EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. _____
2005 PCA 3 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 2005 Power Cost Adjustment Mechanism Report**	**Docket No. UE-_____**

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

REDACTED VERSION

AUGUST 31, 2005

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF DAVID E. MILLS

I. INTRODUCTION

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

A. My name is David E. Mills. My business address is 10885 N.E. Fourth Street, Bellevue, Washington, 98004-5591. I am the Director, Power & Gas Supply Operations for Puget Sound Energy, Inc. ("PSE" or "the Company").

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 Director, Power & Gas Supply Operations for PSE?

A. I am responsible for the Company's Power Supply Operations and Gas Supply Operations Departments. In this capacity, my responsibility area manages all PSE short-term and medium-term wholesale power and natural gas portfolios (up to two years), and my area works with Mr. Eric Markell's responsibility area to plan for long-term hedging requirements. Mr. Markell is the Senior Vice President Energy Resources for PSE.

Q. Please summarize the contents of your testimony.

A. I first provide some brief background information regarding the PCA Mechanism and how it addresses the volatility of PSE's power costs. I then describe the efforts undertaken by PSE to attempt to control and moderate its power costs during the one-year period that began on July 1, 2004 and ended on June 30, 2005 ("PCA Period 3"). Finally, I provide a high-level overview of the Company's actual power costs for PCA Period 3 as compared to its baseline power cost rate.

II. BACKGROUND REGARDING THE PCA MECHANISM

Q. Why does the Company have a PCA Mechanism?

A. The parties to the Company's 2001 general rate case were keenly aware from the experience of the Western Power Crisis in 2000-01 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 Power Cost Adjustment Collaborative in the 2000-01 rate case agreed to a negotiated Power Cost Adjustment ("PCA") Mechanism. The Commission approved the PCA Mechanism in its Twelfth Supplemental Order, Docket Nos. UE-011570 and UG-011571 (June 20, 2002) at 11-15.

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 volume and price drivers of power cost volatility are: (1) streamflow variation affecting the supply of hydroelectric generation; (2) risk of forced outages of generating units; (3) weather uncertainty affecting power usage; (4) variations in market conditions such as wholesale gas and electric prices; and (5) transmission and transportation constraints. All of these create load/resource volatility which PSE balances with wholesale market purchases and sales, causing fluctuations in power costs.

Q. How does the PCA Mechanism work?

A. Generally, the PCA Mechanism sets forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels (so-called "bands") of power cost variances for the first $120 million of power cost variances, with a $40 million cap on PSE's potential exposure over a 4-year period ending June 30, 2006. On power cost variances over the $40 million cap, the PCA sharing mechanism allocates 99% of costs or benefits to customers and the remaining 1% of costs or benefits to PSE.

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

A. Power cost variances are the difference between: (i) the "baseline" power costs that are built into PSE's electric rates during a particular rate case based on projections of fixed and variable power costs that are anticipated to be incurred during an annual period, and (ii) the variable power costs that PSE actually incurs during that period, plus the fixed power costs as determined in the most recent

rate proceeding.

The PCA Mechanism requires an annual true-up of PSE's actual power costs (in contrast to the projected power costs that are generally included in rates) and an accounting of the amount in the deferral account that tracks excess costs or benefits. *See* Order No. 04 in Docket No. UE-031389 (Jan. 14, 2004), in which the Commission approved PSE's 2003 PCA Annual Report regarding the true-up for the PCA Period 1.

Q. How does the PCA Mechanism treat PSE's costs related to new resources brought into the Company's power portfolio?

A. Under the PCA Mechanism, new resources with a term of less than or equal to two years are included in allowable PCA costs, with the prudence of such resources determined in the Commission's review of the annual PCA true-up. Some costs related to a new electric resource with a term of greater than two years are included in the PCA allowable costs through a bridge mechanism until the total costs of such resources can be reviewed and approved in a power cost only or general rate case.

III. PCA PERIOD 3 POWER COSTS

A. New Resources During PCA Period 3

Q. Is the Company seeking inclusion of any new long-term electric supply resources in the PCA Period 3 power costs?

A. No. The Company has acquired the Hopkins Ridge wind generating facility, but that facility is currently under construction and does not impact PCA Period 3 power costs. The Company is seeking recovery of Hopkins Ridge Project costs on a going forward basis as of December 1, 2005, through PSE's 2005 PCORC proceeding, Docket No. UE-050870.

