EXHIBIT NO. ___(JMR-1T)
DOCKET NO. UE-04____/UG-04____
2004 PSE GENERAL RATE CASE
WITNESS: JULIA M. RYAN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-04____** **Docket No. UG-04____**

PREFILED DIRECT TESTIMONY OF JULIA M. RYAN (NONCONFIDENTIAL) ON BEHALF OF PUGET SOUND ENERGY, INC.

APRIL 5, 2004

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF JULIA M. RYAN

I. INTRODUCTION

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

A. My name is Julia M. Ryan. My business address is 10885 N.E. Fourth Street, PSE 12N, Bellevue, Washington, 98004-5591. I am the Vice President of Risk Management and Strategic Planning for Puget Sound Energy, Inc. ("PSE" or "the Company"). From December 2001 to March 15, 2004, I served as Vice President Energy Portfolio Management for 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. ___(JMR-2).

Q. What are your duties as Vice President of Risk Management and Strategic Planning for PSE?

A. I lead the Company's Energy Risk Management, Power Supply Operations, and Gas Supply Operations Departments and Risk Analysis and Planning. In this capacity, my responsibility area manages all PSE short-term and medium-term wholesale power and natural gas portfolios (*i.e.*, up to two years), and my area

works with Mr. Eric Markell's responsibility area to plan for long-term hedging requirements. I also have responsibility for the corporate integrated financial and risk analysis and planning group.

Q. Please summarize the contents of your testimony.

A. I discuss significant challenges that PSE is facing with respect to its portfolio management, including volatility and risk in PSE's energy supply portfolios, credit concerns related to portfolio management, and the effect of PSE's current financial condition on PSE's ability to manage risks and costs associated with its portfolio. I also describe the approach taken by the Company in preparing its projection of normalized power costs presented in this case.

II. SIGNIFICANT ISSUES RELATED TO PSE'S ENERGY SUPPLY MANAGEMENT

Q. Why does the Company have an area dedicated to energy risk management?

A. PSE's resource portfolio is subject to significant volatility and risk that ultimately have a substantial impact on energy costs. In order to understand the challenges facing the Company and its management of this risk, it is important to understand the drivers of volatility and risk, as well as opportunities for, and limitations on, the Company's ability to manage such volatility and risk.

A. Volatility and Risk Drivers in PSE's Energy Supply Portfolios

1. Volumetric and Market Price Risks – Electric

Q. Please describe the drivers of volatility in PSE's power supply costs.

A. PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. Mr. Eric Markell describes PSE's power supply portfolio in his Exhibit No. ___(EMM-5). 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 thermal plants; (3) weather uncertainty affecting power usage; (4) variations in market conditions such as wholesale gas and electric prices; and (5) transmission and transportation constraints. As described in Exhibit No. ___(JMR-3), all of these create load/resource volatility which PSE balances with wholesale market purchases and sales, causing fluctuations in power costs that PSE seeks to mitigate through its energy risk management activities.

2. Volumetric and Market Price Risks--Gas

Q. Please describe the drivers of volatility in PSE's natural gas supply costs for its electric and gas portfolios.

A. The Company's gas supply portfolio is composed of a mix of supply contracts from various producing areas including the Western Canadian Sedimentary Basin, the Rocky Mountain area, and the San Juan Basin. Mr. Eric Markell describes

PSE's gas portfolio in Exhibit No. ___(EMM-5). The major volumetric and price drivers of gas cost volatility are load and temperature uncertainty and market prices.

The Company has significant price risk associated with the expected volume of its purchases and sales of natural gas in the wholesale markets due to volatility of the market price for gas at the various supply points. In addition, due to the high saturation of natural gas space heating in the Pacific Northwest, the level of the Company's retail natural gas demand is closely correlated to temperature. Variations in natural gas demand caused by temperature related load variation need to be addressed through gas storage and transactions in the wholesale gas markets.

3. Other Risk Factors – Electric and Gas

Q. Please describe other types of risk that PSE faces.

A. Examples of other risks include:

- counterparty risk is the risk of default by PSE's counterparties. A strategy to mitigate price volatility can go awry if the counterparty fails to perform its contractual obligations.
- execution risk is the ability to execute wholesale market transactions. Market liquidity, counterparty credit requirements and contractual requirements are examples of execution risk.

