EXH. PKW-1CT
DOCKET UE-19____
PCA 17 COMPLIANCE FILING
WITNESS: PAUL K. WETHERBEE

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of the Petition of PUGET SOUND ENERGY For Approval of its April 2019 Power Cost Adjustment Mechanism Report	Docket UE-19____

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

**REDACTED
VERSION**

APRIL 30, 2019

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
PAUL K. WETHERBEE

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF PAUL K. WETHERBEE

I. INTRODUCTION

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

A. My name is Paul K. Wetherbee. My business address is 2380 116th Ave NE, Bellevue, Washington, 98004. I am the Director, Energy Supply Merchant for Puget Sound Energy ("PSE").

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

A. Yes, I have. It is Exh. PKW-2.

Q. What are your duties as Director, Energy Supply Merchant?

A. I am responsible for oversight of all Front Office activities including power and gas trading, the hedging program, and the dispatch of PSE's generating assets and related transmission.

Q. Please summarize the contents of your testimony.

A. First, I provide background information regarding the Power Cost Adjustment ("PCA") mechanism. I then describe PSE's management of power costs during the period that began on January 1, 2018 and ended on December 31, 2018 ("PCA Period 17"). Finally, I compare PSE's actual allowable power costs for PCA Period

17 to the baseline variable power costs included in rates during PCA Period 17. The baseline power cost rate approved in PSE's 2017 general rate case, Docket UE-170033 ("2017 GRC") went into effect December 19, 2017 and remained the effective rate for all of PCA Period 17. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, contains further information regarding the baseline rate for PCA Period 17.

II. BACKGROUND REGARDING THE PCA MECHANISM

Q. Why does PSE have a PCA mechanism?

A. Volatility in wholesale energy markets coupled with variations in power supply and load volumes can lead to significant differences between the actual cost of PSE's power supply portfolio and the costs currently included in customer rates. The PCA mechanism seeks to balance the risk of such power cost differences between customers and PSE by providing a method to share costs and benefits if power costs deviate significantly from those embedded in rates.

The PCA mechanism originally took effect on July 1, 2002 following a settlement agreement that originated in PSE's 2001 general rate case. As part of PSE's 2013 power cost only rate case, Docket UE-130617, PSE and parties to that proceeding initiated a collaborative process to address issues relevant to the PCA mechanism. That process resulted in a multiparty settlement that changed certain elements of the PCA.

The multiparty settlement was approved by the Commission and the changes became effective on January 1, 2017.

Q. How does the PCA mechanism work?

A. The PCA mechanism accounts for differences in PSE's actual power costs relative to the power cost baseline included in rates. The costs or benefits of such power cost variances are shared between PSE and customers according to three graduated levels of power cost variance or sharing bands. The dead band includes the first $17 million of power cost variance (positive or negative). Within the dead band, 100 percent of costs or benefits are retained by PSE. The first sharing band includes power cost variances between $17 and $40 million (positive or negative). Within this band, costs (under-recovered) are shared 50 percent to PSE and 50 percent to customers while benefits (over-recovered) are shared 35 percent to PSE and 65 percent to customers. The second sharing band includes power cost variances over $40 million (positive or negative). All variances in this band are shared 10 percent to PSE and 90 percent to customers, regardless of whether they are costs or benefits.

The customers' share of power cost variances is accounted for each year and deferred until the cumulative balance in the deferral account triggers a surcharge or refund. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T contains further information regarding the accounting for the cumulative balance.

III. PCA PERIOD 17 POWER COSTS

A. <u>PCA Period 17 Power Resources</u>

Q. Were there any changes to PSE's electric supply resources during PCA Period 17 relative to those included in the baseline rate?

A. Yes. As noted above, the baseline rate in effect during PCA Period 17 reflected the power portfolio from PSE's 2017 GRC. PSE's actual PCA Period 17 power supply portfolio included:

(1) Updates to power contracts and resources to reflect current operations, contract terms, and planned maintenance; and

(2) A new power purchase agreement with Douglas County Public Utility District ("PUD") for 5.5 percent of the output of the Wells Hydroelectric Project beginning September 1, 2018.