Q. Did PSE acquire any new resources during PCA Period 3 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/or fuel to generate power. The majority of such transactions during this period were short-term (less than 3 months) balancing transactions of power and natural gas purchase and sale contracts. Such balancing transactions are made in response to changes in market heat rates, which guide decisions whether to hedge power versus natural gas, and changes in load or resource availability. Such transactions include intermediate term transactions entered into pursuant to PSE's programmatic portfolio hedging efforts.

The Company also purchased winter capacity and entered into power exchanges to improve the reliability of supply to PSE's system.

The Company also entered into a two-year power purchase agreement with the Arizona Public Service Company that impacts PCA Period 3 power costs because delivery under the agreement commenced during PCA Period 3.

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 help ensure that PSE can: (1) deliver reliable energy when our customers demand it; (2) serve our customers at a low cost while mitigating price volatility; and (3) enhance the value of PSE's energy resources to reduce power and gas costs.

The Company has organizational structures in place to provide upper level oversight and policy direction and decisions while also permitting power supply operations and energy risk management staff the flexibility to implement PSE's policies and manage the portfolio on a day to day basis. The Company has also developed systems and tools to aid its personnel in performing their portfolio management duties. The Company is continually looking for ways to improve our existing systems and tools to further enhance our risk management capabilities.

The following section of my testimony first describes these systems and tools generally. I then illustrate their application for PCA Period 3 by describing actual hedging strategy decisions and their execution undertaken by PSE with respect to its power supply for May 2005. I also provide additional information below regarding the Company's analysis of winter peaking contracts and exchanges and the Arizona Publix Service Company Agreement.

B. PSE's Management of its Power Portfolio and Related Fuel Supply for PCA Period 3

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. PSE's Energy Risk Management Department ("ERM Department") – composed of energy market analysts, quantitative analysts, and other professionals – is responsible for identifying, quantifying, and reporting on risk factors. The ERM Department also develops and recommends risk management strategies for the Company. The ERM Department works closely with the Power Supply Operations ("PSO") and Gas Supply Operations Departments to perform these tasks and to manage PSE's short-term portfolios.

PSE's Risk Management Committee ("RMC") – composed of senior PSE officers – oversees the activities performed by the ERM Department and PSO

staff. The RMC provides policy-level and strategic direction on a regular basis. In addition, the RMC reviews bi-weekly position reports, sets risk exposure limits, approves policy and procedures, reviews proposed risk management strategies, and approves the appropriate strategies for implementation by staff.

With respect to hedging strategies for specific time periods or quantities of energy, the RMC has approved a programmatic hedging plan. PSO staff follows this plan to systematically reduce the Company's net power portfolio exposure beginning 18 months 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. Such exposure reduction is subject to minimum and maximum monthly limits to reduce timing and market risks associated with hedging activities. PSO staff may also recommend hedging six or more months out that departs from this plan, but execution of such hedges is subject to RMC approval.

By [redacted] ahead of delivery, the bulk of the hedging strategies and transactions have been made. Decisions about hedges for delivery five months or less after execution ("Balance of the Month plus 5" or "BOM+5") are made by PSO staff, within limits set out in PSE's Energy Supply Hedging and Optimization Procedures Manual.

Q. How does PSE integrate hedging activities into its provision of electric power to customers?

A. PSE employs production cost modeling techniques to estimate future demand for on-peak power, off-peak power, and gas for PSE's fleet of natural gas-fired power plants through its KW3000 system. The KW3000 system permits PSE to model scenarios of price, hydro, load, generating resources and other inputs as required to represent future projected portfolio needs.

Q. Please further describe what KW3000 does.

A. In order to model a variety of scenarios regarding PSE's gas-fired generation, KW3000 takes into account each plant's individual operating characteristics which include conversion efficiency, start-up costs, variable operating costs, ramp rates, minimum run times, planned outages, availability, etc. KW3000 performs simulations of different market conditions and random outages in order to develop an estimate of how much gas is required and how much power will be produced. 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.