B. Addressing Energy Cost Volatility

1. Current Rate Mechanisms – Power and Gas Costs

Q. What regulatory mechanisms address volatility of gas costs?

A. Even before the deregulation of natural gas markets and unbundling of pipeline transportation and sales service began, escalation of Canadian gas prices in the mid-1970s prompted the Commission to put in place for the local distribution companies ("LDC's") under its jurisdiction Purchased Gas Adjustment (PGA) mechanisms. These PGA mechanisms allow actual gas costs to be passed through to retail rates through a periodic deferral accounting true-up. These mechanisms have remained in effect through the period of development of competitive gas markets and are in widespread use throughout the country to track wholesale gas price volatility.

Q. What is the Company's proposal for recovery of natural gas commodity costs in this case?

A. The Company proposes to continue the current PGA Mechanism.

Q. How was power price volatility dealt with in the resolution of the Company's 2001 general rate case?

A. In response to significant price 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 agreed to a

negotiated Power Cost Adjustment ("PCA") Mechanism. The PCA Mechanism set 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 on 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. 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. What has been PSE's experience with the PCA Mechanism since it was implemented?

A. PSE's power costs exceeded the amounts recovered through the Power Cost Baseline Rate during the first PCA period, the one-year period that began on July 1, 2002 and ended on June 30, 2003. The primary drivers of this under-recovery were: (1) decreased customer load; (2) higher per MWh power costs due to, among other reasons, reduced hydro (October 2002 through September 2003 runoff that was only 81% of normal above Grand Coulee); and (3) natural gas prices that were higher than assumed in the initial PCA Power Cost Baseline Rate. The market heat rates during the first PCA period were less than forecast in the PCA settlement, reducing the quantity of generation at PSE's gas-fired generation plants, which in turn reduced the level of secondary sales transactions

and increased the level of secondary purchase transactions that PSE made. *See generally* PSE's 2003 PCA Annual Report, Docket No. UE-031389 (filed August 28, 2003).

Q. Has PSE's under-recovery of its power costs continued?

A. Yes. The under-recovery continued during the second half of 2003 and the deferral reached the $40 million PCA cap in the fourth quarter of 2003.

Q. Do you expect this under-recovery to continue into 2004 and 2005?

A. Yes. Even though the PCA Power Cost Baseline Rate will be reset based on the power costs accepted by the Commission with respect to the rate year beginning April 2004 for the Power Cost Only Rate Case (PCORC) filing, Docket No. UE-031725, the Company is still at risk for power cost volatility from the PCA Power Cost Baseline Rate. For example, the PCA baseline rate for the PCORC filing assumes normal hydro generation based upon 40 years of natural streamflow data while the most recent hydro forecast for the current water year is closer to 90% of normal, causing a significant increase in power costs.

The new Power Cost Baseline Rate proposed in this filing would be set equal to a forecast of rate year power costs that the Company believes more equitably estimates the Company's likely rate year power costs than those used in the last rate case. However, the Power Cost Baseline is an estimate of normalized costs, and future power costs can be much higher or lower than even the best forecasts would indicate, due to the power cost volatility described above.

Q. Why does the Company believe that its proposed Power Cost Baseline Rate more equitably estimates the Company's power costs?

A. The Company is proposing to use 60-year hydro data in the development of the PCA baseline rate, as discussed later in my testimony. As the price associated with replacement of hydro generation is quite volatile, using the full number of years of hydro that is available provides a better measure of the future price.

Q. Is the Company proposing to change the PCA Mechanism?

A. No. The PCA risk-sharing mechanism continues to be a key element of PSE's efforts to manage the cost-effective energy resources that are necessary to meet the Company's load obligations and improve its financial integrity.

However, there are significant power cost risks that the Company cannot adequately hedge against. The most significant exposures are hydro energy variability, lower customer loads associated with variations from normal temperature, and fuel prices. Fuel prices are impacted by such things as global energy markets (*i.e.*, world crude oil prices and global LNG prospects) and regional market factors. Additionally, in the Pacific Northwest markets, fuel prices can be affected by hydro energy availability. Drier than normal hydro conditions can increase gas-fired generation demand. From the Company's perspective, a mechanism for power that is similar to the Purchased Gas Adjustment Mechanism would more effectively recover power costs.

Although we are not proposing any changes at this time, PSE anticipates the need to revisit the PCA Mechanism in a future general rate case to address the expiration of the $40 million cap at the end of the Fourth PCA Period on June 30, 2006.