Q. What are the terms of PSE's new power purchase agreement with Douglas County PUD?

A. PSE's new power purchase agreement with Douglas County PUD provides for the purchase of 5.5 percent of the Wells Hydroelectric Project output for a term of 37 months beginning September 1, 2018. This 5.5 percent share includes approximately 42.5 megawatts ("MW") of capacity and 25.5 average MW of energy. PSE pays Douglas PUD a fixed price of [redacted] per month according to this agreement.

Q. Did PSE acquire any other new resources during PCA Period 17?

A. Yes. PSE acquired new resources in the form of off-system physical or financial purchases and sales of power and fuel to generate power. The majority of these transactions were short-term purchases of power and natural gas. Such transactions are made in response to changes in load or resource availability as well as changes in market heat rates, which guide PSE's decisions of whether to dispatch gas-fired generation or to buy power in the market. Such transactions were entered into pursuant to PSE's Supply Hedging and Optimization Procedures Manual ("Procedures Manual").

Q. What governance does PSE have over the various transactions described above?

A. PSE's Energy Supply Merchant ("ESM") department is composed of energy market analysts, energy traders, and other professionals. The ESM department develops and implements portfolio management strategies and transacts in the markets for power and gas. The ESM department was under my direction for all of PCA Period 17.

PSE's Energy Risk Control ("ERC") department is responsible for independently monitoring, measuring, quantifying and reporting official risk positions and performing credit analysis. The ERC department is led by the Corporate Treasurer.

PSE's Energy Management Committee ("EMC"), composed of five PSE officers, oversees the activities performed by both the ESM and ERC departments. 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. PSE's Procedures Manual and Energy Risk Policy lay out the policies that govern energy portfolio management activities and define roles and responsibilities of various departments. In addition, PSE's Board of Directors provides executive oversight of these areas through the Audit Committee.

B. <u>PSE's Management of its Power Portfolio and Related Fuel Supply for PCA Period 17</u>

Q. What actions does ESM take to manage its power costs within its governance structure?

A. PSE's ESM uses a combination of least cost dispatch, optimization, and portfolio hedging to manage power costs.

Q. Please explain least cost dispatch.

A. The ESM department plans for sufficient generation capacity to meet the forecasted day-ahead demand for electricity plus a reserve margin. PSE uses a least-cost dispatch approach for all resources, considering transmission and generation constraints. This strategy minimizes portfolio costs by seeking the most economic supply, whether generated or purchased in the wholesale market.

Q. Please explain optimization.

A. Given PSE's resource adequacy planning standard to meet peak hour loads, many days out of the year there is excess capacity. To optimize the portfolio, ESM staff maximizes asset value by selling excess transmission, generation, and natural gas pipeline capacity (not utilized for load) into the regional markets. Portfolio optimization activities align with PSE's Energy Risk Policy and Procedures Manual.

Q. What are the current hedging strategies approved by the EMC?

A. The purpose of hedging is to reduce the effects of price volatility on power costs. PSE's hedging program is managed in accordance with the EMC-approved Procedures Manual. The Procedures Manual provides guidance and risk management strategies for hedging exposure in two different time periods, the Programmatically Managed Hedge Period and the Actively Managed Hedge Period.

The Programmatically Managed Hedge period begins [redacted] in advance of delivery. The ESM department uses the Programmatically Managed Hedge program to systematically reduce PSE's net power portfolio exposure (including natural gas for power generation) so that as a month rolls into the Actively Managed Hedge period the exposure for that month will be within the monthly EMC-approved exposure limit.

The Actively Managed Hedge program begins [redacted] in advance of delivery. During this period ESM staff monitors positions on a daily basis and authorized traders execute transactions to manage exposure within monthly and [redacted] authority limits established by the EMC.

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

A. PSE's risk system employs 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 allows PSE to model scenarios with variable prices, hydro conditions, load projections, generation and contracted resources, and other inputs to estimate future portfolio needs. The risk system includes executed power and gas hedges in the portfolio.