KW3000 incorporates the inter-relationship between gas and power prices in developing its probabilistic gas and power positions. In different market scenarios, PSE would have different gas or power requirements. The reason for this is twofold. First, the plants have different 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 often, and the price relationship between power and gas, "implied market heat rate," changes 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 the market conditions change, then PSE will expect to adjust its gas purchases and power purchases in order to serve load with the most economic resource. For example, it may be more economic to purchase power than to purchase gas to generate the power PSE needs to serve its load. KW3000 also incorporates information about hedges that PSE has already executed as part of PSE's resource stack.

Q. How does PSE use KW3000 to help make hedging decisions?

A. KW3000 generates a volumetric position report for gas for power, on-peak power, and off-peak power. The position report shows, for each of the twelve 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, Frederickson 1 (Fred 1), Tenaska and Encogen, Combustion Turbines (CT's), NUGs/QFs, Coal Plants, and Hydro (both PSE owned and Mid C Contracts). The gas-fired generation is therefore categorized by heat rate efficiency of the facilities. Tenaska and Encogen have very similar heat rates, and are grouped together. Fredonia, Fredrickson, and Whitehorn CTs are grouped together because of their similar heat rate conversions. Frederickson 1 is separate from the

others because of its lower heat rate.

Based on this volumetric position for each month, KW3000 also generates a report showing the potential exposure associated with the "open" positions (defined as any net surplus or deficit amount). *See* Exhibit No. ___(DEM-9C) at Tab 1.

Once PSE's aggregated energy position and net exposure are defined for a particular period, the risk management staff evaluates and develops risk management strategy proposals and/or executes transactions around the purchase or sale of gas or power, as appropriate to balance the position and reduce the exposure. Execution entails entering into specific transactions with approved counterparties, using both approved instruments and executed master agreements.

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

A. The ERM Department and PSO staff utilize a wide set of tools and sources of information to help them make informed decisions about dispatching plants, purchasing fuel, executing hedges approved by the RMC and optimizing excess capacity in the power portfolio. They also hold weekly strategy meetings so that the combined teams can review operational events, discuss market trends, and review new supply/demand information. With this context, they work together to understand the greatest exposures in the portfolio, and discuss where hedging

priorities occur.

The ERM Department and PSO team collect a wide range of data to monitor supply/demand factors which include but are not limited to: weather trends; macro economic factors; crude oil complex; gas storage inventories across the U.S., Canada and in the western U.S. specifically; hydro run-off forecasts; reservoir storage; precipitation and snowpack; and more. Additionally PSE staff review other energy companies' forecasts of price and supply/demand fundamentals, such as trading firm newsletters and consulting service forecasts.

The PSO staff also receive real-time information from a variety of sources which include email newsletters from industry publishers such as McGraw Hill (Gas Daily, Megawatt Daily), Bloomberg (live news and market data), Telerate, Intercontinental Exchange (live price data), broker lines that act as PA systems where current transactions are communicated though a speaker system, and other tools. The PSO group has live data coming from the systems operations staff so they can view real-time load data and real-time generation dispatch.

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

A. Yes. The Company also uses an on-line counterparty credit risk management system to assist the Credit department and the Power and Gas Supply Operations staff in evaluating potential transactions with respect to credit issues. With this tool, the reader can review data including: the Moody's and S&P rating of the entity; information about the parent of the entity is applicable; amount of parental

guarantee extended to PSE if applicable; the amounts payable and receivable with the entity; 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 existence of netting terms; FAS 149 designation for accounting purposes; and date that the information is calculated. The information is calculated daily.

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

A. Over the past several years, PSE moved from a more "discretionary" model of making hedging decisions to a more "programmatic" approach to hedging. PSE initially implemented a "dollar cost averaging" strategy, which has been described in several proceedings including the 2003 PCORC and the Company's annual filing for PCA Period 2, Docket No. UE-041570. The 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 frames, with the goal of purchasing a defined amount of power and of gas in order to ratably reduce the deficit positions by a small amount each month.

By Spring 2003, the RMC approved expansion of this concept to an "Exposure-based Dollar Cost Averaging." This refinement moved the Company 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 RMC would approve a dollar figure of risk to be reduced, and PSE staff would determine whether it was better to hedge gas or power. Also, as markets went up or down, the dollar amount would allow for greater or less volumetric purchases.