2. Risk Management to Help Manage Power and Gas Costs

Q. Please describe PSE's approach to energy risk management.

A. As described above, PSE must balance numerous risk factors when obtaining energy resources to meet customer load. My staff and I work to identify these factors so 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) enhancing the value of PSE's energy resources to reduce power and gas costs. PSE utilizes risk management strategies to reduce volatility in power and gas costs, manage unused capacity, and increase the operational flexibility of assets. In addition to my testimony, below, additional details regarding PSE's risk management strategies are described in Exhibit No. ___(JMR-3).

Q. How does the Company try to reduce wholesale power price volatility on behalf of the power customers?

A. The Company uses a variety of hedging tools to reduce price volatility for power customers. The Company engages in forward market fixed-price purchases (both in physical gas and power purchase contracts and through financial market derivatives) to lock in gas prices, to purchase power as needed and to acquire

winter peaking capacity hedges. In addition, the Company utilizes flexibility in its resources to store hydro energy where possible, to dispatch and displace generation as market conditions provide economic signals, and to utilize transmission to move energy from resources to load.

Q. How does the Company try to reduce wholesale gas price volatility on behalf of the gas customers?

A. As with the power portfolio, PSE uses a number of tools to try to reduce price volatility for its gas customers. The Company engages in forward market fixed-price purchases (both in physical gas purchase contracts and through financial market derivatives) to lock in known prices for a portion of the gas supply. In addition, storage can be used for spot market volatility. For example, on a seasonal basis, the Company utilizes gas storage at Jackson Prairie and in Clay Basin to store generally lower-cost summer gas in order to help meet winter load requirements, when gas prices are generally higher. On a daily basis, we decide whether to pull supply from storage or inject into storage gas depending on spot market prices.

Q. How does PSE decide upon hedging strategies?

A. PSE assesses how a given hedging strategy will mitigate the risk exposure in the portfolio, then evaluates the costs to effectuate the hedge. There are many factors to consider and many uncertainties. Therefore, there is no single formula for weighing the cost/benefit analysis of a hedge strategy. There has to be a balance

between risk reduction, the opportunity costs associated with certain hedges, as well as outright costs with some hedges (such as options). We never know at the time decisions are made what the future will bring with respect to the volatility and risk factors described above.

Once a hedging strategy is determined to be appropriate, the Company determines how it may execute the strategy. This means evaluating the potential sellers of the hedge products and determining if PSE is in a contractual and credit position to execute those hedges.

Q. Are there constraints to putting on a hedge?

A. Yes. PSE's strategic options are constrained by several factors. Market liquidity is one constraint, for there may not be sellers of the hedge transactions sought by the Company. Market conditions may also make certain products very expensive. For example, an option contract such as a call, which is the right, but not the obligation, to purchase energy at a predetermined price, might be very attractive as a means to manage load variability risk, but in volatile markets, the cost of that option might be prohibitive. PSE's strategic options are also constrained by counterparty issues. The Company seeks to enter into transactions with a range of financially strong counterparties to reduce the risk of default by any one counterparty. Finally, as described below, PSE's own credit position can limit its ability to enter into hedging transactions.

Q. How far forward is the Company generally able to hedge in power and gas markets?

A. Power markets are short-term in nature, generally 6 to 18 months forward, and relatively illiquid. There is not much of a financial market, and most transactions result in physical delivery.

In natural gas, there are both physical and financial markets available to us for hedging fuel requirements for the gas fired power units. The physical fixed-price products are relatively liquid for up to 6 to 18 months forward, though there is more of a long-term gas market on account of the financial derivatives markets. Physical index contracts, where supply is purchased at a monthly index price, are available for up to 3-5 years in duration. In the financial markets, banks and large energy firms may be willing to sell fixed priced products for five years, and possibly 7-10 years for liquid market locations such as Henry Hub (onshore Louisiana) and AECO (Alberta, Canada).

However, as described below, the Company's current financial condition and credit or collateral requirements associated with these products limit the Company's ability to enter into longer term hedges.

Q. How could the Company hedge a larger portion of its portfolios?

A. With a better credit rating, we anticipate counterparties would be willing to sell more fixed-price supply or other hedge transactions to us, thereby expanding our hedging capability. While we would continue to develop strategy for hedging

linked to price signals, fundamental analysis and risk analysis, when prices were opportunistic, PSE believes it is important to have the capacity and flexibility to hedge more, and further forward in time.

