Programmatically Managed Hedge Plan work?

A. As mentioned above, in October 2007, PSE extended staff's transactional purview from [redacted] to [redacted]. At that time, the first [redacted] became the Actively Managed Hedge in accordance with the Procedures Manual and the remaining [redacted] became the "Programmatically Managed Hedge" in accordance with the EMC approved strategy. The revised strategy retained many of the same features as the previous hedging strategy. These include

(i) a required ratable reduction of monthly commodity exposure

removed each month;

(ii) the volume of monthly hedging and intra-month timing for hedging is informed by market fundamentals; and

(iii) hedging targets are established on the basis of the minimum or maximum amount of commodity exposure allowed under the EMC approved strategy.

The revised plan requires that on or before [redacted] ahead of delivery, the bulk of the hedging strategies and transactions have been made per this programmatic plan. These revisions enable PSE to monitor and more actively address the exposure associated with PSE's power portfolio position [redacted] ahead of the time the power would be needed to serve load.

Q. Why did PSE extend its hedging strategies?

A. Prior to extending the term of the hedging strategies, PSE engaged in a very detailed best-practices benchmarking and market research initiative. These efforts revealed that customers prefer a longer period of rate stability and that industry leading companies were engaged in longer term hedging practices than PSE. Given this and other information, PSE determined it could be beneficial to expand its hedging horizons.

2. Application of PSE's Risk Management System to PCA Period 12 Power Costs

Q. Would you provide some examples of how PSE applied the risk management systems, tools and strategies described above with respect to PCA Period 12 power supply and costs?

A. Yes. Take, for example, PSE's energy requirements for June 2013. Beginning in

[redacted], the power supply for June 2013 rolled into staff's Programmatically Managed Hedge purview. PSE's ESM staff began to actively reduce spot market price exposure for the delivery period June 2013. From [redacted] through [redacted] on a monthly or bi-monthly basis, ESM department staff developed strategies to reduce PSE's exposure with respect to its electric supply needs for June 2013. Such strategies reflected updated Position and Exposure Reports generated by PSE's risk system, market heat rates, hydro conditions and weather fundamentals, and other available information. In accordance with the EMC approved Programmatic Hedging Plan and within the limits described therein, PSE staff executed these strategies by entering into hedging transactions. ESM department staff can make recommendations to depart from this plan, but execution of such hedges is subject to EMC approval. With respect to the June 2013 power supply, ESM department staff did not make any such recommendations, but instead kept the EMC informed of its analyses and activities. See Exhibit No. ___(DEM-3C) for discussion of the hedges transacted for June 2013, which are presented in Exhibit Nos. ___(DEM-7C) and ___(DEM-8C).

Beginning in [redacted], the power supply for June 2013 rolled into staff's Programmatically Managed Hedge purview. Beginning in [redacted], the power supply for June 2013 rolled into staff's Actively Managed Hedge - at which point staff continued to analyze PSE's position for June 2013 on a daily basis and, based on market conditions and other information available to them at the time, took actions to reduce PSE's exposure under the authority and limits of the Procedures Manual.

Documenting these activities requires detailed description and explanation of the information and reports used by PSE at each stage of its consideration, decision making, and execution of PSE's risk management strategies. Thus, this description and documentation is presented separately as Exhibit No. ___(DEM-3C).

Q. Are the activities described in Exhibit No. ___(DEM-3C) the only risk management activities that PSE undertook for PCA Period 12?

A. No. Similar activities were undertaken with respect to managing PSE's portfolio and exposure for the entire PCA Period 12.

3. Winter Peaking Contracts

Q. Why does PSE enter into winter peaking contracts?

A. Winter peaking contracts are procured so that PSE will be able to reliably serve high loads that occur during an extreme winter peak event by locking in firm physical supply.

Q. How did PSE approach the decisions of whether and how to enter into winter peaking contracts for the winter months of calendar 2013?

A. PSE approached these decisions within the context of its portfolio and risk management systems and procedures.

PSE specifically considered how it should plan for and execute contracts to provide peaking capacity or related hedges. As part of that assessment, PSE considered entering into various call options versus "self-insuring" against extreme winter peak

events. PSE ultimately decided that it would purchase several winter on-peak power index transactions to ensure firm physical power supply during the winter peaking hours.

