BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.,

Respondent.

DOCKET NOS. UE-090704 and UG-090705 *(consolidated)*

DIRECT TESTIMONY OF SCOTT NORWOOD (SN-1T)

ON BEHALF OF

PUBLIC COUNSEL

REDACTED

NOVEMBER 17, 2009

DIRECT TESTIMONY OF SCOTT NORWOOD (SN-1T)
DOCKET NO. UE-090704 AND UG-090705

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I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Scott Norwood. I am President of Norwood Energy Consulting, L.L.C. My business address is P.O. Box 30197, Austin, Texas 78755-3197.

Q: By whom are you employed and in what capacity?

A: I am a self-employed energy consultant specializing in the areas of electric utility regulation, resource planning and energy procurement.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Public Counsel Section of the Washington Attorney General's Office (Public Counsel).

Q: Please describe your professional qualifications.

A: I have over 28 years of experience in the electric utility industry. After graduating from the University of Texas in 1980 with a Bachelor of Science degree in electrical engineering, I began my career as a power plant engineer for the City of Austin's Electric Utility Department where I was responsible for electrical maintenance and design projects for the City's three gas-fired power plants. In January 1984, I joined the staff of the Public Utility Commission of Texas as Manager of Power Plant Engineering. In that capacity I was responsible for addressing resource planning, fuel and purchased power cost issues presented in regulatory filings before the Texas Commission. In 1986, I joined GDS Associates, Inc., a Marietta, Georgia-based consulting firm that specializes in electric utility regulatory consulting and resource planning. I was elected a Principal of GDS in 1990 and directed the firm's Deregulation Services

Department until January 2004, when I left GDS to form Norwood Energy Consulting, LLC. The focus of my current consulting practice is energy planning, procurement and regulation. Exhibit No. SN-2 provides a more detailed summary of my background and experience.

Q: Have you previously testified before the Washington Utilities and Transportation Commission?

A: No. However, I have testified on behalf of consumers, government agencies, and consumer-owned utilities in numerous past regulatory proceedings before state regulatory commissions in Arkansas, Georgia, Illinois, Iowa, Louisiana, Michigan, Missouri, New Jersey, Oklahoma, Texas, Virginia and Wisconsin.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to present my analysis and recommendations regarding: 1) the prudence of PSE's acquisition of the Mint Farm generating facility, 2) PSE proposal to defer and recover fixed and variable costs of its Mint Farm facility from the acquisition through the effective date of new rates in this case; 3) PSE's updated rate year baseline power cost forecast; 4) the appropriate ratemaking treatment of revenues from PSE's sale of Renewable Energy Credits during the rate year period; and 5) PSE's announced development strategy for wind generation.

Q: What exhibits are you sponsoring in this proceeding?

A: I am sponsoring 11 exhibits, including my testimony.

II. SUMMARY OF TESTIMONY

Q: Please summarize your testimony and recommendations.

A: My testimony addresses a number of power supply related matters which impact PSE's requested $153.6 million base rate increase in this case. My primary findings and recommendations are as follows:

Mint Farm Prudence - Based on my review of evidence presented by PSE, and when evaluated based on the Commission's prudence standards, I have concluded that PSE's decision in August 2008 to acquire the Mint Farm facility was imprudent. I recommend that PSE's requested return on equity for the Mint Farm facility be disallowed in this case, but that the Company be allowed to recover other reasonable rate year costs of the facility. This recommendation, which reduces PSE's proposed revenue requirement by $19.475 million, should provide PSE with adequate revenues to fund the operations and maintenance of the Mint Farm plant, without rewarding PSE's shareholders for an investment that was not needed or appropriate in light of more beneficial available alternatives.

Mint Farm Deferral - I have concluded that PSE's proposal to defer and recover Mint Farm fixed and variable costs is unreasonable and inconsistent with the Company's obligations under the terms and conditions of its PCA mechanism, which provides two separate methods for recovering costs of new resources such as Mint Farm. Moreover, Mint Farm does not appear to meet the requirements to qualify for deferred accounting under RCW 80.80.60(6) and has not reduced energy costs on PSE's system during the proposed deferral period. For these reasons, I recommend that PSE's request to defer and recover Mint Farm costs be disallowed and that the Company's recovery of variable costs of Mint Farm should be made pursuant to the new resource recovery provisions as specified in Exhibit G of the PCA mechanism.

Baseline Power Cost Forecast - I am recommending several adjustments to correct problems with PSE's baseline power cost forecast which could otherwise serve to overstate costs during the rate year period. First, I recommend that PSE's rate year hydro generation forecast be revised to reflect the average hydro generation levels over the most recent 50-year period 1949-1998. This recommendation will serve to increase PSE's rate year hydro generation forecast by **[Begin Confidential]** XXXXXXX **[End Confidential]** for PSE's Mid-C hydro contract purchases and reduces PSE's rate year power costs by $5,569,835. Second, I recommend that a credit of $0.00201 per kWh be applied effective April 1, 2011, to offset the collection of gas Mark-to-Market costs embedded in PSE's proposed baseline power cost rate unless PSE changes its baseline power cost rate before that date. Third, I recommend that PSE's baseline power cost forecast be adjusted to reflect the average annual volume of off system sales made by PSE over the last 5 calendar years **[Begin Confidential]** XXXXXXXXX. **[End Confidential]** This recommendation reduces PSE's rate year power cost forecast by $5,141,295. Finally, I recommend that the Commission consider implementing a trigger mechanism to require PSE to file for a reduction in its baseline power rate at any time that natural gas prices are 15% or more lower than the level used in setting the Company's approved baseline rate.

Renewable Energy Credit Sales Revenues - I recommend that $51,057,512 of the estimated REC sales revenues during the rate year be applied as credits to reduce PSE's approved baseline power cost rate and to help mitigate the $153.6 million base rate increase requested by PSE in this case. I further recommend that the Commission adopt reporting and monitoring requirements for PSE REC sales to help ensure that customer benefits from such sales are being maximized.

The basis for my above recommendations are explained in the remaining sections of my testimony.

III. PRUDENCE OF MINT FARM ACQUISITION

Q: Please describe the Mint Farm facility.

A: The Mint Farm generating station is a natural gas-fired combined cycle combustion turbine plant located within the Mint Farm Industrial Park in Longview, Washington.[1] The primary equipment at the Mint Farm plant includes a General Electric Frame 7FA combustion turbine and generator, a Foster-Wheeler Heat Recovery Steam Generator and a Siemens-Fuji KN steam turbine and generator.[2] The Mint Farm project originally was developed by Avista Power in partnership with Steag AG, a large German power producer. Avista sold the development rights to the Mint Farm facility to Mirant Corporation in 2001. In August 2002, construction on the Mint Farm project was suspended with the

[1] Exhibit No. RG-1HCT, p. 28.
[2] Exhibit No. RG-1HCT, p. 28.

project 34% completed as a result of Mirant's financial distress and bankruptcy. Wayzata Investment Partners, LLC, (Wayzata) acquired the project from Mirant in December 2005 through a bankruptcy process and ultimately completed the project in 2007. The Mint Farm facility commenced commercial operations in January 2008.[3]

Q. What is the rated generating capacity of the Mint Farm facility?

A: The Mint Farm facility has a 260 MW nominal rating, plus 37 MW of duct firing capability and an additional 14 MW through steam augmentation under emergency conditions for short periods.[4]

Q: What events led to PSE's acquisition of the Mint Farm facility?