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 efficiency, start-up costs, variable operating costs, minimum run times, and outages. The model 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 probabilistic position. The risk system incorporates the inter-relationship between gas and power prices in developing its probabilistic gas and power positions. PSE's gas or power requirements will change in different scenarios as plants become economic to dispatch depending on the price differential between power and gas. Output from the risk system is used to calculate PSE's net energy position and power portfolio exposure.

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

A. Once PSE's aggregated energy position and net exposure are defined for a particular period, the ESM department executes transactions for the purchase or sale of gas or power to stay within EMC-determined exposure limits. Execution entails entering into specific transactions with approved counterparties under approved master agreements subject to credit limits.

Q. Does the ESM department rely only on net exposure to implement the hedge programs?

A. No. Net exposure drives transactions only to the point of showing whether PSE's exposure is within the monthly parameters of the program. The ESM department then analyzes market prices and fundamentals that impact the wholesale electric and gas markets to decide on the specific volume to hedge. The ESM department also determines when and with whom to execute such transactions to manage net exposure.

Q. What information does the ESM department rely on to inform portfolio management decisions?

A. In addition to the output of the risk system, the ESM department utilizes a wide set of tools and sources of information to make informed decisions about dispatching plants, purchasing fuel, and executing hedges within EMC-approved limits. The ESM department collects and analyzes regional supply and demand data such as weather trends, gas storage inventories and hydro generation conditions. Additionally, the ESM department reviews forecasted wholesale market prices, industry publications, and real-time information from sources including Intercontinental Exchange ("ICE") Data and Analytics, live ICE price data, and brokers.

The ESM department holds regular meetings to review operational events, discuss market trends, and review supply and demand information. Within this context, the team works together to understand exposures in the portfolio and determine hedging priorities.

The ESM department may also use 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 current strategies.

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

A. Yes. The ERC department is responsible for establishing and monitoring counterparty credit limits in accordance with the EMC-approved Credit Risk Management Policy. Counterparty-specific exposure is calculated and monitored frequently, and ESM staff is permitted to transact only within established credit limits.

C. PSE's PCA Period 17 Actual Power Costs

Q. How did PSE's actual power costs for PCA Period 17 compare to power costs recovered through rates?

A. During PCA Period 17 PSE recovered $681.1 million of power costs through the variable baseline rate and incurred actual allowable power costs of $684.6 million. This $3.5 million under-recovery is within the $17 million dead band, so PSE will absorb the full amount and there will be no sharing of costs with customers.

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

A. The actual costs of power delivered to PSE's system always differ from those established in rates because actual power costs reflect the actual resources available to PSE and the realized outcome of multiple power cost variables. These variables include:

(i) Weather and power usage uncertainty affecting demand (load),

(ii) Streamflow variation affecting the supply of hydroelectric energy,

(iii) Unplanned generation outages,

(iv) Contract obligations,

(v) Output from variable energy resources,

(vi) Transmission and transportation constraints, and

(vii) Market volatility.

Further, while power costs included in rates are estimated "as closely as possible to costs that are reasonably expected to be actually incurred,"[1] estimates are limited by regulatory normalizing assumptions. Specifically, rates established in the 2017 GRC normalized power cost variables by utilizing:

(i) A weather normalized load forecast,

(ii) 80-years of streamflow data to determine hydro generation,

(iii) Forecasted average wind generation,

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

(iv) Gas price forecasts based on a three-month average of forward prices,

(v) Model-generated market power prices, and

(vi) Historical average forced outage rates.

Q. What were the primary causes of differences between PSE's actual power costs and power costs recovered in rates during PCA Period 17?

A. During PCA Period 17 PSE's total actual allowable power costs were $3.5 million higher than power costs recovered in rates. This under-recovery is the net result of lower revenue (due to lower delivered load) and lower actual costs. Actual delivered load for PCA Period 17 was 846,340 MWh less than the amount in rates, reducing revenue by $27.8 million at the baseline rate of $32.895 per MWh. This revenue decrease was largely offset by cost reductions from generating and purchasing less energy to serve the lower customer demand. Total power purchases and generation for PCA Period 17 were 1.1 million MWh lower than the amount in rates, reducing total power costs by $24.8 million. The net under-recovery associated with load changes relative to rates explains $3.0 million of PSE's total $3.5 million under-recovery. The remaining under-recovery resulted from differences in resource generation and costs. Table 1 below provides a comparison of the resources used to serve load relative to the resources included in rates.