During PCA Period 2, the Company began to employ a metric called Margin at Risk ("MaR"), which measures risk reduction as a result of incremental hedging. *See* Exhibit No. ___(DEM-3C). 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, and provides an additional basis for choosing between available commodities. *See* Exhibit No. ___(DEM-9C) at Tab 2.

Q. Has the Company made any further adjustments to its overarching hedging strategies?

A. Yes. In July 2004, the RMC approved a continuation of a dollar cost averaging strategy informed by MaR. However, the RMC directed that PSE staff monitor and more actively address the exposure associated with PSE's power portfolio position eighteen months ahead of the time the power would be needed. Under this Rolling 12-Month Hedging Plan, PSO staff more actively manage the next rolling 12 months beyond their 6-month BOM+5 purview. This hedging plan

increased Staff's ability to react to position changes as a result of stream-flow variations, forced thermal plant outages and changing market conditions. *See* Exhibit No. ___(DEM-4C) at p. 1; Exhibit No. ___(DEM-5C).

Q. How does the Rolling 12-Month Hedging Plan work?

A. The plan is set up to systematically reduce the total net exposure for each month of the 12 months beyond the BOM+5 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 a month will fall within existing exposure limits when each month falls into the PSO staff's 6-month purview.

[redacted]

[redacted].

Additional illustration of the application [redacted] and PSE's other risk management tools and systems is provided in my Exhibit No. ___(DEM-9C).

Q. Has the Company addressed long-term hedging issues?

A. Yes. These efforts have taken place on a number of fronts, including through: analysis conducted for the Company's Least Cost Plan (filed with the Commission on May 2, 2005); building PSE's modeling capabilities; surveying customer preferences with respect to price volatility and hedging costs; assessing the amount of credit available to PSE to engage in longer-term hedging; and engaging in long-term market fundamental analysis.

Q. What is entailed in the modeling work?

A. PSE has been trying to capitalize on the strengths of two models: AURORA and KW3000. The Company is deploying both AURORA and KW3000 to run risk analysis using both gas and power forward market price inputs and to develop risk exposure metrics in the long-term portfolio similar to those that are already in place for the short-term portfolio. At the same time, the Company is trying to extend the KW 3000 model to incorporate a longer time horizon.

Q. What work has PSE done in the area of fundamental market analysis?

A. For the last several years, the industry as a whole has anticipated that the recent rise in natural gas prices would cause an increase in production and reduction of consumption, and that new LNG facilities and the delivery of Alaska and McKenzie Delta gas via pipeline projects would also reduce prices as soon as 2007-2008 and potentially until 2011. PSE has been investigating this "worldview" as part of its analysis regarding whether to seek to engage in longer-term hedging of gas supply. PSE has continued to gather a great deal of information from external sources about future market developments. PSE representatives have met with major oil companies, LNG analysts, banks, market forecasters and other industry observers as well as conducting independent research.

Q. Has PSE considered undertaking additional long-term hedging in the meantime?

A. Yes. As described in Mr. Markell's prefiled direct testimony in the 2005 PCORC proceeding, Docket No. UE-050870, the Company analyzed and entered into two long-term, fixed gas supply agreements in October 2004 to supply fuel for its gas-fired generating fleet from November 2005 through June 2008. These contracts effectively replace the 1993 CanWest contract that CanWest prematurely terminated effective in October 2005.

2. Application of PSE's Risk Management System to PCA Period 3 Power Costs

Q. Would you please provide some examples of how PSE applied the risk management systems, tools and strategies described above with respect to PCA Period 3 power supply and costs?