A: Through its 2007 IRP analysis, PSE identified a need for new capacity on its system, and therefore issued a request for proposals (RFP) for new generating capacity in January 2008. In late-February 2008, PSE received 31 proposals in response to its RFP.[5] After economic and qualitative evaluations of the proposals, the Company selected a shortlist of 13 bids, including a bid providing for PSE's ownership of the Mint Farm facility, for further evaluation.[6] After conducting due diligence, further economic analysis, and negotiations with the shortlisted bidders, PSE management selected the Mint Farm project along with three other bids as the winning proposals for potential acquisition.[7] PSE subsequently sought and obtained Board approval to proceed with acquisition of

[3] Exhibit No. RG-1HCT, p. 28.
[4] Exhibit No. RG-1HCT, pp. 28-29.
[5] Exhibit No. RG-1HCT, p. 5.
[6] Exhibit No. RG-1HCT, p. 13.
[7] Exhibit No. RG-1HCT, p. 24.

the facility on August 4, 2008. Definitive agreements for the Mint Farm transaction were executed on September 24, 2008 and closing occurred on December 5, 2008.

Q: What was the total acquisition price for the Mint Farm facility which PSE is seeking to recover in this case?

A: The total acquisition price of the Mint Farm facility was **[Begin Confidential]** XXXXXXXXXXX. **[End Confidential]** [8]

Q: What issues are raised by PSE's acquisition of the Mint Farm facility?

A: PSE is seeking a number of ratemaking determinations regarding its investment in the Mint Farm facility. First, the Company is seeking a determination that its acquisition of the Mint Farm facility was prudent.[9] Second, PSE is requesting that it be allowed to defer fixed and variable costs of the Mint Farm facility which it has incurred (and forecasts to incur) from the date of acquisition of the plant through the effective date of rates in this case.[10] The Company is also proposing a number of proforma adjustments to reflect the fixed and variable rate year costs of the Mint Farm facility in its new base rates.[11] In this section of my testimony I address the prudence of PSE's decision to acquire the Mint Farm facility and PSE's proposed adjustments to reflect Mint Farm costs in its new base rates. In the next section of my testimony I address the Company's request for deferral and

[8] Exhibit No. RG-1HCT, p. 44.
[9] Exhibit No. KJH-1CT, pp. 26-27.
[10] Exhibit No. JHS-1T, p. 66.
[11] Exhibit No. JHS-1T, pp. 22-25.

recovery of Mint Farm costs which have been incurred since the plant was acquired in December of 2008.

Q: What evidence has PSE presented to support the prudence of its Mint Farm acquisition?

A: PSE witnesses Harris, Garratt and Elsea are the primary witnesses that address the prudence of the Company's acquisition of the Mint Farm facility. Generally, the direct testimonies of these witnesses describe the resource planning, competitive procurement and management decision-making processes which culminated in PSE's decision in August of 2008 to acquire the Mint Farm facility.

Q: What standards have you applied in evaluating the prudence of PSE's decision to acquire the Mint Farm facility?

A: I have applied the same basic Commission-approved prudence standards as described on page 27 of Ms. Harris' direct testimony in evaluating the prudence of PSE's Mint Farm acquisition. The primary prudence standard I have applied is derived from the Commission's Order No. 12 in Docket No. UE-031725, PSE's 2003 Power Cost Only Rate Case (PCORC):

> The test the Commission applies to measure prudence is what a reasonable board of directors and company management would have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.

As explained further on page 28 of Ms. Harris' testimony, in its Nineteenth Supplemental Order in Docket No. UE-921262, WUTC v. Puget Sound Power &

Light Co., the Commission identified the following specific factors that should be considered in evaluating whether a utility meets the above prudence standard:

- First, the utility must determine whether new resources are necessary.

- Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself. The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, impact on the utility's credit quality, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision.

- The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.

- The utility must keep adequate contemporaneous records that will allow the Commission to evaluate its actions with respect to the decision process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.

Q: Did PSE maintain contemporaneous documentation to support its decision to select the Mint Farm acquisition proposal?

A: Yes. PSE maintained documentation summarizing its analysis of the Mint Farm facility and other generation bids received in response to its 2008 RFP. The Company also maintained documentation of due diligence analyses of the Mint Farm facility which were conducted during June and July of 2008 to further assess the design and operating condition of the plant.

Q: With regard to the first prudence standard, does the evidence presented by PSE demonstrate that it was necessary to acquire the Mint Farm facility in

December 2008 in order to meet PSE's native system capacity and energy requirements?

A: No. In fact, PSE's August 4, 2008, management presentation to the Company's board of directors in support of the Mint Farm acquisition indicated that the plant would **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXX XXXXXXX. **[End Highly Confidential]**[12]

Q: What alternatives did PSE consider before deciding to acquire the Mint Farm plant?

A: As noted above, PSE issued a request for proposals (RFP) for new generating capacity in January 2008 and received 31 proposals in late February in response to the RFP. [13]

Q: How did PSE evaluate bids it received in response to its 2008 RFP?

A: PSE evaluated the bids from its 2008 RFP in two phases. In the Phase I analysis, the Company identified the best options by conducting economic screening and qualitative analyses.[14] For the Phase I quantitative analysis, PSE ranked bids based on their portfolio benefits, the portfolio "benefit ratio" and the levelized cost of each proposal.[15] The portfolio benefits were measured by calculating the difference between the present value of system production costs as reflected in the Company's 2007 IRP and the present value of system production costs with the proposed resource included. The portfolio benefit ratio represents the system

[12] Exhibit No. RG-1HCT, p. 9 and p.19; PSE's Response to Public Counsel Data Request No. 209.
[13] Exhibit No. WJE-1HCT, p. 5.
[14] Exhibit No. RG-1HCT, p. 3
[15] Exhibit No. RG-3HC, p. 15.

benefit produced by a proposed resource divided by the present value of revenue requirements of that resource. Proposals with higher system benefits and higher portfolio benefit ratios provide greater benefits to customers and were ranked higher in PSE's quantitative analysis of proposals. Based on this economic screening and its qualitative evaluations of the proposals, in late April of 2008 PSE selected thirteen proposals for its Phase I "Candidate Short List" including five natural gas-fired projects, four wind projects, and four market power purchase agreements (PPAs).[16]

Q: Was Mint Farm the highest ranked proposal based upon PSE's Phase I quantitative analysis of bids received in response to the 2008 RFP?

A: **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXX.[17] XXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXX. **[End Highly Confidential]**[18]

[16] Exhibit No. RG-3HC, pp. 13-14.
[17] Exhibit No. SN-3HC.
[18] Exhibit No. RG-3HC, p. 33.

Q: What additional analysis did PSE conduct in its Phase II evaluation of the shortlisted bids before reaching its decision to acquire the Mint Farm facility?

A: In its Phase II evaluation, PSE conducted a more in-depth analysis of the costs and benefits of the Candidate Short List bids, along with an expanded qualitative analysis and technical due diligence analyses of leading bids to examine the design, physical condition and operating history of proposed projects.[19] The Phase II economic analysis evaluated the shortlisted bids both on a stand-alone basis and through portfolios of resources under a range of future gas price and load growth scenarios.[20] This Phase II evaluation of bids was concluded in late July of 2008 and formed the basis of PSE's final decision in August of 2008 to acquire the Mint Farm plant.

Q: Was Mint Farm the highest ranked proposal based on PSE's Phase II quantitative evaluation of the shortlisted bids?

A: **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX

[19] Exhibit No. RG-1HCT, pp.16-17.

XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXX. **[End Highly Confidential]** [21]

Q: Did PSE's economic analyses of the [Begin Highly Confidential] XXXXXX XXXXXX [End Highly Confidential]bid include an adjustment for the imputed debt cost associated with long-term purchased power agreements?

A: Yes. PSE's analysis of the **[Begin Highly Confidential]** XXXXXXXXXXXXX XXX**[End Highly Confidential]** bid included an imputed debt cost adjustment in the amount of**[Begin Highly Confidential]** XXXXX. **[End Highly Confidential]**[22] Without this adjustment, the benefits of this PPA bid would have been nearly three times PSE's estimated benefit for Mint Farm.

Q: Did PSE also conduct Phase II portfolio analyses to evaluate the economic benefits of the Short Listed bids when grouped with other new resources?

A: Yes. These analyses indicated that**[Begin Highly Confidential]** XXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX X. **[End Highly Confidential]**[23]

Q: Did PSE management keep its board of directors informed of the results of its analyses of Mint Farm and other shortlisted bids?

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[20] Exhibit No. WJE-1HCT, p. 16. Exhibit No. RG-3HC, pp. 22-25.
[21] Exhibit No. SN-4HC. Exhibit No. WJE-1HCT, pp. 15-18.
[22] PSE's Response to Public Counsel Data Request No. 514.
[23] Exhibit No. SN-5HC.

A: Yes. PSE's management provided a series of summary presentations and other information to its board of directors to explain the competitive procurement and bid evaluation process and results which ultimately led to its selection of the Mint Farm acquisition over other proposals. However, these board presentations did not fully explain why PSE management recommended that the board select the Mint Farm facility over a long-term PPA bid which was forecasted to provide more than double the system economic benefits attributed to the Mint Farm project. Moreover, PSE's board presentations appear to present an unduly favorable assessment of the Mint Farm facility which deemphasizes concerns identified by the Mint Farm due diligence analyses.

Q: Can you provide examples in which the Mint Farm due diligence analysis findings appear to be inconsistent with information provided by PSE to its board of directors?

A: Yes. For example, in memorandum included in PSE's August 4, 2008, board presentation, which recommended acquisition of the Mint Farm facility, the Company summarized the results of its due diligence analysis as follows:

> **[Begin Highly Confidential]**
>
> XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXX.[24]
>
> XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX.
> **[End Highly Confidential]** [25]

[24] Exhibit No. RG-7HC, p. 23.
[25] Exhibit No. RG-7HC, p. 168.

However, the Mint Farm Energy Center Due Diligence Report dated July 11, 2008, which was prepared by North American Energy Services Company (NAES) to support PSE's decision regarding Mint Farm, provides a much more qualified assessment of the design and condition of the facility.[26] Although the NAES Report concludes**[Begin Confidential]** XXXXXXXXXXXXXXXXXXXX, XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXX **[End Confidential]** the report also identifies a number of potential concerns and areas of uncertainty regarding the design and operations of Mint Farm. For example, NAES' due diligence report expressed the following specific concerns:

[Begin Confidential]

- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXX.

- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX.

- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXX.

- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXX.

[26] *See*, PSE's Confidential Response to WUTC Staff Data Request No. 23, PC-005.

- XXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXX.[27] **[End Confidential]**

Moreover, while PSE told its board that Mint Farm **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXX, **[End Highly Confidential]** NAES' due diligence report noted that **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX:

- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXX.[28]

- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXX [29]

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- XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXX. [31]**[End Confidential]**

[27] NAES Report, pp. 1-2.
[28] NAES Report, p. 2.
[29] NAES Report, p. 2.
[30] NAES Report, p. 2.
[31] NAES Report, p. 20.

Q: Did PSE identify other potential risks associated with ownership of the Mint Farm facility?

A: Yes. At the time it decided to acquire Mint Farm, PSE was aware that it did not have adequate firm gas transportation capacity to supply the full requirements of the Mint Farm facility, and the Company knew that it did not have sufficient firm transmission rights to deliver the full output of the Mint Farm facility to its system.[32] In addition, PSE was aware that Mint Farm had no backup fuel capability and therefore the output of the plant could be restricted if the natural gas supply to the plant is ever curtailed for any reason.[33]

Q: What was PSE's qualitative assessment of the [Begin Highly Confidential] XXXXXXXXXXXX [End Highly Confidential] bid?

A: PSE's Phase II. qualitative assessment of the **[Begin Highly Confidential]** XXXXXXXXXXXX **[End Highly Confidential]**described the project as follows:

[Begin Highly Confidential]

> XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
> XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
> XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
> XXXXXXXXXXXXXX.[34] **[End Highly Confidential]**

Q: In light of the fact that the [Begin Highly Confidential] XXXXXXXXXXX XX [End Highly Confidential] bid was estimated by PSE to provide more than double the economic benefits of the Mint Farm Facility and was

[32] Exhibit No. RG-1HCT, pp. 30-31.
[33] Exhibit No. RG-1HCT, p. 31.
[34] Exhibit No. RG-3HC, pp. 26-27.

generally viewed to have a solid operating history, why did PSE select Mint Farm over the [Begin Highly Confidential] XXXXXXXXXXXXX [End Highly Confidential] bid?

A: PSE has cited several reasons why it selected Mint Farm over the **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXX**[End Highly Confidential]**[35]

Q: Do the factors cited by PSE justify its selection of Mint Farm over the [Begin Highly Confidential] XXXXXXXXXXXXXX [End Highly Confidential]?

A: No. The fact that PSE's analyses indicate that the **[Begin Highly Confidential]** XXXXXXXXXXXX **[End Highly Confidential]** would be infrequently dispatched is not an issue for concern; it simply reflects the fact that PSE is expected to have access to other lower cost sources of energy on its system. The low dispatch level of **[Begin Highly Confidential]** XXXXXXXXXX **[End Highly Confidential]** does not alter the fact that PSE's studies indicated that this PPA was expected to provided much higher system production cost benefits than the Mint Farm facility. These results (i.e., higher benefits with relatively low dispatch) suggest that the benefits of the **[Begin Highly Confidential]** XXXXX XXXXXX **[End Highly Confidential]** are due to the lower fixed costs of the

[35] Exhibit No. RG-3HC, p. 27.

transaction rather than due to energy cost savings. This also suggests that the **[Begin Highly Confidential]** XXXXXXXXX **[End Highly Confidential]** benefits would also have been more certain since they were less dependent on the level of future natural gas and market energy prices, which are difficult to predict. In fact, under a number of scenarios which considered a wide range of fuel costs and load growth, PSE's analysis indicated that the **[Begin Highly Confidential]** XXXXXXXX **[End Highly Confidential]** provided much higher system production cost benefits than the Mint Farm facility.[36]

Q: What factors could have motivated PSE to acquire the Mint Farm facility when its own studies consistently showed that the [Begin Highly Confidential] XXXXXXXXXXXXXX **[End Highly Confidential] would provide much higher system production cost benefits than Mint Farm?**

A: The acquisition of Mint Farm potentially benefits PSE's shareholders by increasing the Company's rate base by approximately $230 million, and thereby providing an opportunity for additional shareholder return in the range of $25 million per year. In contrast the **[Begin Highly Confidential]**XXXXXXXXX XXX **[End Highly Confidential]**bid would have produced no significant shareholder benefit for PSE since there is no return component on purchased power costs. Other than this difference, I see no reason why PSE would have been motivated to select the Mint Farm acquisition over an option

[36] Exhibit No. SN-4HC.

such as the **[Begin Highly Confidential]** XXXXXXXX **[End Highly Confidential]** that was evaluated by PSE to provide superior economic benefits to PSE's customers while representing a less risky option than Mint Farm from the standpoints of timing of initial deliveries, operational performance, and power deliverability.