Q. Looking forward, what will the hedging requirement be for the power portfolio?

A. As discussed in Mr. Eric Markell's testimony, Exhibit No. ___(EMM-1CT), the power portfolio will become increasingly short in the future. Until PSE can meet its growing needs by acquiring long-term resources, the Company will be dependent upon the power markets. This dependency increases the variability of power costs unless we can offset this market risk with more flexibility in our hedging capabilities. As the Company's short position grows, the need to purchase supply grows. In addition, if the Company acquires additional natural gas-fired generation, that could significantly increase the volumes of gas that PSE must consider hedging to reduce price volatility. Either scenario will further strain existing credit and contractual agreements.

Q. Looking forward, what will the hedging requirement be for the gas portfolio?

A. Per our 2003 gas Least Cost Plan, gas demand is expected to increase our gas purchase requirements and gas hedging needs if we were to maintain the same hedging profile mix in the future. In the period of 2005 to 2010, loads are expected to increase an average of 2.6% per year, and the incremental increase in

volume is estimated to be approximately 32,000 Dth/day. *See* Mr. Eric Markell's Exhibit No. ___(EMM-4).

3. New Short-term Market Developments

Q. Please describe recent developments in the regional power and gas markets.

A. Many large energy companies that participated actively in the regional power and gas markets just a few years ago do not do so today. Numerous trading and marketing companies have exited completely or reduced their activity in the region. Several utilities have closed their power market affiliates and operate only as utility buyers and sellers. The number of companies with which PSE engages in significant power transactions has dropped by approximately 48%. The number of companies with which PSE engages in significant gas transactions has dropped by approximately 46%. Exhibit No. ___(JMR-4C) shows the reduction of PSE's gas and power counterparties from 2001 to 2004 with which we do significant business.

Q. Are regulated entities having financial difficulty in current market conditions?

A. Yes. Most of PSE's traditional utility counterparties are, like PSE, load-serving entities ("LSEs"). These companies appear to be focused primarily on meeting their immediate and expected load obligations and are less active in forward market transactions. From what we see in trying to execute hedge strategies, most LSEs are transacting a maximum of three to six months out, and like PSE, most of

them are net buyers of natural gas and power. For these reasons, and due also to the reduced creditworthiness of many LSEs, it is difficult to obtain a longer-term product from these entities today. In fact, several of our transacting counterparties have filed for bankruptcy or are currently rated below investment grade. *See* Exhibit No. ___(JMR-5).

With respect to natural gas suppliers, prior to 2002 there were more gas marketers and aggregators providing marketing services to customers. Many of these entities no longer exist or do not have the corporate balance sheet necessary to attract gas producers to dedicate supply to them. Two new trends have emerged: (1) large-sized gas producers seek to market their production directly to gas users; and (2) there have been a few new entrants to the gas marketer and aggregator segment who have begun developing upstream marketing services to producers to fill the void. Additionally, some of the large gas producers (major oil companies) are beginning to aggregate volumes for smaller marketers and more actively market to downstream buyers such as utility companies. *See* Exhibit No. ___(JMR-4C) for a listing of counterparties with which the Company conducts significant business.

4. Credit Issues Are a Major Concern

Q. Why is credit an important factor in today's power markets?

A. A company's financial condition, and thus its creditworthiness, is the lens through which all prospective buyers and sellers in the markets--including PSE--look at

and evaluate potential counterparties. Many companies have incurred large losses during the last few years, with some even being forced into bankruptcy. Consequently, creditworthiness has become a very important factor in determining the companies with which PSE can transact.

Q. How does a counterparty's financial condition affect PSE's risk exposure?

A. If PSE agrees to purchase an energy product from a counterparty, but that counterparty fails to deliver the product when required, then PSE must go to the market to replace the product--perhaps at a much higher cost. PSE could, of course, bring a claim against the defaulting counterparty for the incremental costs required to cover PSE's position. But if the counterparty's financial condition is weak, then PSE may never recover those costs.

A similar analysis applies if PSE sells an energy product. If PSE delivers a product to a counterparty, but the counterparty fails to pay for the product, then PSE loses the entire value of the energy that has been delivered. In addition, PSE faces the exposure risk of having to resell the remaining amount of the contracted supply to someone else at a potentially lower price.

Counterparties to potential transactions with PSE face the same risks with respect to PSE's performance.

