EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-13____
PCA 11 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 2013 Power wCost Adjustment Mechanism Report**	**Docket No. UE-13____**

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

REDACTED VERSION

MARCH 29, 2013

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, Structuring & Asset Optimization 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. Then I discuss PSE's Environmental Attributes transactions for the period that began on January 1, 2012 and ended on December 31, 2012 ("PCA Period 11"). 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 PCA Period 11. Finally, I compare PSE's actual power costs for PCA Period 11 to its baseline power cost rates that were in effect for PCA Period 11. See the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for further information regarding the PCA baseline rates for the PCA Period 11. Through May 13, 2012, the approved baseline power cost rate was the one established in Docket No. UE-112050. This approved baseline power cost rate was essentially equal to the baseline power cost rate approved in PSE's 2009 general rate case ("GRC") under Docket No. UE-090704 except that it excluded the portion of that baseline power cost rate related to the recovery of the Tenaska Regulatory Asset under Schedule 133. The Tenaska Regulatory Asset was fully amortized in December of 2011, and thus Schedule 133 was set to zero effective January 1, 2012 and the baseline power cost rate was adjusted accordingly in Docket No. UE-112050.

The baseline power cost rate from PSE's 2011 GRC, WUTC Docket No. UE-111048 has been in effect since May 14, 2012.

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 Docket Nos. UE-011570 and UG-011571. 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 five 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 11, PSE's actual power costs were $25.6 million below the amounts recovered through the power cost baseline rate. PCA Period 11 actual power costs are discussed in more detail in section IV.C of my testimony. See the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for further information and discussion of the PCA Annual Report for PCA Period 11.

Through May 13, 2012, the approved baseline power cost rate was the one established in Docket No. UE-112050. This approved baseline power cost rate was essentially equal to the baseline power cost rate approved in the 2009 GRC, except that it excluded the portion of that baseline power cost rate related to the recovery of the Tenaska Regulatory Asset under Schedule 133. The Tenaska Regulatory

Asset was fully amortized in December of 2011, and thus Schedule 133 was set to zero effective January 1, 2012 and the baseline power cost rate was adjusted accordingly in Docket No. UE-112050.

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 11?

A. Yes. PSE's fifty month purchased power agreement with Iberdrola Renewables for 100MW of winter capacity and energy associated with the Klamath Peaker ("Klamath PPA") was deemed prudent in PSE's 2011 GRC, however, the Klamath PPA started January 1, 2012, before the effective date of the 2011 GRC rates on May 14, 2012 and so the actual costs of the Klamath PPA prior to May 14, 2012 were subject to the limitations under the PCA Exhibit G calculation. See the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for

further information and discussion of the Exhibit G calculation that reduced allowed power costs $1.4 million for PCA Period 11.

III. 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.

A. Renewable Energy Credits

Q. What is a Renewable Energy Credit?

A. A Renewable Energy Credit ("REC") represents the environmental attributes of renewable energy generation in the form of a marketable commodity. PSE receives RECs from its owned and contracted renewable energy resources such as PSE's owned Hopkins Ridge, Wild Horse and Lower Snake River Phase 1 ("LSR Phase 1") wind projects, as well as its contracted portion of the Klondike III wind project under a Power Purchase Agreement ("PPA") with Iberdrola Renewables. Generally, RECs may be traded as a "bundled" product where the electricity and environmental attributes are sold together or as an "unbundled", or REC-only, product where only the environmental attributes are sold.

Q. Did PSE have any REC transactions during the PCA Period 11?

A. Yes. In 2009, PSE entered into contracts with third-parties for the sale of its surplus

RECs (*e.g.*, in excess of PSE's near-term renewable targets). These REC sales were bundled with electricity and sourced from PSE's portfolio of renewable resources. During 2012, PSE delivered a portion of these bundled RECs to the third-parties it contracted with in 2009. In addition, PSE transacted with third parties to sell excess unbundled RECS. PSE's accounting for the revenues created by the sale of RECs was determined in PSE's Docket UE-070725 and was modified in PSE's 2011 general rate case Docket UE-111048, both of which were applicable during the PCA Period 11 period.

B. Biogas

Q. Please provide a brief discussion of PSE's 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 RECs produced by the Cedar Hills gas when 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. PSE has entered into short-term agreements with third-parties for the sale of the Cedar Hills biogas and is also evaluating other options for this product through discussions with third-parties for both short- and long-term arrangements.

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, 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 is sold, PSE accounts 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 are 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, reduce the deferred biogas revenues. As noted

below, these costs were not included in the determination of the PCA Period 11 $25.6 million power cost variance because they were deferred in FERC account 253.