Table 1: 2018 Generation and Load Relative to Rates		
	Change	Change
Generation higher / (lower) than rates:	aMW	%
Hydro	(9)	-1.8%
Colstrip	51	11.6%
Gas-fired	(228)	-32.4%
Wind	(9)	-3.9%
Contracts	(9)	-2.0%
Market purchases and sales	75	22.1%
Load (generated, purchased & interchanged)	(128)	-4.8%
Delivered load	(97)	-3.9%

Table 2 contains a summary of the items contributing to the total $3.5 million under-recovery and their estimated impacts for PCA Period 17, including load differences discussed above.

Table 2: Components of PCA Period 17 Under Recovery ($ in millions)	
Over / (under) recovery - actuals vs rates:	**PCA 17**
Revenues	
Delivered load lower by 846,340 MWh	($27.8)
Allowed costs	
Load (GPI) lower by 1,125,546 MWh	$24.8
Hydro generation	($9.6)
Wind generation	($4.3)
Gas-fired generation and fuel	$33.3
Colstrip	($12.0)
Long-term contracts	$4.4
Transmission/wheeling	($3.1)
PG&E exchange contract	($1.5)
Other (PCA adjustments)	($7.6)
Total allowed costs	$24.3
PCA Period 17 under recovery	**($3.5)**

Q. How did differences in hydro and wind generation affect power costs during PCA Period 17?

A. Actual generation from PSE's hydro and wind assets during PCA Period 17 was 158,784 MWh lower than the amount included in rates. Lower actual volumes were replaced with market purchases during the period. The cost of these additional market purchases increased actual power costs by $13.9 million.

Q. What was the impact of long-term contract purchases on power costs during PCA Period 17?

A. Total long-term contract purchase volumes were 76,879 MWh lower than volumes included in rates for PCA Period 17. This volume variance is attributable to lower receipts under PSE's Klondike III wind contract and, in aggregate, PSE's Schedule 91 tariff contracts. Prices for these contracts are higher than actual market prices during PCA Period 17, so the reduced volumes were replaced with lower priced market purchases. The net impact of replacing these long-term contract volumes with market purchases was a $4.4 million decrease to power costs relative to the amount included in rates.

Q. Why were actual transmission costs higher than those included in rates?

A. The actual net cost of third party transmission during PCA Period 17 was $3.1 million higher than the transmission costs included in rates. This difference is primarily the result of lower offsetting revenue from short-term re-sales of BPA transmission, or transmission re-assignment revenue. Rates set in PSE's 2017 GRC included $6.4 million of transmission re-assignment revenue. Actual transmission re-assignment revenue during the period was $3.7 million.

Q. Please explain the power cost variance associated with Colstrip.

A. Total Colstrip generation for the year was higher than generation included in rates, but the plant experienced lower output during July and August. Lower generation during these months coincided with particularly high market energy prices, contributing to the estimated $12 million power cost increase attributed to Colstrip during PCA Period 17. See Exh. PKW-3 for daily settlement market power and gas prices for July and August.

Q. Why was Colstrip generation lower than amounts included in rates during July and August of PCA period 17?

A. Near the end of June 2018 Colstrip Units 3 & 4 were removed from service after test results indicated that particulate matter emissions from the units exceeded levels needed to comply with the national Mercury Air Toxics Standard. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1T, for a complete timeline and description of the standard and compliance testing at Colstrip. Between the end of June and early September, Units 3 & 4 were not available for normal operation and only ran in order to conduct additional testing, gather information, and evaluate attempted corrective actions. As a result of these limited operations, Colstrip Units 3 & 4 generated only 118 average MW during July and August compared to 297 average MW included in rates for these two months.