Q. Are debt ratings relevant to PSE's discussions with potential counterparties?

A. Yes. Typically a company will not transact with a potential counterparty until it evaluates the counterparty's debt rating and other financial indices and

determines--based on those factors--that the counterparty will likely have the financial capability to perform its contractual obligations.

PSE has the lowest "investment grade" debt rating, while most of our gas and power suppliers have stronger credit ratings. This puts us in a weaker negotiating position with those suppliers. PSE's credit rating and the credit ratings of PSE's currently approved counterparties are set forth in Exhibit No. ___(JMR-6C).

Since the Western energy crisis, and the financial decline of many merchant power plant operators, energy marketing companies, and western region investor-owned utilities, energy suppliers have become very conservative. When a company has a higher credit rating, counterparties are more comfortable increasing the level of business.

Q. How do counterparties address these credit risks?

A. Typically, counterparties extend a certain amount of "open credit" to each other. When a fixed-priced hedging transaction is entered into, it sets a price for the commodity comparable to market prices at that time. Then, depending upon the terms negotiated between the parties, PSE or the counterparty is required to provide collateral as the transaction's value begins to exceed the amount of open credit each has extended to the other, as measured on a mark-to-market basis. For large transactions or those that extend beyond shorter-term time horizons, companies increasingly look for some sort of collateral terms in the agreement. For example, if the Company locked-in 10,000 Dth/day of gas delivered over a

10-year period at $4.35/Dth and the market price moved $1.00 to $3.35/Dth, this would translate into over a $36 million net present value mark-to-market exposure. This would trigger a requirement to post collateral if the $36 million caused PSE to exceed the amount of open credit extended by that counterparty. If PSE had "used up" its open credit with a counterparty, it would be required to post collateral up front as a condition to entering into any more transactions with that counterparty.

Q. Does PSE have concerns about posting collateral?

A. Currently, it is PSE's general policy not to enter into transactions that would require the Company to post collateral for the reasons described in Mr. Don Gaines's testimony, Exhibit No. ___(DEG-1CT), and Mr. Bert Valdman's testimony, Exhibit No. ___(BAV-1T). The primary concern is to make sure the aggregate collateral requirements, in connection with other working capital needs, do not exceed what the Company could use under its bank credit lines.

The Company's reluctance is due, in part, to the fact that it is already subject to a number of agreements under which it can be required to post collateral. See, for example, Exhibit No. ___(JMR-7C). In addition, the Company is required to post collateral to a gas transportation company whose tariff has credit terms associated with debt ratings. The tariff for Gas Transmission Northwest (GTN) provides that "creditworthiness for firm service may be evidenced by an unenhanced rating for senior unsecured debt of at least BBB or Baa2 from Standard & Poor's or

Moody's, respectively, or an equivalent rating as determined by GTN." The Company is currently required to post a $474,000 letter of credit to GTN based on their credit standards.

Q. What indication does PSE have that a change in credit rating would impact the credit extended to PSE?

A. Exhibit No. ___(JMR-7C) lists PSE's current Financial Counterparties & Ratings Triggers. This exhibit shows agreements we currently have with financial counterparties and the impact a one- or two-notch decrease in our credit rating would have on our open credit. It also indicates how the open thresholds written in current agreements would change as a result of a drop in ratings. PSE has also conducted an informal survey of its major gas, power and financial counterparties to better understand how it is viewed at (i) its current corporate debt rating, (ii) one level lower, and (iii) one level higher. The surveyed counterparties were not able to indicate the exact amount of the increase or decrease to our open credit, as they would have to consider the factors causing the credit rating change. Nevertheless, the results of this survey show directionally that an improved credit rating can be expected to expand the Company's ability to enter into hedging transactions. Also of note is that a downgrade to the Company would result in the loss of a substantial amount of unsecured credit.

Additional credit that may be extended to PSE for financial transactions as a result of an increase in its credit rating of one level would be approximately 32%, or $23 million. For physical gas transactions, we estimate a 49% increase in

credit, or $74 million. For physical power transactions, we estimate a 67% increase in credit, or $99 million. We believe the impact of a two-level increase in ratings would be correspondingly higher.

It is important to note that the decrease associated with a downgrade is greater than the impact of an increase in credit rating. If PSE were downgraded according to this survey, PSE could potentially lose 44% of existing financial credit ($31 million), 67% of gas credit ($100 million), and 73% of power credit ($109 million). *See* Highly Confidential Exhibit No. ___(JMR-8HC).