IV. PCA PERIOD 11 POWER COSTS

A. PCA Period 11 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 11?

A. As noted above, the baseline rates in effect during the PCA Period 11 reflect the power portfolio from PSE's 2009 GRC through May 13, 2012 and from PSE's 2011 GRC beginning May 14, 2012. There were a number of changes to PSE's portfolio that were reflected in the PCA Period 11 power costs that were different than those recovered in rates for the entire PCA Period 11. Specifically, PCA Period 11 actual power costs included:

(1) Energy from newly acquired resources which were included in the baseline rate effective May 14, 2012 as they were deemed prudent in PSE's 2011 GRC:

a. The LSR Phase 1 wind facility provided 342.7 MW of additional capacity beginning February 29, 2012. Costs for this resource were not subject to an adjustment under Exhibit G as is discussed in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T); and

b. The 100MW of winter capacity and energy associated with the Klamath Peaker's PPA for the term January 1, 2012 through February 29, 2016. As discussed above, costs for this resource were subject to an adjustment under Exhibit G;

(2) Energy from the 4-year winter on-peak PPA with Barclays Bank PLC for 75 MW of winter-only capacity effective November 1, 2011 which was deemed prudent in PSE's 2009 GRC but was not included in PSE's 2009 GRC baseline rate

effective April 8, 2010 as the contract began after the rate year ended;

(3) Zero generation from PSE's Snoqualmie Falls Hydroelectric Project due to the redevelopment of Powerhouse #1 (12 MW capacity) and Powerhouse #2 (34 MW capacity) for the entire PCA Period 11 period as compared to three months of generation (55,681 MWhs) included in the 2009 GRC baseline rate;

(4) The new twenty-year Mid-C contract with the Public Utility District No. 1 of Chelan County, Washington ("Chelan PUD") 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 Rock Island Hydroelectric Project ("Rocky Reach") 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 reduced PSE's capacity to 156 MW (as compared to the previous contracted 312 MW). The contract share reduction from 38.9 percent to 25 percent for the Rocky Reach Hydroelectric Project was effective November 1, 2011. These share reductions were not included in PSE's 2009 GRC baseline rate as they occurred after the rate year ended;

(5) A change in the share of net 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 2009 GRC (1.29 percent and 0.64 percent in 2010 and 2011, respectively), to 0.90 percent of the combined Priest Rapids Hydroelectric Project projection for the PCA Period 11 period;

(6) Contracts executed or extended under PSE's Schedule 91 tariff;

a. a PPA with Edaleen Cow Power, LLC for the output of an anaerobic manure digester (0.75 MW of additional capacity);

b. a PPA with CC Solar #1, LLC for the output of a solar photovoltaic system with a capacity of 0.01287 MW;

c. a PPA with CC Solar #2, LLC for the output of a solar photovoltaic system with a capacity of 0.01287 MW;

d. a PPA with Lake Washington School District for the output of a solar photovoltaic array with a capacity of 0.355 MW;

e. a PPA with Bio Energy (Washington) LLC for the output of a landfill gas generator with a capacity of 4.88 MW;

f. a PPA with Rainier Biogas LLC for the output of a mixed plug-flow anaerobic manure digester with a capacity of 1.0 MW; and

g. a PPA with Swauk Wind, LLC for the output of 5 Gamesa wind turbines with a combined capacity of 4.25 MW;

(7) The acquisition of the 270 MW Ferndale Generating Station ("Ferndale"), a combined cycle natural gas-fired power plant, from Tenaska Washington Partners, L.P. on November 15, 2012. Costs for this resource were not subject to an adjustment under Exhibit G as is discussed in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T);

(8) The expiration of:

a. the 4-year winter 150 MW on-peak power purchase agreement with [redacted] on February 29, 2012;

b. PSE's 245 MW capacity contract with Tenaska Washington Partners, LP which expired on December 31, 2011;

c. PSE's 145 MW capacity contract with March Point Cogeneration Company expired December 31, 2011;

d. PSE's 22.9 MW capacity Municipal Steam Waste contract with the City of Spokane expired December 31, 2011; and

e. PSE's agreement with Occidental Energy Marketing, Inc. for gas transportation between the Rockies region and Sumas through June 30, 2011;

(9) New long-term gas for power pipeline capacity for:

a. 25,000 MMBtu per day of gas for power pipeline capacity from Sumas to Jackson Prairie and Longview effective October 1, 2011;

b. 29,489 MMBtu per day of Westcoast pipeline deliverability between Station 2 and Huntingdon (Sumas) effective December 1, 2012 through November 30, 2017;

c. 3,644 MMBtu per day of Westcoast pipeline enhanced

capacity from Station 2 with deliverability to either Huntingdon (Sumas) or Kingsgate effective December 1, 2012 through November 30, 2017. The enhanced deliverability at Kingsgate ends October 31, 2014; and

d. 52,000 MMBtu per day of gas distribution transportation with Cascade Natural Gas Corporation to deliver natural gas to the newly acquired Ferndale plant effective November 15, 2012 through September 30, 2037; and

(10) 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 11 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 11 by describing actual hedging strategy decisions and their execution undertaken by PSE with respect to its power supply for a sample month, April 2012. *See* Exhibit No. ___(DEM-3C).