Q. How did PSE's ESM department manage power costs given the reduction to Colstrip 3 & 4 generation?

A. ESM staff received notice in late June 2018 that Colstrip Units 3 & 4 would be taken out of service with an initial expected return date of July 6 or 7. As a result of this information, PSE hedged a portion of the expected lost generation with weekly market power purchases totaling 100 MW on-peak at an average price of $24.25 per MWh. In addition, PSE had surplus gas-fired generation that was economical and expected to run during July, but had not been sold, resulting in net exposure of $[redacted] for the month of July. This [redacted] position effectively provided an option to manage fixed price exposure using PSE's gas-fired resources if the Colstrip outage was extended. See Exh. PKW-4C for PSE's portfolio exposure for July. Throughout July, high temperatures and natural gas issues in California contributed to increased power prices while limitations on Colstrip Units 3 & 4 continued.

Higher power prices extended into the forward month of August and the timing of a return to normal operations at Colstrip Units 3 & 4 remained uncertain. PSE hedged August on-peak fixed price risk with [redacted] fixed price contract purchases. At the end of July PSE's electric portfolio risk model indicated net [redacted] exposure of $[redacted] for August, which was driven by a [redacted] ne[redacted] power position from un-sold gas-fired generation. See Exh. PKW-5C for PSE's portfolio exposure for August. This model output, however, assumed that Colstrip Units 3 & 4 would be fully operational in August. Removing Colstrip Units 3 & 4 generation from the model would reduce total net exposure by $[redacted]

To manage August on-peak physical supply risk, ESM maintained [redacted] MW of surplus Mid C daily index [redacted] to offset continued lost supply from Colstrip Units 3 & 4 or any other unplanned events.

Even though the Colstrip outage resulted in higher power costs in July and August than were established in rates, actions taken by PSE to manage the portfolio in light of the outage prevented even higher power costs.

Q. How did changes to gas-fired generation and fuel costs affect power costs during PCA Period 17?

A. Total gas-fired generation during PCA Period 17 was nearly two million MWh lower than the amount included in rates. This generation difference is due primarily to lower actual market heat rates. The market heat rate is a measure of the cost of natural gas relative to the cost of market power – lower market heat rates indicate that it is more economical to buy power from the market than to burn natural gas for power generation. During PCA Period 17 the actual total cost of natural gas fuel and fuel transportation was $104.7 million lower than the amount included in rates. After accounting for the cost of market purchases used to offset generation, gas-fired generation and natural gas fuel contributed an overall net decrease of $33.3 million to PCA Period 17 power costs relative to amounts included in rates. A large part of this net power cost reduction, $24.5 million, occurred during the last two months of 2018 due to benefits from sales of natural gas fuel. These sales and resulting power cost benefits were the result of extraordinary market conditions caused by a disruption to the regional supply of natural gas.

Q. What caused the regional fuel supply disruption?

A. On October 9, 2018 a key pipeline bringing gas from British Columbia south to the US border at Sumas ruptured. Capacity to supply gas at Sumas has been and continues to be limited following the incident. This limited supply led to higher Sumas gas prices for the remainder of PCA Period 17.

Q. How did higher Sumas gas prices impact PSE's power portfolio?

A. At the time of the supply disruption PSE had already purchased natural gas hedges for November and December to supply PSE's gas-fired generators. As market natural gas prices increased, market heat rates decreased (gas prices increased relatively more than power prices) and PSE was able to sell hedged gas supply and purchase equivalent power for net gains. In addition, PSE was able to purchase gas at Stanfield, a location that was not directly impacted by the supply disruption, and utilize long-term firm pipeline capacity to move gas to Sumas and sell it at the higher prices. Though using this pipeline capacity to move gas from Stanfield to Sumas meant that it could not be used to supply PSE's gas-fired generators, the net gains from gas sales more than offset the cost of purchasing additional power.

IV. CONCLUSION

Q. Has PSE met the Commission's standard with respect to its power costs during PCA Period 17?

A. Yes, PSE met the Commission's standard for the PCA Period 17 power costs. PSE's management of its power costs during PCA Period 17 was reasonable. PSE has structures and processes in place to formulate strategies for managing power costs and executed those strategies, taking into account information and variables associated with managing a complex resource portfolio within a dynamic market environment. The deferral balance set forth in PSE's PCA Period 17 report is reasonable and in accordance with the amended PCA settlement and the Commission's orders in Docket UE-011570.

Q. Does that conclude your testimony?

A. Yes, it does.