Q: Could PSE's decision to acquire the Mint Farm facility before it was needed to meet system capacity requirements have been motivated by the Company's expectation that the plant would produce sufficient energy savings to justify the Mint Farm investment and operating costs?

A: No. PSE estimated that the fixed costs of ownership of Mint Farm would be approximately $42 million per year.[37] This estimate of the fixed cost of owning Mint Farm was far higher than PSE's estimates of the variable production cost savings from Mint Farm which were forecasted to range from $1.2 million to $2.9 million per year.[38] In fact, as explained later in my testimony, when fixed gas transportation and wheeling charges are considered there are no expected production cost savings from the Mint Farm facility since the cost of energy supplied from the plant is approximately **[Begin Confidential]** XXXXXXX **[End Confidential]** than PSE's forecasted price of on-peak market energy purchases, which Mint Farm is expected to displace.

Q: Please summarize your findings and conclusions regarding the prudence of PSE's decision to acquire the Mint Farm facility.

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[37] Exhibit No. WJE-18.
[38] PSE's Response to Public Counsel Data Request No. 222.

A: When PSE's management and board of directors decided in August of 2008 to acquire the Mint Farm facility, **[Begin Highly Confidential]** XXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. **[End Highly Confidential]** PSE's economic analysis of the Mint Farm acquisition proposal and other resource bids that were received in response to the Company's 2008 RFP indicated that at all phases of the analysis and under a wide range of future scenarios, the estimated system production cost benefits provided by **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX**[End Highly Confidential]** bid were more than double the level of estimated benefits for the Mint Farm acquisition. PSE's due diligence analyses identified a number of potential risks and uncertainties regarding the condition and operations of Mint Farm which are related **[Begin Confidential]** XXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. **[End Confidential]** There also is risk of potential curtailment of Mint Farm energy deliveries as a result of inadequate firm transmission capacity, inadequate gas transportation capacity, and no backup fuel capability at the plant. In light of these facts, and when evaluated based on the Commission's prudence standards, I have concluded that PSE's decision in August 2008 to acquire the Mint Farm facility was imprudent.

Q: What is your recommendation regarding the Mint Farm costs which PSE is seeking to recover in this case?

A: Although PSE forecasted that Mint Farm would provide significantly lower system production cost benefits than the **[Begin Highly Confidential]** XXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXX **[End Highly Confidential]** the plant may ultimately benefit PSE's customers in the long run. Therefore, I recommend that PSE's requested return on equity for the Mint Farm facility be disallowed in this case, but that the Company be allowed to recover other reasonable rate year costs of the facility. My recommendation reduces PSE's proposed revenue requirement by $19.475 million, excluding the associated production factor adjustment, as developed by Public Counsel witness James Dittmer. Under my recommendation, PSE would collect sufficient revenues to reasonably fund the operations and maintenance, taxes, debt costs and other fixed costs of ownership of the Mint Farm plant, even though the facility is not expected to provide energy cost benefits to customers during the rate year. Even under my adjustment PSE’s customers will pay significantly more for energy during the rate year than if PSE had not acquired the Mint Farm plant. However, because in the long-run ownership of Mint Farm should benefit customers, I am recommending some cost recovery be allowed in the case. PSE has the opportunity to demonstrate that it is entitled to a full equity return on its Mint Farm investment in a future general rate case proceeding if it can show the investment is necessary and proper at that time.

IV. MINT FARM DEFERRAL PETITION

Q: What is PSE's proposal regarding the deferral and recovery of costs of Mint Farm that have been incurred since the plant was acquired in December 2008?

A: PSE is requesting approval to defer fixed and variable costs of ownership of the Mint Farm facility beginning with the plant acquisition date of December 5, 2008, and ending with the effective date of new rates in this case.[39] The Company's is seeking authority for this deferral under provisions of the greenhouse gas emissions performance standard in RCW 80.80.060.[40] In the alternative, if the Commission determines that the Mint Farm facility is not eligible for deferral accounting under RCW 80.80.060(6), PSE is requesting that the Commission issue an accounting order authorizing deferral of Mint Farm costs.[41]

Q: Has PSE previously requested approval for deferral of costs of its Mint Farm facility?

A: Yes. On November 25, 2008, PSE filed a petition in Docket UE-082128 seeking approval to defer costs for the Mint Farm facility. On April 2, 2009, PSE, the Commission Staff, Public Counsel and the Industrial Customers of Northwest Utilities (ICNU) entered into a settlement agreement that provided for issues involving PSE's eligibility for Mint Farm deferrals with the amount and

[39] Exhibit No. JHS-1T, p. 67.
[40] Exhibit No. JHS-1T, p. 66.
[41] Exhibit No. JHS-1T, p. 66.

recoverability of such deferrals to be decided by the Commission in the current proceeding.[42]

Q: Please describe the major terms of PSE's Mint Farm deferral proposal.

A: PSE is proposing deferred accounting for both fixed and variable costs of the Mint Farm facility from the closing date of the acquisition until the effective date of new rates in this proceeding.[43] With regard to fixed costs, which include operation and maintenance expense, depreciation, insurance, taxes and cost of capital invested in rate base, the Company proposes to defer costs it incurs from the acquisition date of the plant through the effective date of rates in this case, which it estimates to be approximately $60.7 million.[44] The Company seeks to recover all deferred fixed costs, plus accrued interest at the 7% annual net of tax rate of return agreed to in the Partial Settlement of the Company's last base rate case.[45] PSE further proposes that the deferred amounts be amortized over three years, consistent with the treatment that was authorized for recovery of deferred costs of its Goldendale combined cycle plant.[46] The resultant requested annual fixed cost deferral is $20.99 million.[47]

Q: How is PSE proposing to treat deferred variable costs of the Mint Farm facility?

A: There are several aspects to PSE's proposed deferral of Mint Farm variable costs.

[42] Exhibit No. JHS-1T, p. 66.
[43] Exhibit No. JHS-1T, p. 67.
[44] Exhibit No. JHS 4.34E Mint Farm Deferral WP (workpaper), "Rate Year Fixed Costs" Tab.
[45] Exhibit No. JHS-1T, p. 73.
[46] Exhibit No. JHS-1T, p. 74.
[47] Exhibit No. JHS-10, p. 40.

First, PSE is requesting an exemption from the new resource recovery provisions as defined by Exhibit G of the Company's Power Cost Adjustment (PCA) mechanism so that it may defer and recover all components of the variable operating costs of the facility as defined under the PCA. The Company claims this exemption is necessary to assure that it is able to recover all variable costs of the Mint Farm facility.[48] In addition, PSE is proposing credits to the deferred Mint Farm variable costs to reflect the estimated cost of market purchases reflected in its existing baseline power cost rate, which would be displaced by Mint Farm energy.[49] PSE is further proposing that any PCA over-recoveries during the deferral period be used to offset the remaining deferred variable costs of Mint Farm after other credits have been applied.[50]

Q: What is the amount of the Mint Farm variable cost deferral requested by PSE in this case?