A. Yes, I would be pleased to. Take, for example, PSE's energy requirements for May 2005. As early as July 2003, PSE's short-term risk management team considered whether hedging transactions should be entered into to reduce potential spot market price risk during May 2005. Beginning in July 2004, PSE's short-term risk management team began to actively reduce potential spot market price risk during May 2005. From that time through November 2004, on a monthly or bi-monthly basis, the ERM Department and PSO staff developed strategies for reducing PSE's exposure with respect to its electric supply needs for May 2005. Such strategies were based on updated Position and Exposure Reports generated by KW3000, heat rate and market price information, and other information about market circumstances. PSE staff then executed these strategies through entering into hedging transactions to the extent such actions were within the limits pre-approved by the RMC in the Rolling 12 Month Hedging Plan. PSO staff retained the ability to propose actions outside of such limits to the RMC for its approval, although PSO staff did not make any such recommendations with respect to May 2005 power supply. Instead, PSO staff kept the RMC informed about its analyses and activities.

Beginning in December 2004, within the six-month window prior to delivery, primary responsibility for hedging PSE's May 2005 position shifted to PSE's ERM Department and PSO staff. They analyzed PSE's position for May 2005 on a monthly or bi-monthly 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 Energy Supply Hedging and Optimization Procedures Manual.

Describing and documenting the details of these activities requires extensive description and explanation of the information and reports used by the Company at each stage of its consideration, decisionmaking, and execution of PSE's risk management system. Thus, I have separated this description and documentation out for separate presentation in my Exhibit No. ___(DEM-9C).

Q. Are the activities described in Exhibit No. ___(DEM-9C) the only risk management activities that PSE undertook for PCA Period 3?

A. No, similar activities were undertaken with respect to managing PSE's portfolio and exposure for the entire PCA Period 3. Some of that information is evident from the materials presented in Exhibit No. ___(DEM-9C) and the other exhibits presented with my testimony. However, describing and documenting all of the details of such activities for the entire PCA Period 3 would be a monumental task.

Q. Did PSE undertake any measures other than the hedging activities described

above to manage its gas-fired generation fleet?

A. Yes. Due to prevailing and projected heat rates, the Company recognized that on a probabilistic basis it would not be operating its owned and contracted gas-fired generation at full capacity levels. The energy portfolio management team thus determined that it should terminate an ongoing inter-company supply arrangement between the gas portfolio and the power portfolio that was a legacy of the merger between Washington Natural Gas Company and Puget Sound Power & Light Company.

[redacted].

Q. Why did the Company decide that this arrangement should be terminated?

A. [redacted]

[redacted]. *See* Exhibit No. ___(DEM-4C) at p. 2; Exhibit No. ___(DEM-6C).

Q. How did the Company manage gas supply for Tenaska during PCA Period 3?

A. The Company managed gas supply for Tenaska as part of its overall power portfolio by applying the risk management tools and systems described above. The Company ultimately hedged [redacted].

3. Winter Peaking Contracts and Exchanges

Q. Why does PSE enter into winter peaking contracts?

A. Winter peaking contracts are procured so that PSE will be able to serve high loads

that occur during an extreme winter peak event. Daily call options contracted for November-February are a specialized hedge product and are one of the few products the Company can purchase in the market that can help cover price and volume risks associated with an extreme winter peaking event. The call options are structured on a "day-ahead" basis, and provide some disaster insurance for a multiple-day winter peaking event in a high priced market environment.

Q. Please explain more about call options.

A. Several types of call options are available. These include physical calls at Mid C, or other locations that allow the Company to call on physical power at a pre-determined price. Others are financial calls that provide a financial payment based upon the difference between posted market price at Mid C and the strike price (to off-set the costs of purchasing physical power). The financial payment acts as a hedge against the actual cost incurred to procure peaking supplies. Sometimes financial calls also have an associated temperature strike that must be met, along with a price strike.

Q. How else does PSE plan for winter peaking events?

A. In the power market, the preponderance of transactions relevant for PSE occur at the Mid C market. Therefore, during an extreme cold event, the Company makes incremental purchases [redacted] market if the prices are less than the cost of generating or if additional supplies are needed to supplement the Company's resources. [redacted]

[redacted]. Therefore, some precautions must be taken to augment the Company's electric portfolio to ensure deliveries of wholesale supply to the distribution system even during extreme cold winter events.

During an extreme cold event, there is a risk that no short-term firm capacity will be available. Additionally, curtailments of non-firm hourly transmission are likely to occur. Therefore, to ensure the Company has adequate transmission capacity to meet load demand, PSE has developed two strategies to deliver additional winter supply to its system. [redacted].