Q. Can you provide some examples to help illustrate the impact of this potential increase in open credit?

A. Recall the mark-to-market example described above. PSE monitors its existing hedging agreements and exposure based on potential swings in market price. In considering whether it has sufficient credit to enter into new hedging transactions, PSE conservatively estimates the potential for a market move, in order to be assured that its exposure for the hedge would be covered by existing credit. Assuming a potential price move of $2.00/Dth, for every $60 million of credit extended to PSE, an approximation of gas volumes that PSE could potentially hedge without additional cost or exposure, include:

- 10,000 Dth/day of gas delivered over a 10-year period at a fixed price;
- 20,000 Dth/day of gas delivered or a 5 year period at a fixed price; and
- 90,000 Dth/day of gas delivered over a 1-year period at a fixed price.

To put this into perspective, in 2003 PSE delivered 815,696,000 therms of gas to sales customers, which averages to approximately 220,000 Dth per day. From the perspective of fuel consumption for the power portfolio, a 250 MW plant with a 7100 heat rate and an 85% dispatch rate would use an average of 36,000 Dth/day.

There is no hard and fast rule for calculating the amount of credit required for hedging, because of the subjective nature of estimating where market prices might go. Also, it is important to understand that these credit requirements are not fixed unless they are stated in the governing agreements. Therefore, a counterparty may change its credit assessment of PSE, as PSE may change its assessment of the counterparty, for various reasons including but not limited to: (i) market price volatility; (ii) industry events such as the Western energy crisis or the Enron bankruptcy; and (iii) changes in the financial strength of the Company.

Q. Would improvement of PSE's credit rating increase its access to hedging transactions?

A. Yes. If the Company had a higher credit rating, counterparties would extend more open credit to the Company, thereby enabling us to expand our hedging capacity for the power and gas portfolios without incurring costs to post collateral and without increasing debt. This benefits customers as the Company has an increased hedging capacity, without additional credit costs.

Q. Given its current credit situation, what is PSE currently doing to enhance its hedging capability?

A. PSE strives to make transactional decisions that use open credit effectively, leaving credit available to hedge positions. We have several approaches to help increase the credit available to us.

First, we enter into "netting" arrangements with counterparties. In these transactions, PSE works with a potential counterparty with the objective of "netting" the companies' respective payable and receivable positions associated with all outstanding transactions. This lowers exposure to payment risk between the parties and, in effect, opens more credit.

Second, PSE seeks to expand its current counterparty list, and is open to working with any new company for physical power and gas supplies if those companies meet our credit and contractual requirements.

Third, PSE dynamically monitors credit utilization and frequently updates counterparty filters on electronic exchanges and advises the voice brokers of the counterparties with whom it can transact. For each significant counterparty, PSE carefully monitors the amount of credit extended against the amount of transactions, to decide what product and delivery period it can further transact with each counterparty.

Fourth, PSE tries to understand which positions hold the greatest risk exposure and focuses hedging activities to those issues first.

Fifth, as discussed by Mr. Eric Markell, PSE is making acquisitions that will help PSE manage its short-term credit situation. The acquisition of an ownership interest in the Frederickson 1 facility is an example of such a transaction.

Q. What new trends are developing in gas transportation and electric transmission with respect to creditworthiness?

A. There are new developments with respect to creditworthiness that will put significant pressure on parties with low investment grade and below investment grade ratings. With respect to transmission, the California ISO has imposed restrictions based on credit ratings. At the present time, PSE would need to post collateral to transact in that market because PSE does not meet the short-term or long-term credit rating criteria.

Another indication of tightening credit policy in electric transmission can be found in the Stage 2 filing of RTO West to the FERC in March 2002. In this filing, the Regional Transmission Organization (RTO) considers establishing rigorous credit standards and recognizes that such standards could result in the disqualification of a number of parties. The filing also suggests collateral requirements when parties may not be able to meet these requirements. This is another example of how debt ratings influence the amount of open credit a counterparty is granted.

III. NORMALIZED POWER COSTS

Q. Please describe how PSE projected its normalized proforma net power costs in this filing.

A. Consistent with prior general rate cases, PSE made adjustments to the test year ended September 30, 2003 power cost data. The effect of these adjustments is to develop projected power costs for the rate year beginning March 1, 2005. As discussed by Mr. John Story in his testimony, Ex. No. ___(JHS-1T), the resulting projected power supply costs were then adjusted to test year levels by multiplying by an adjustment factor. This adjustment factor represents the ratio of weather normalized delivered energy loads for the test period to the rate year.