A: PSE has assumed that there will be no Mint Farm variable cost deferral since it expects such costs to be fully offset by the proposed credit for market power or the proposed credit for over-recovery of power costs in the PCA true-up.[51]

Q: **Is PSE's proposal to defer and recover fixed and variable costs of Mint Farm reasonable?**

A: No. PSE's proposal to defer and recover fixed and variable costs of its Mint Farm investment is unreasonable and unjustified for several reasons:

[48] Exhibit No. JHS-1T, pp. 69-70.
[49] Exhibit No. JHS-1T, p. 71.
[50] Exhibit No. JHS-1T, p. 72.
[51] Exhibit No. JHS-1T, p.57.

- As discussed earlier in my testimony, PSE's decision to acquire Mint Farm in December of 2008 was unnecessary and inappropriate due to the fact that there were available alternatives to Mint Farm that would have better matched PSE's needs and provided greater benefits to customers.

- PSE's Mint Farm deferral proposal is unreasonable because it would effectively circumvent the Company's obligation to support provisions of the PCA mechanism that provide for recovery of fixed and variable costs of new generating resources;

- PSE's deferral proposal should be disallowed because Mint Farm does not appear to meet the minimum 60% capacity factor standard to qualify for deferred accounting as a baseload generating unit under RCW 80.80.60; and

- RCW 80.80.60(6) appears to limit deferred accounting to fixed costs of the Mint Farm investment, "including operation and maintenance costs, depreciation, taxes, and the cost of invested capital." Therefore, at minimum, PSE's request for deferred accounting for variable costs of Mint Farm should be disallowed.

Q: How is PSE's deferral proposal inconsistent with the Company's obligation to support the terms and conditions of the PCA mechanism?

A: As one of the Executing Parties to the PCA settlement agreement (PCA Agreement) in Docket Nos. UE-011570 and UG-011571, PSE agreed to the terms of the PCA Agreement.[52] As defined in paragraph 2 of the PCA Agreement, the purpose of the PCA mechanism is to account for differences in PSE's modified actual power costs relative to a power cost baseline. The PCA mechanism is specifically designed to provide for recovery of costs of new generating resources such as Mint Farm, either through the New Resource Adjustment described in

[52] Exhibit No. SN-6.

paragraph 7 and Exhibit G of the agreement, or through the PCORC mechanism described in paragraph 8 of the agreement.[53]

Q: Is there any reason why PSE could not use the PCORC provision of the PCA mechanism to expedite its recovery of costs of the Mint Farm facility until the plant could be reflected in its base rates?

A: No. The Commission has recently reaffirmed the reasonableness of the PCORC and the PCA mechanism as means for recovery of costs of new power supply resources.[54] PSE could easily have filed a PCORC application to recover fixed and variable costs after it made its decision to acquire the facility.

Q: Is there any reason why PSE could not have used the New Resource Adjustment provision of the PCA mechanism to expedite its recovery of variable costs of the Mint Farm facility until such costs could be fully reflected in the Company's baseline power rate?

A: No. Under the New Resource Adjustment specified in Exhibit G of the PCA, PSE can recover actual PCA variable costs of Mint Farm up to the Company's existing baseline power rate of $62.84/MWh.[55] Through September of 2009, the actual PCA variable costs of the Mint Farm facility have been **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX**[End Confidential]** which it has requested to defer through the New Resource

[53] Exhibit No. SN-6.
[54] *See*, Consolidated Docket Nos. UE-072300 and UG-072301, Order 13.
[55] Exhibit No. SN-6.

Adjustment provision of the PCA.[56] For these reasons, PSE's request to seek recovery of Mint Farm costs through a deferral mechanism rather than through the PCA new resource recovery provisions is inappropriate and should be disallowed.

Q: Has PSE cited any regulatory precedent to support its request for deferred accounting for variable production costs of its Mint Farm facility?

A: No. In fact, PSE's own internal assessment of the proposed deferred accounting request for Mint Farm concluded **[Begin Highly Confidential]** XXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXX **[End Highly Confidential]**[57]

Q: What are the basic requirements to qualify for deferred accounting as a baseload generating unit under RCW 80.80.60?

A: There appear to be two basic requirements which PSE must meet to demonstrate that Mint Farm qualifies for deferred accounting as a baseload electric generating unit under RCW 80.80.60(6).

- PSE must demonstrate that the Mint Farm facility was "designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent" in order to meet the "baseload electric generation" definition under RCW 80.80.010(4).
- PSE must demonstrate that the Mint Farm facility is "needed and appropriate", as specified under RCW 80.80.60(5).

As discussed earlier in my testimony, Mint Farm was not needed to meet PSE system capacity requirements until 2011, and the plant was not an appropriate

[56] *See*, PSE's Confidential Second Supplemental Response to WUTC Staff Data Request No. 023; PSE’s Response to WUTC Staff Data Request No. 033.
[57] Exhibit No. RG-7HC, p. 46.

resource because PSE's economic analysis of bids from its 2008 RFP indicated that **[Begin Highly Confidential]** XXXXXXXXXXX **[End Highly Confidential]** was expected to provide more than double the economic benefits forecasted for Mint Farm.

Q: Is there any evidence that indicates PSE intends or intended to operate Mint Farm at an annualized capacity factor of at least 60%?

A: No. PSE's forecasts of Mint Farm capacity factor performance have been consistently lower than the minimum 60% annual capacity factor level both before and after the decision to acquire the plant was made. For example:

- PSE's Phase II analysis of the Mint Farm bid projected a 20-year average capacity factor of 25% for the plant; [58]
- PSE's Company's August 4, 2008 presentation to the board of directors which supported the decision to acquire the plant forecasted that Mint Farm forecasted a 31% average capacity factor for Mint Farm.[59]
- PSE's original Aurora rate year power forecast for this case indicated an annualized average capacity factor of 40% for Mint Farm;[60]
- PSE's updated Aurora rate year power forecast for this case indicated an annualized average capacity factor of approximately 45% for Mint Farm.[61]

Based on the above evidence, Mint Farm does not appear to meet the minimum 60% capacity factor standard in order to qualify for deferred cost recovery under RCW 80.80.60.

Q: Are there any other reasons why PSE's Mint Farm deferral proposal should be disallowed?

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[58] Exhibit No. RJ-1HCT, p. 29.
[59] Exhibit No. RJ-HCT, p. 29.
[60] Exhibit No. RJ-HCT, p. 29.
[61] Exhibit No. DEM-11.

A: Yes. To date, the Mint Farm facility has not produced any **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXX. **[End Confidential]**[62] Due to the fact that Mint Farm actually **[Begin Confidential]** XXX **[End Confidential]** energy costs on PSE's system and is presently not needed for capacity purposes, the Company's request to defer and recover fixed costs of the facility including a return on the plant investment is unjustified.

Q: Why is the cost of energy from Mint Farm significantly higher than the market price of purchased energy available to PSE?

A: In addition to natural gas commodity costs, the cost of energy produced by Mint Farm includes approximately $8.8 million per year of fixed gas transportation charges plus $5.3 million per year of transmission wheeling charges. This means that the total cost of energy by Mint Farm during the rate year is forecasted to be approximately $57/MWh, which is approximately **[Begin Confidential]** XXX XXX **[End Confidential]** than PSE's forecasted average price of on-peak market energy purchases during the rate year.[63] Similarly, Mint Farm **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXX**[End Confidential]**[64]

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[62] Exhibit No. SN-7C.
[63] Exhibit No. SN-7C.
[64] PSE's Response to WUTC Staff Data Request Nos. 023, WUTC 033 and 165, Attachment A.