B. PSE's Management of its Power Portfolio and Related Fuel Supply for PCA Period 11

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 11, PSE's Energy Portfolio Management function ("EPM department") included certain employees from the Energy Supply & Planning

department ("ESPD") and the Structuring, Asset Optimization and Analytics department. The EPM department is composed of energy market analysts, quantitative analysts, seasoned energy traders and other professionals. The EPM department is responsible for identifying, quantifying, monitoring and recommending risk management strategies for PSE. The EPM department performs these tasks and manages PSE's short- and medium-term portfolios. During PCA Period 11, the ESPD was led by the Senior Vice President, Energy Operations. The Structuring, Asset Optimization and Analytics department was led by the Vice President Finance and Treasurer.

The Energy Risk Control ("ERC") department includes the Credit Risk Management group, and is responsible for providing risk control oversight. The ERC department is led by the Vice President Finance and Treasurer.

PSE's Energy Management Committee ("EMC") – composed of five senior PSE officers – oversees the activities performed by the EPM 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] became the Programmatically Managed Hedge in accordance with the EMC approved strategy. EPM 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, April 2012. 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 11, 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 EPM 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 economic 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 EPM department evaluates and develops risk management strategy proposals and/or executes transactions around the purchase or sale of gas or power, as appropriate, to 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. EPM 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. EPM department staff also determines when and how to execute such transactions to maintain each months net exposure reduction within the maximum and minimum limits.

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

A. The EPM 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 EPM 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 EPM 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.

EPM 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 though a speaker system, and other tools. The EPM 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 EPM 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 also uses a counterparty credit risk management system to assist the

Credit Risk Management group and the EPM department staff in evaluating credit issues associated with potential transactions with respect to credit issues. With this tool, staff can review data including:

- Moody's and S&P rating of the entity;
- applicable information about the parent of the entity;
- amount of parent guarantee credit provided to PSE, if applicable;
- the entity's amounts payable and receivable;
- the aggregate mark to market exposure of all open forward transactions with the entity (the dollar value of the difference between the original contract price and current market price);
- the credit limit assigned to the entity;
- the existence of netting terms; and
- Accounting Standards Codification 815 designations for accounting purposes.

This information is gathered and calculated daily.

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, in order to capture lower as well as higher prices during periods of volatility) 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

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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 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.

EPM 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 11 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 11 power supply and costs?

A. Yes. Take, for example, PSE's energy requirements for April 2012. Beginning in [redacted], the power supply for April 2010 rolled into staff's 23-month Programmatically Managed Hedge purview. PSE's EPM staff began to actively reduce spot market price exposure for the delivery period April 2012. From [redacted] through [redacted], on a monthly or bi-monthly basis, EPM department staff

developed strategies to reduce PSE's exposure with respect to its electric supply needs for April 2012. 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. EPM department staff can make recommendations to depart from this plan, but execution of such hedges is subject to EMC approval. With respect to the April 2012 power supply, EPM 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 April 2012, which are presented in Exhibit Nos. ___(DEM-7C) and ___(DEM-8C).

Beginning in [redacted], the power supply for April 2012 rolled into staff's [redacted] Programmatically Managed Hedge purview. Beginning in [redacted], the power supply for April 2012 rolled into staff's Actively Managed Hedge - at which point staff continued to analyze PSE's position for April 2012 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 11?

A. No. Similar activities were undertaken with respect to managing PSE's portfolio and exposure for the entire PCA Period 11.

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 2012?

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 the effectiveness of entering into various call options that were available in the market 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 11 Actual Power Costs

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

A. During PCA Period 11, PSE's rates have over-recovered actual power costs by $25.6 million. As a result of the PCA sharing bands, PSE customers will share $2.8 million of this over-recovery and PSE will retain the remaining $22.8 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 volatilities, 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; 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

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

employing:

(i) a 70-year hydro data set to determine hydro generation[2];

(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 11 between PSE's actual power costs and power costs recovered in rates?