C. PSE's PCA Period 12 Actual Power Costs

Q. How have PSE's recoveries of power costs compared to those set in rates?

A. During PCA Period 12, PSE's rates have over-recovered actual power costs by $37.8 million. As a result of the PCA sharing bands, PSE customers will share $8.9 million of this over-recovery and PSE will retain the remaining $28.9 million.

Q. Why do actual power costs differ from those set in rates?

A. The actual costs of power delivered to PSE's system will always differ from those set in rates as they reflect the actual resources available to PSE, as discussed above and the actual outcome of power costs variables, which include, for example:

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

(ii) weather 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;

(vi) differences in actual resources in the power portfolio versus those set in rates due to contract expirations, contract changes and resource acquisitions; and

(vii) transmission and transportation constraints.

Although power costs set in rates are estimated "as closely as possible to costs that are reasonably expected to be actually incurred,[1]" they are still forecasts of future events, which are further limited by regulatory normalizing assumptions. Specifically, current ratemaking normalizes the power cost volatilities by employing:

(i) a 70-year hydro data set to determine hydro generation;

(ii) a weather normalized load forecast;

(iii) a three-month average forward gas price forecast;

(iv) model generated forward power prices;

(v) historical average forced outage rates; and

(vi) forecast average wind generation.

Q. What caused the difference during PCA Period 12 between PSE's actual power costs and power costs recovered in rates?

A. PSE's $37.8 million over-recovery of amounts recovered through the Power Cost Baseline Rate during the PCA Period 12 was due to lower power costs which were mitigated by lower baseline rate revenues. The power costs included in PSE's 2013 PCORC baseline rate effective November 1, 2013 were reduced by nine percent – $75.8 million - from those included in PSE's 2011 GRC baseline rate due mainly to changes in resources and lower forecast load[2]. Many of the same factors

[1] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos UE-040640, *et al.*, Order 06 at ¶108 (Feb. 18, 2005).

[2] *See* the Prefiled Direct Testimony of David E. Mills in PSE's 2013 Power Cost Only Rate Case, Docket No. UE-130617.

contributing to the $75.8 million reduction in PSE's baseline rate were the cause of PSE's lower power costs during calendar 2013. The key drivers were: i) replacing power from long-term fixed priced PPA's with J.P. Morgan Ventures Energy Corporation and Shell Energy North America (US), L.P.[3] with lower priced market purchases; ii) replacing gas fired generation that was not economically dispatched due to low market heat rates with lower priced market purchases and iii) lower customer demand as a result of Jefferson County customers transitioning to Jefferson PUD effective April 1, 2013. Lower power costs were mainly offset by i) lower delivered loads which reduced baseline rate revenues; and ii) the forced outage at the Colstrip Unit 4 generating facility that occurred the first week of July 2013 and continued into the first quarter of 2014.

The 2011 GRC baseline rate was in effect ten months of the calendar year 2013. Though market prices were on average higher, actual market prices for gas in 2013 were well below prices included in the 2011 GRC baseline rate which reduced the average market heat rate and decreased gas fired generation for the first ten months of 2013. The displaced gas fired generation was replaced with lower priced market power, thus reducing power costs as compared to rates for the first ten months of the year. For the two months the 2013 PCORC rates were in effect, just the opposite occurred; however, overall for the calendar 2013, the lower gas fired generation contributed to power cost over-recoveries in the PCA mechanism. While market prices alone do not consider the impact of the fixed price contracts, for

[3] These two PPAs expired March 31, 2013.

purposes of comparison, Table 1 presents a comparison between average market prices during calendar year 2013 to the average prices embedded in the 2011 GRC baseline rate and 2013 PCORC baseline rate.