Q. What is an exchange transaction?

A. An example of an exchange transaction is where PSE will take delivery from a counterparty at a location where transmission constraints are not expected to occur, [redacted], and simultaneously provide supply to the counterparty at the Mid C in exchange.

Q. How did PSE approach the decisions whether and how to enter into winter peaking contracts and exchanges for the Winter of 2004-05?

A. PSE approached these decisions within the context of its portfolio and risk management systems and procedures, which are described in greater detail later in my testimony.

The Company specifically considered how it should plan for and execute contracts to provide peaking capacity or related hedges. As part of that analysis, PSE considered the cost-effectiveness of entering into various call options that were available in the market versus "self-insuring" against extreme winter peak events. The Company ultimately decided that it would purchase a limited quantity of winter peaking hedges. *See* "Update on Winter Peaking Capacity Purchases" dated October 14, 2004, Exhibit No. ___(DEM-7C).

The Company also analyzed transmission issues associated with potential extreme peaking and determined that it should enter into several exchanges and acquire additional BPA transmission rights for the winter of 2004-05. See "Winter 2004-2005 Transmission Assessment for Extreme Peak Planning" dated September 16, 2004, Exhibit No. ___(DEM-8C).

Q. How did the costs of the winter peaking and exchanges described above compare to the costs that were built into the Company's power cost baseline for PCA Period 3?

A. The baseline costs for the PCA Period 3 winter were established in Docket No. UE-031725, the Company's 2003 PCORC proceeding. These included a projection that PSE would incur $[redacted] in winter peaking contract and exchange costs during PCA Period 3. PSE's actual costs for winter peaking contracts and exchanges during PCA Period 3 totaled $[redacted].

4. The Arizona Public Service Purchased Power Agreement

Q. Please describe the agreement that the Company entered into with Arizona Public Service Company?

A. On June 3, 2004, PSE entered into a two year purchased power agreement ("PPA") for 85 MW of flat, firm energy from Arizona Public Service Company ("APS") beginning January 1, 2005 through December 31, 2006, at a price below the Dow Jones Mid-C index price.

Q. What is the background of the APS PPA?

A. The opportunity to enter into this PPA arose when APS submitted a proposed two-year PPA to the Company on March 12, 2004, in response to the Company's January 2004 All Source Request for Proposals (RFP). PSE's RFP evaluation process is described in the testimonies of Mr. Eric Markell and Mr. Roger Garratt in PSE's 2005 PCORC, Docket No. UE-050870 ("2005 PCORC").

The Company then compared the APS PPA to other potential short- to medium-term resource opportunities and ultimately determined that it should enter into the

agreement, as described in the testimony of Ms. Julia Ryan in PSE's 2005 PCORC.

Q. Was the APS PPA transaction investigated in PSE's 2005 PCORC proceeding?

A. Yes.

Q. Was there any resolution with respect to that transaction?

A. Ultimately, all parties to the 2005 PCORC entered into a Settlement Agreement that was filed with the Commission on August 30, 2005. The Settlement Agreement included the agreement of all parties that PSE's execution of the two-year APS PPA was prudent.

C. PSE's PCA Period 3 Power Costs

Q. How did PSE's actual power costs during PCA Period 3 compare to the power costs recovered in rates?

A. As detailed in the testimony of Mr. John Story, Exhibit No. ___(JHS-1T), and PSE's 2005 PCA Report, PSE's actual power costs exceeded the amounts recovered through the Power Cost Baseline Rate during PCA Period 3 by approximately $10.3 million.

The primary drivers of this under-recovery were: (1) higher per MWh power caused by, among other reasons, reduced hydro runoff for the past two water years

that was only 88% and 83% of normal above Grand Coulee; and (2) natural gas and power prices that were higher than assumed in the PCA Power Cost Baseline Rate. [redacted].

IV. CONCLUSION

Q. Do you believe that PSE has met the Commission's prudence standard with respect to its power costs during PCA Period 3?

A. Yes, I do. PSE's management of its power costs during PCA Period 3, including for the Tenaska generating facility, was reasonable. The Company 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 natural and market environment.

Q. Does that conclude your testimony?

A. Yes, it does.

[BA052410.030]