Q: Please summarize your conclusions and recommendations regarding PSE's proposal to defer and recover Mint Farm costs.

A: PSE's proposal to defer and recover Mint Farm fixed and variable costs is unreasonable and inconsistent with the Company's obligation under the PCA Settlement Agreement and PCA mechanism, which include two separate mechanisms (i.e., PCORC filings and the New Resource Adjustment under Exhibit G of the PCA) for recovering costs of new resources such as Mint Farm. Moreover, Mint Farm has not **[Begin Confidential]** XXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXX **[End Confidential]** which might otherwise justify the deferral and recovery of Mint Farm fixed costs. Finally, Mint Farm does not appear to meet the requirements to qualify for deferred accounting under RCW 80.80.60(6). For these reasons, I recommend that PSE's request to defer and recover fixed and variable costs of the Mint Farm facility incurred from the date of acquisition of the plant through the effective date of new rates approved in this case be disallowed, but that the Company be allowed to recover PCA variable costs of the Mint Farm facility under the New Resource Adjustment provision of the PCA. Public Counsel witness James Dittmer addresses the adjustments to PSE's revenue requirement to reflect my recommended disallowance on this issue in his direct testimony.

Q: Will PSE's PCA cost recoveries during the proposed deferral period need to be adjusted under your recommendation?

A: Yes. Under PSE's deferral proposal, the Company has recorded the cost of all energy produced by Mint Farm at a proxy rate based on the estimated cost of market purchases used in setting its existing baseline power rate since the plant was acquired in December of 2008. Under my recommendation, PSE's PCA cost recoveries for the proposed deferral period will need to be adjusted to eliminate PSE's proxy charges for Mint Farm and to instead reflect the lower of the actual variable costs of Mint Farm, or the existing baseline rate, as provided under the New Resource Adjustment as specified in Exhibit G of the PCA Agreement.

V. UPDATED RATE YEAR POWER COST FORECAST

Q: What is PSE's updated rate year power cost forecast?

A: PSE's updated rate year power cost forecast is $1.134 billion, which represents a $50.1 million decrease in costs from the original rate year forecast in this case.[65]

Q: What are the primary factors contributing to the $50.1 million decrease in PSE's updated rate year power forecast?

A: Approximately $41.7 million (~83%) of the decrease in the updated forecast is attributable to the forecasted 932,282 MWh load reduction when compared to the original forecast.[66] Other major factors contributing to the reduction in power costs in the updated forecast are a $10 million reduction due to the elimination of a Colstrip maintenance outage from the rate year, a $4.0 million reduction due to a revised forecast of BPA wheeling charges, and a $3.1 million reduction due to PSE's updated gas price forecast.[67] The reductions in PSE's updated power cost forecast were offset

[65] Exhibit No. DEM-9CT, pp. 1-2.
[66] Exhibit No. DEM-9CT, p. 4.
[67] Exhibit No. DEM-9CT, p.2.

Q: How does PSE's proposed updated rate year power forecast impact the baseline Power Cost Rate use in the PSC mechanism?

A: The updated baseline Power Cost Rate is $67.193 per MWh, which is approximately 0.4% higher than the baseline rate of $66.911 per MWh included in PSE's original filing. The updated baseline rate is approximately 7% higher than PSE's existing baseline rate of $62.84 per MWh which was approved in the Company's last base rate case.

Q: Have you reviewed the details underlying PSE's updated power cost forecast?

A: Yes. I reviewed PSE's filed workpapers and schedules supporting the updated forecast filed on September 28, 2009, and conducted discovery on various aspects of the forecast. PSE's power supply forecasting process is relatively complex and involves hundreds of assumptions and the use of multiple models. Because PSE's updated rate year power forecast was filed with the Commission on September 28, 2009, my opportunity for discovery and analysis of the updated Aurora analysis and other power cost changes in the updated forecast was limited which is not ideal in light of the complexity of PSE's power forecasting process. However, I have identified certain aspects of PSE's updated forecast which appear to unreasonably overstate rate year power costs, including:

- The hydro generation forecast used for PSE's updated rate year power cost forecast is based on the average level of hydro generation during the 50-year period 1929-1978, while more recent information indicates a higher level of hydro generation is appropriate for the rate year forecast;

- PSE's off-system sales forecast is far below historical sales levels and serves to understate revenues from market sales that should be available to reduce native system power costs during the rate year; and

- The proposed $46.2 million mark to market (MTM) gas price adjustment included in PSE's updated rate year power cost forecast will tend to lead to future over-recoveries of power costs.

Q: What were the major changes from PSE's original filed power supply forecast to the updated forecast?

A: Aside from the 932,382 MWh reduction in total system load and the elimination of a Colstrip rate year outage, the primary changes from the original forecast to the updated forecast include a $0.38/MMBtu (6%) reduction in gas prices, a 1.2 million MWh reduction in the volume of market purchases, and a 449,870 MWh increase in the volume of gas-fired generation. Normally, each of these changes would be expected to result in lower average power costs for PSE's system. For example, under economic dispatch principles, the reduction in system load should result in higher marginal cost resources being dispatched less in the updated forecast, thereby lowering average power costs. Similarly, to the extent the forecasted load reduction is reflective of conditions in the surrounding regional market, there should also be a reduction in the cost of market energy purchases. The increase in Colstrip generation, which is among the lowest cost sources of energy on PSE's system (after hydro and wind), should lower PSE's system average energy cost in the updated forecast. Furthermore, the 6% decrease in forecasted natural gas prices in the updated forecast should result in lower average gas-fired generation and market purchase costs when compared to PSE's original power forecast.

Q: Does PSE's updated power cost forecast reasonably reflect the above changes?

A: I did not have access to the Aurora model software in order to verify that PSE's modeling analyses were reasonable and that the model is accurately simulating the operations and dispatch of PSE's generating resources and energy prices from the regional market. However, the overall average power cost from the updated Aurora results provided by PSE (~$29.84 per MWh) is approximately 4.6% lower than the average cost of energy from PSE's original filed Aurora forecast in this case.[68] This reduction is generally consistent with the trend in results I would expect given the changes in input assumptions from the original filing to the updated forecast.

Q: If the average cost of energy from PSE's updated Aurora forecast is lower than the original forecast, why is the overall updated power cost rate slightly higher than the rate in PSE's original forecast?

A: The overall power cost rate appears to be higher even though the average costs from Aurora were lower for several reasons. First, because the updated sales forecasts is actually lower than the test year period sales, the production factor adjustment under the updated forecast actually increases the updated forecast costs by 1.2% (the new production factor). In addition, the production costs determined by the Aurora Model represent only approximately 70% of the total

[68] Exhibit No. DEM-11C, Attachment 2.

system power costs included in the power cost rate. A number of other power supply costs which are forecasted outside of the Aurora model increased from the original forecast to PSE's updated forecast.

Q: Please explain your concerns regarding PSE's hydro generation forecast.

A: PSE has used the average hydro generation level for the 50-year period 1929-1978 as the basis for its rate year hydro forecast in this case. The Company indicates that it has used this period rather than a more recent period because this approach was the recommended by the WUTC Staff in the Company's 2004 general rate case.[69] However, the average annual hydro generation level for the Mid-C hydro contacts for the most recent 50-year period for which information is available (i.e., 1949-1998) is significantly higher than the level experienced during the 1929-1978 period.[70] Given the significant increase reflected in the more recent 50-year average hydro generation data for the Mid-C hydro contracts, I am concerned that using the 1929-1978 period for forecasting PSE's hydro generation levels will result in the under-forecast of rate year hydro generation levels and therefore lead to significant over-recovery of power supply costs by PSE.