Table 1: Average Power and Gas Price Comparison
Calendar Year 2013 Compared to Prices in Rates

	2011 General Rate Case			2013 Power Cost Only Rate Case		
	Actuals Jan-Oct	Rates Jan-Oct	Diff Jan-Oct	Actuals Nov-Dec	Rates Nov-Dec	Diff Nov-Dec
MidC Flat	$ 27.17	$ 25.38	$ 1.79	$ 42.64	$ 32.60	$ 10.04
Sumas	$ 3.56	$ 4.61	$ (1.04)	$ 2.80	$ 4.23	$ (1.43)
Flat Heat Rate	7.73	9.20	(1.47)	9.18	7.71	1.47

PSE's 2011 GRC power costs included costs associated with two PPA's to purchase 125 MW of power – both of which expired March 31, 2013. Table 2 below reflects the cost and generation associated with the PPAs that were included in the 2011 GRC baseline rate that was in effect through October 31, 2013 compared to the actual costs for PCA Period 12.

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Table 2: Two PPA's Expired March 31, 2013
PSE's 2011 GRC Baseline Rates
Compared to Actual Costs for 2013

	Cost	MWh	$/MWh
In Rates through 10.31.13	[redacted]	748,800	[redacted]
Actual Costs for 2013	[redacted]	269,875	[redacted]
Difference	[redacted]	478,925	[redacted]
Est. Replacement at Market	[redacted]	478,925	[redacted]
Est. Over Recover	[redacted]		

Given that actual market prices during 2013 were well below the contract prices, as estimated in Table 2 above, PCA Period 12 power costs declined as the PPA generation was replaced with market purchases at a lower market power price beginning April 1, 2013.

While higher Mid-C hydro generation (due to 107 percent of normal runoff for January through July - see Exhibit No. ___(DEM-9)) was also a benefit, it was offset by the decline in hydro generation the last two months of 2013 as stream flows fell to less than 80 percent of normal.

Q. Please provide a summary of how the power resources used to serve load compare to those set in rates for PCA Period 12.

A. Table 3 provides an itemization of the changes in generation and retail loads from those included in the baseline rate for PCA Period 12. Please note that during PCA Period 12, PSE deferred the costs and benefits associated with the generation for PSE's newly acquired Ferndale facility and the renovated Snoqualmie Falls Project – both of which are discussed in detail in Ms. Katherine J. Barnard's Exhibit No. ___(KJB-1T).

Table 3: 2013 Generation and Load Differences from Rates		
	Change	Change
Generation Higher / (Lower) than Rates (in aMW's):	aMW	%
Hydro	(1)	-0.2%
Hydro - Snoqualmie On-line Benefit Deferred	5	100.0%
Colstrip	(54)	-9.8%
Gas Fired	19	3.6%
Ferndale - New Resource with Costs Deferred	77	100.0%
Wind	(20)	-8.1%
Contracts	(61)	-32.5%
Market Purchases and Sales	5	0.9%
Load (Generated, Purchased & Interchanged)	(30)	-1.1%
Delivered Load	(33)	-1.3%

Q. Please provide a summary of the power cost variances for PCA Period 12 compared to those set in rates.

A. Table 4 provides a summary of the items which caused the calculated $37.8 million over recovery of power costs for PCA Period 12.

Table 4: Components of CY 2013 PCA Over Recovery ($ in millions)			
Over / (Under) Recovery - Actuals vs Rates:	11 GRC Jan-Oct	13 PCORC Nov-Dec	CY 2013
Delivered Load Lower by 287,103 MWh	($17.5)	($0.3)	($17.8)
Load (GPI) Lower by 264,368 MWh	6.9	(0.8)	6.1
Lower Gas Fired gen. replaced with Lower Priced Power	29.1	(4.8)	24.2
Coal generation and costs	1.1	(1.8)	(0.7)
Hydro generation shape & Snoqualmie deferral	0.3	(2.4)	(2.2)
Wind generation lower	(2.5)	0.0	(2.4)
Lower Mid-C Costs	4.6	1.7	6.3
Transmission Revenues	3.5	0.7	4.2
Long-term contracts	19.2	0.1	19.3
Other - Transmission revenues, etc.	10.9	(10.1)	0.8
2013 PCA Over Recovery of Power Costs	**$55.6**	**($17.8)**	**$37.8**

Q. Are PSE's PCA Period 12 actual allowable power costs net of any accounting adjustments?

A. Yes, there were three adjustments made to credit, or reduce, the power costs by a total of $1.2 million during PCA Period 12. These adjustments are noted below and are also discussed in greater detail in Ms. Katherine J. Barnard's Exhibit No. ___(KJB-1T):