PSE uses an hourly dispatch model to project its normalized net power costs for the rate year. PSE used the AURORA model--a fundamentals-based hourly production cost model--to develop its model results. Exhibit No. ___(JMR-9) provides a summary of the AURORA model.

Consistent with the 2001 general rate case and PCORC filing, PSE adopted an average of the forward market prices for natural gas over a 10-business day period ending on January 8, 2004 to project natural gas prices for the rate year.

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

A. PSE is using the 60-year streamflow history in its normalized net power costs. PSE has also prepared projections of its power costs using a 40-year streamflow

history as the Commission required in the Company's 1992 general rate case. The 40-year information is provided in my workpapers.

Q. Why has PSE used the 60-year streamflow history rather than the 40-year streamflow history?

A. PSE engaged Dr. Jeffrey Dubin, Associate Professor of Economics at the California Institute of Technology (Caltech), to review the 60 years of available hydro data for PSE's Mid-Columbia and Westside projects for the period 1928-29 through 1987-88. Dr. Jeffrey Dubin has prefiled testimony in this proceeding, Exhibit No. ___(JAD-1T), concluding there is no statistical basis to exclude any of the available historical streamflow data and that the best data to use for a normalized forecast is the average of all available historical data, which at present is 60 years. An additional ten years of data is expected to be available during the summer of 2004. The Company proposes to supplement its filing with that additional data when it becomes available.

Q. Please quantify PSE's normalized net power cost projection.

A. Based upon 60 years of streamflow data, PSE's projected rate year net power costs, including production operations and maintenance ("O&M") expenses, are $782.6 million. *See* Exhibit No. ___(JMR-10). Mr. John Story adjusts this cost to a test period level per his Exhibit No. ___(JHS-E3, page 2.03).

Q. How has PSE developed its forecast of Production O&M costs in this filing?

A. In estimating its rate year power costs, PSE has made the following adjustments to its test year (October 2002 through September 2003) production O&M costs:

i) Restated the test year costs for Colstrip coal handling costs which have been reclassified to fuel costs to be in accordance with FERC accounting;

ii) Proformed the Colstrip O&M costs to preliminary rate year budget amounts;

iii) Removed the White River O&M costs to reflect retirement of the project for hydroelectric generation purposes;

iv) Proformed the O&M costs of the new Frederickson 1 resource based on forecasted operation and maintenance costs;

v) Restated the test year to normalize O&M for major maintenance for PSE's owned simple-cycle gas and oil-fired combustion turbines based on operating cost studies;

vi) Restated the test year to normalize O&M for major maintenance for PSE's owned Encogen plant based upon operating cost studies;

vii) Proformed the Whitehorn 2 & 3 lease costs to reflect the lower costs of the lease extension; and

viii) Proformed the Fredonia 3 & 4 lease costs to reflect the lower rate year lease costs.

Q. Please describe the principal differences between this forecast of normalized power costs and the forecast of normalized power costs that is included in the Company's PCORC filing.

A. Please refer to Exhibit No. ___(JMR-11)**,** which shows a comparison of the PCORC normalized power costs for the period April 2004 through March 2005 and the forecasted normalized power costs for the rate year.

In terms of supply / demand balance, the new forecast shows an increasing generation supply deficit due to load increases and continuing reduction in PSE's contract share with the Mid-Columbia operators.

This supply deficit is partially offset by increased generation from PSE's existing gas and oil-fired resources, including the Frederickson 1 plant. On average, the market heat rates are higher in the new forecast, causing this increased generation. Therefore, this forecast projects fewer market purchases to meet PSE's loads.

In terms of the impacts on power costs, higher natural gas prices are driving higher costs for generation from PSE's gas and oil-fired resources. In turn, these higher gas prices result in higher power market prices, which increase the cost of the net market purchases in the forecast. Other factors affecting power costs include changes in the planned maintenance for PSE's Westside hydro, Colstrip

and Sumas, as well as escalation in the costs of PSE's existing power purchase contracts.

Altogether, this forecast of power costs, including production O&M, is approximately $39.4 million higher than what is presently reflected in PSE's PCORC filing PCA Power Cost Baseline Rate.

Q. Does this conclude your testimony?

A. Yes, it does.

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