Q: What is your recommendation on this issue?

A: I recommend that PSE's rate year hydro generation forecast be revised to reflect the average hydro generation levels over the 50-year period 1949-1998. This recommendation will serve to increase PSE's rate year hydro generation forecast for the Mid-C hydro contracts by **[Begin Confidential]** XXXXXXXX. **[End**

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[69] PSE's Response to Public Counsel Data Request No. 474.

Confidential][71] To calculate the reduction in rate year energy costs resulting from this adjustment, I have used PSE's forecasted average cost of market energy purchases during the rate year, which was **[Begin Confidential]** XXXXXXXX. **[End Confidential]**[72] My recommended adjustment for this issue reduces PSE's rate year power costs by $5,569,835. [73]

Q: Why are you proposing an adjustment only for the Mid-C hydro contract purchase?

A: At the time I prepared my testimony I had not obtained the most recent hydro generation data for Puget's hydro generation projects. After I receive and analyze the information for Puget's hydro generation projects, I will supplement my testimony as needed to reflect the impact of using the more recent historical 50-year hydro generation levels, consistent with my adjustment for the Mid-C hdro purchases.

Q: Would you please explain the problem regarding PSE's rate year forecast of off-system sales?

A: As shown in Table 1, the average level of OSS made by PSE over the last five years is approximately **[Begin Confidential]** XXXX **[End Confidential]** of the level of OSS forecasted by PSE during the rate year.

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[70] Exhibit No. SN-8C.
[71] Exhibit No. SN-8C.
[72] Exhibit No. SN-8C.
[73] Exhibit No. SN-8C.

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There is no reasonable explanation as to why OSS during the rate year should be so much lower than the historical OSS made by PSE in recent years. In fact, with the addition of Mint Farm and the Wild Horse expansion project, PSE should be expected to have more low cost energy on its system and therefore a higher volume of OSS in the rate year.

Q: Have PSE's forecasts of OSS in recent past proceedings also been lower than actual OSS?

A: Yes. As shown in Table 2, PSE has consistently under-forecasted the volume of OSS by a large amount when setting its baseline power costs in past rate cases.

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Q: How does PSE's under-forecasting of OSS impact power cost recoveries under the PCA mechanism?

A: PSE makes OSS when it is economically beneficial to make such sales, and the revenues from OSS serve to directly reduce native system power costs under the PCA mechanism. Accordingly, to the extent PSE's forecast of OSS is understated, as it has been in past cases, the Company's baseline power rate will be overstated and will therefore tend to over-recover actual power costs during the rate year period.

Q: Does the consistent under-forecast of OSS presented in Table 2 raise any other concerns regarding PSE's baseline power forecast in this case?

A: Yes. PSE's forecast of OSS is developed using the Aurora production cost model. It appears from the results presented in Table 2 that the Aurora model is not accurately simulating the operations of PSE's system and regional market prices. This apparent problem, which affects the level and costs of both market purchases and market sales, raises a serious concern since the majority of PSE's rate year baseline power costs are derived from the Aurora model dispatch analysis.

Q: What is your recommendation to address this issue?

A: I recommend that PSE's baseline power cost forecast for the rate year be adjusted to reflect the average annual volume of OSS made by PSE over the last 5 calendar years **[Begin Confidential]** XXXXXXXXXXX **[End Confidential]** as presented in Table 1. Although the actual level of rate year OSS is likely to be even higher than the historical average due to the addition of the Mint Farm and Wild Horse expansion projects, I believe that the use of a 5-year average of OSS for forecasting the volume of rate year OSS is reasonable.

I further recommend that PSE's updated rate year power cost forecast be reduced to reflect a credit of $5,141,295, which I derived by multiplying **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. **[End Confidential]**[74] My recommended OSS margin, which is equivalent to approximately **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXX, XXXXXXXXXXXXXXXXXXXXXXXX **[End Confidential]** was estimated

[74] Exhibit No. SN-9C.

because PSE indicates that it does not account for margins associated with OSS.[75] I recommend that in future cases PSE be required to account for actual OSS revenues and margins and present such information to support the reasonableness of forecasted OSS revenues in its power cost forecasts.

Q: What is your concern regarding PSE's proposed rate year gas contracts Mark-to-Market (MTM) adjustment?

A: PSE is proposing to embed a $46.2 million gas contract MTM adjustment in its baseline power cost rate in this case.[76] This amount represents approximately 10% of PSE's total forecasted rate year gas costs which means that the costs recovered by PSE though its new power cost rate will be approximately 10% higher than the Company's current forecast of rate year market gas prices. My concern is that if market gas prices are lower than presently forecasted by PSE during the rate year, or if PSE maintains its baseline power rate beyond the rate year period, the MTM premium embedded in the baseline rate could result in significant power cost over-charges to customers. Under PSE's existing PCA mechanism, up to $20 million per year of any over-recovery attributable to this factor would be retained by the Company.

Q: What is your recommendation to address this problem?

A: I recommend that the MTM amount reflected in PSE's proposed baseline power cost rate be eliminated after 12 months since there is no basis for including this adjustment beyond the rate year period. This would be accomplished by

[75] PSE's Response to Public Counsel Data Request No. 482.
[76] Exhibit No. DEM-11HC, Attachment 2 to Supplemental Direct.

implementing a MTM credit factor of $0.00201 per kWh effective April 1, 2011, which is the date immediately following the end of the rate year in this case.[77] This adjustment has no impact on the rates proposed in this case, but would affect PSE's power cost charges beyond the rate year period. I recommend that this MTM credit factor would be implemented only if PSE does not modify its baseline power rate before April 1, 2011.

Q: Do you have any alternative proposals to address your concerns regarding the abnormal levels of hydro generation, off-system sales and gas contract MTM amounts included in PSE's baseline power forecast?

A: Yes. My review of PSE's existing PCA mechanism indicates that there is no provision for the Commission or customers to initiate reductions to the Company's baseline power cost rate in the event that there are significant market events that justify such changes. While PSE has the right to modify its baseline power cost rate if costs go up, the Company would have little incentive under the PCA to modify its baseline power rate when market prices go down, as has occurred over the last nine months. This lack of symmetry in the rights of parties to initiate changes to power rates under the PCA mechanism may not have been a major concern when the mechanism was implemented, since at that time, gas-fired generation represented a relatively small amount of the Company's total system energy costs. However, as shown in Table 3, from 2006 until the rate year in this case, the volume of gas-fired generation on PSE's system has increased by 350% and now represents approximately 15% of the Company's total energy

[77] Exhibit No. SN-10.

supply. It is likely that the volume of gas-fired generation on PSE's system will continue to increase in the future.

Table 3
PSE System Gas-Fired Generation

	MWH
2004	799,032
2005	813,018
2006	722,130
2007	1,310,312
2008	2,269,225
4/10-3/11 RYR	3,271,244

Source is PSE's response to PC DR No. 488.

This growth in gas-fired generation will make PSE's fuel costs more volatile and difficult to predict in the future. My concern is that the PCA mechanism creates a financial disincentive for PSE to adjust its power cost rates downward when there are significant reductions in market prices for natural gas. Given these facts, and with due consideration given to the economic hardship experienced by many customers over the last year, I recommend that the Commission consider establishing a trigger mechanism that would require PSE to petition the Commission to reduce its power cost rate at any time that its natural gas costs drop by 15% or more below the forecasted price level used in setting its approved power cost rate.