1. A debit of $0.7 million was applied to the allowed PCA Period 12 power costs to add back the net costs of the 2012 Cedar Hills gas sales activity from the PCA that were removed in PCA Period 11. This represents the cost of the physical gas sold offset by the revenue from the sale of the gas commodity as well as any inventory write-downs to the lower of cost or market;
2. A debit of $0.4 million was added back to PCA Period 12 power costs to reflect the portion of 2012 and 2013 transmission revenues that were refunded back to customers, and;
3. A debit of $0.1 million was applied to the allowed PCA Period 12 power costs to remove the reversal of the gas for power inventory write-down to the lower of cost or market .

IV. ENVIRONMENTAL ATTRIBUTES

Q. What are environmental attributes?

A. An environmental attribute is an instrument used to represent the environmental benefit - or the incremental value - of renewable energy associated with an energy product which has an identifiable value that is separate from the physical commodity.

Q. Please provide a brief discussion of PSE's environmental attributes for biogas.

A. In February 2011, PSE entered into an agreement with the King County Solid Waste division of King County, Washington ("King County") to purchase all of the

emission credits associated with the pipeline quality gas produced by the Cedar Hills Regional Landfill facility ("Cedar Hills"). In exchange, King County receives a share of the net proceeds from the sale of qualified renewable gas or renewable energy credits produced by the Cedar Hills gas if it is used to generate electricity. This agreement, combined with the agreement to purchase the pipeline quality gas from Bio Energy (Washington), LLC ("Bio Energy"), entitles PSE to all the renewable attributes associated with the landfill gas generated by Cedar Hills. Obtaining the environmental attributes of the Cedar Hills pipeline quality natural gas created a renewable resource - biogas ("Cedar Hills biogas") - and enabled PSE to begin monetizing the environmental attributes. The environmental attributes of biogas are a marketable commodity – separate from the underlying physical fuel – and may be used to demonstrate renewable resource compliance with various state and federal programs, corporate environmental commitments, Environmental Protection Agency's Renewable Fuel, etc.

Q. How does PSE account for the pipeline quality gas generated by Cedar Hills?

A. In October 2008, PSE arranged to purchase all of the pipeline quality gas supply produced from Cedar Hills under a separate agreement with Bio Energy. Prior to the February 11, 2011 agreement with King County, the cost of the Cedar Hills landfill gas was a fuel expense. Beginning on February 11, 2011, and through October 31, 2013, PSE had the ability to monetize the renewable attributes of the landfill gas and PSE tracked the Cedar Hills biogas in a separate gas inventory account. When this biogas was sold, PSE separately accounted for the sale of the

physical gas as a sale of excess gas by crediting FERC account 456, other electric revenues, with the sale price at market of the physical biogas sold and debiting FERC account 456 with the cost of the underlying physical gas. The revenues generated from the sale of the environmental attributes of the Cedar Hills biogas were tracked separately and deferred in the "Deferred Revenue – Non-core Gas Green Attributes" account 25301141 for future customer credit. Incremental costs related to the sale, such as payments to King County for their share of the net proceeds, reduced the deferred biogas revenues to be returned to PSE customers.

Q. Were there any changes in how PSE accounts for the pipeline quality gas generated by Cedar Hills during PCA Period 12?

A Yes. PSE received permission, per PSE's accounting petition for the deferral of the net proceeds from the sale of biogas and environmental attributes, Docket No. UE-131276, to include the net proceeds from the sale of environmental attributes associated with biogas through October 31, 2013 in its Schedule 137 Renewable Energy Credit Tracker for return to ratepayers. In addition, all revenues and expenses associated with biogas subsequent to October 31, 2013 are to be accounted for as below-the-line items.

V. CONCLUSION

Q. Do you believe that PSE has met the Commission's prudence standard with respect to its power costs during PCA Period 12?

A. Yes; PSE met the Commission's prudence standard for the PCA Period 12 power costs because PSE's management of its power costs during PCA Period 12 was

reasonable. PSE has structures and processes in place to formulate strategies for controlling power costs and executed those strategies, taking into account information and variables associated with managing a complex resource portfolio within a dynamic market environment.

Q. Does that conclude your testimony?

A. Yes, it does.