A. PSE's $25.6 million over-recovery of amounts recovered through the Power Cost Baseline Rate during the PCA Period 11 was primarily due to lower power costs than what was embedded in PSE's 2009 GRC baseline rate through May 13, 2012. The key drivers behind this reduction in power costs compared to the 2009 GRC were: i) lower power and gas market prices; and ii) replacing power from PPA's with Tenaska Washington Partners ("Tenaska"), March Point Cogeneration ("March Point") and City of Spokane Municipal Steam Waste ("Spokane")[3] with lower priced market purchases. During PSE's 2011 GRC, the aforementioned drivers were also main contributors to the $157.9 million or 16% decline in baseline rate power costs from those set in PSE's 2009 GRC.

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[2] PSE requested to use an average of 70-years Mid-C streamflow history in its 2011 general rate case, Docket No. UE-111048.

[3] Tenaska, March Point and Spokane PPAs all expired December 31, 2011.

Actual power and gas market prices in 2012 were well below prices included in the 2009 GRC baseline rate. These reduced power and gas prices resulted in a decrease to the actual average cost of market power purchases and weighted average cost of gas compared to the costs in rates. While market prices alone do not consider the impact of the fixed price contracts, for purposes of comparison, Table 1 presents a comparison between average market prices during calendar year 2012 to the average prices embedded in the 2009 GRC baseline rate and the 2011 GRC baseline rate.

Table 1: Power and Gas Prices

Average Power and Gas Price Comparison
Calendar Year 2012 Compared to Prices in Rates

	Mid-C Flat	Sumas
2012 Actual - Average Calendar Year	$16.69	$2.69
2009 GRC Baseline Rate - Average Rate Year	$42.49	$5.97
2011 GRC Baseline Rate - Average Rate Year	$25.76	$2.90

PSE's 2009 GRC power costs included energy and capacity costs associated with PPA's for 245 MW of capacity with Tenaska, 145 MW of capacity with March Point and 22.9 MW of capacity with Spokane. The table below reflects the cost (both fixed capacity charge and power price) and generation associated with each PPA as included in the 2009 GRC baseline rate that was in effect through May 13, 2012.

PPA Cost and Generation
Embedded in PSE's 2009 GRC Baseline Rate

	Cost	MWh	$/MWh
Tenaska	$94,618,348	567,136	$166.84
March Point	$68,314,044	1,065,643	$64.11
Spokane	$12,882,497	142,466	$90.43

Given that actual market prices during 2012 were well below the contract prices, PCA Period 11 power costs declined as the PPA generation was replaced with market purchases at a lower market power price beginning January 1, 2012.

While higher Mid-C hydro generation (due to 128 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 due to the reduction of PSE's share of the output from the Rocky Reach hydroelectric project. On November 1, 2011, PSE's share of Rocky Reach declined from 38.9% to 25% due to the beginning of the new contract with Public Utility District No. 1 of Chelan County. This decline in Mid-C hydro capacity of about 178 MW was not included in the 2009 GRC Baseline Rate as it was outside of the rate year.

Q. Are PSE's PCA Period 11 actual allowable power costs net of any accounting adjustments?

A. Yes, there were two adjustments made to credit, or reduce, the power costs by a total of $0.8 million during PCA Period 11. These adjustments are noted below and are also discussed in greater detail in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T):

1. A credit of $0.7 million was applied to the allowed PCA Period 11 power

costs to remove the net costs of the Cedar Hills gas sales activity from the PCA. This credit includes 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. As discussed above, the revenues associated with the environmental attribute of the Cedar Hills gas were deferred separately and are not part of actual power costs.

2. A credit of $0.1 million was applied to the allowed PCA Period 11 power costs to remove the gas for power inventory write-down to the lower of cost or market.

Q. Are there any other entries included in PCA Period 11 power costs that were not subject to the PCA Mechanism true up methodology that you would like to discuss.

A. Yes. PCA Period 11 power costs removed the amortization of $0.94 million resulting from an under recovery of the costs associated with the Tenaska regulatory asset that were moved out of base rates in the 2009 GRC and put into a separate tariff rider, Electric Tariff Schedule 133. The under collected balance was collected and amortized outside of the PCA Mechanism during calendar year 2012 pursuant to WUTC Docket No. UE-120137. In addition, the entry reducing power costs by $0.94 million during PCA Period 10 was reversed in PCA Period 11 power costs. This adjustment wholly offsets the removal of amortization discussed above for a net zero impact on PCA Period 11. Additional discussion of this item is included in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T).

V. CONCLUSION

Q. Do you believe that PSE has met the Commission's prudence standard with respect to its power costs during PCA Period 11?

A. Yes; PSE met the Commission's prudence standard for the PCA Period 11 power costs because PSE's management of its power costs during PCA Period 11 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.