VI. SALE OF RENEWABLE ENERGY CREDITS

Q: What are Renewable Energy Credits?

A: Washington's Energy Independence Act defines Renewable Energy Credits (REC) under Section RCW 19.285.030 as:

> . . .a tradable certificate of proof of at least one megawatt-hour of an eligible renewable resource where the generation facility is not powered by fresh water, the certificate includes all of the nonpower attributes associated with that one megawatt-hour of electricity, and the certificate is verified by a renewable energy credit tracking system selected by the department.

Q: What is the issue regarding PSE's sale of RECs in this case?

A: In late 2008 and the spring of 2009, PSE entered into agreements with Southern California Edison Company (SC) and Pacific Gas and Electric Company (PG&E) to sell energy and RECs produced from PSE's Wild Horse and Hopkins Ridge wind generation facilities over the 2009-2015 period. PSE states in its direct testimony that these transactions were made in conjunction with settlement of legal claims related to power sales by PSE into the California energy market in 2001. [78]

Q: What are the expected revenues from PSE's sale of RECs under its contracts with SCE and PG&E?

A: PSE estimates total revenues of approximately **[Begin Highly Confidential]** XX XXXX **[End Highly Confidential]** from sale of RECs under its contracts with SCE and PG&E.[79]

Q: What portion of these REC sales revenues are expected to occur during the rate year in this case?

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[78] Exhibit No. EMM-1CT, p. 35.
[79] Exhibit No. SN-11HC.

A: Based on PSE's updated power cost forecast, the Company's **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXX **[End Confidential]** during the rate year.[80] Based upon the **[Begin Highly Confidential]** XXXXXXXXXXXXXXXXXXXXXXXX, XXXXXX **[End Highly Confidential]** this would produce total REC sales revenues of approximately $51,057,512 during the rate year. [81]

Q: What is PSE's proposed treatment of revenues from sales of RECs to SCE and PG&E?

A: The Company indicated in its direct testimony in this case that it would consider using the REC sale revenues as a means to mitigate rate impacts of its proposed rate increase on customers.[82] However, on October 7, 2009, PSE filed an amended petition in Docket UE-070725 requesting that the Commission approve the ratemaking treatment of REC sales revenues in that proceeding. In that petition, the Company is requesting that it be allowed to retain $21 million of the REC sale proceeds to offset remaining litigation claims resulting from a dispute regarding payment for power sales it made to SCE, PG&E and certain other California utilities during 2000-2001. The Company further proposes to allocate up to $20 million of the remaining REC proceeds to fund low-income renewable energy projects, with the remainder of such revenues to benefit customers by offsetting regulatory assets included in the Company's base rates. PSE's petition in Docket UE-070725 describes this proposal as follows:

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[80] Exhibit No. DEM-11C.
[81] Exhibit No. SN-11HC.
[82] Exhibit No. EMM-1CT, p.33.

> As cash is received from the REC sales, the amount remaining after allocation to low income and the California Receivable would be allocated to the storm damage balance. If the total balance is paid off any additional REC Proceeds would be deferred in a regulatory liability account and would be addressed in the Company's next regulatory filing that adjusts electric general tariffs.

Q: Are you aware of any reason why it is necessary to defer consideration of the REC sales revenues until PSE's next general rate case?

A: No. The REC sales contracts with SCE and PG&E have now been approved and the revenues under these contracts are already being collected by PSE, and, therefore, are known and measurable. Moreover, the forecasted generation and costs from the Hopkins Ridge and Wild Horse wind generation projects, from which these RECs will be supplied, are included in PSE's rate year power cost forecast in this case. To the extent that such costs are sufficiently certain to be collected in PSE's new base rates, the REC revenues that PSE will receive from sales of RECs supplied by the Hopkins Ridge and Wild Horse facilities are also sufficiently certain to be reflected as a credit to base rates.

Q: Are PSE's retail customers paying all costs of the Hopkins Ridge and Wild Horse facilities from which RECs will be supplied under PSE's contracts with SCE and PG&E?

A: Yes. Based on PSE's estimates, the total annual revenue requirement for the Hopkins Ridge and Wild Horse wind projects collected through retail rates in this case is approximately $120 million.[83]

[83] PSE's Responses to Public Counsel Data Requests Nos. 484 and 485.

Q: What is your recommendation regarding the ratemaking treatment of revenues from PSE's sales of RECs from its Hopkins Ridge and Wild Horse wind projects?

A: PSE's proposal to defer consideration of REC sales revenues until the Company's next general rate case is unreasonable. It is my understanding that the Commission has decided that PSE's proposals to retain $21 million of such revenues to offset unpaid litigation claims related to past power sales to California utilities and to allocate up to $20 million of the REC sale proceeds to fund energy efficiency programs for low income customers should be decided in Docket No. UE-070725. There will be adequate REC sales revenues to both address PSE's proposals in that docket, if the Commission decides they are proper, and to help mitigate the proposed rate increase in this case. It is not necessary or appropriate to wait until PSE's next general rate case to provide customer credits for REC sales revenues that are known and measurable in the rate year in this case. Accordingly, I recommend that the $51,057,512 of estimated REC sales revenues during the rate year be applied as credits to reduce PSE's approved baseline power cost rate in this case. These credits will help mitigate the $153.6 million base rate increase requested by PSE in this case, as suggested in PSE's original direct testimony, and also will help offset the significant costs of wind generation projects that are paid entirely by PSE's retail customers.

Q: Do you have other recommendations regarding the Commission's oversight of PSE's REC sales in the future?

A: Yes. It would be beneficial for the Commission to increase oversight of PSE activities related to the sales of RECs to ensure that the benefits of such transactions are maximized for customers who are funding the costs of the facilities from which these RECs are supplied. A recently filed settlement agreement in Docket No. UE-090205, PacifiCorp's pending general rate case, establishes terms for reporting and monitoring of REC sales activities by the utility on an ongoing basis.[84] I recommend that the Commission adopt similar reporting and monitoring requirements for PSE to ensure that information is available to monitor PSE's REC sales and to help determine whether customer benefits from such sales are being maximized.

VII. PSE'S WIND GENERATION DEVELOPMENT STRATEGY

Q: What is PSE's development strategy for wind generation resources?

A: In late 2006, PSE created a development strategy to address difficulties it was experiencing at the time in acquiring wind generation and other renewable resources.[85] Under this new strategy, PSE planned to become involved early in the process of development of wind and other renewable energy resources, rather than purchasing operating projects or mature development rights from other parties.[86] At the time it entered into this new strategy, there was high demand for new wind generation projects within the industry, and PSE felt that by becoming involved in the development process at an early stage, it could reduce development risk and lower costs by avoiding project development fees. In

[84] *See*, Settlement Stipulation from Docket No. UE-090205.
[85] Exhibit No. RG-1HCT, p. 63.
[86] Exhibit No. RG-1HCT, p. 63.

conjunction with this new wind development strategy, in November of 2008, PSE entered into a Joint Development Agreement (JDA) with Renewable Energy Systems America (RES) to acquire, develop and own new wind generation projects.[87] As part of the RES JDA, PSE has announced plans to develop approximately **[Begin Highly Confidential]** XXXXXXX **[End Highly Confidential]** of new wind generation projects at four separate sites which it collectively refers to as the Lower Snake River Projects.[88] The Company has indicated that it plans to construct the first 250 MW of the Lower Snake River Project in 2011. [89]

Q: Is PSE seeking Commission approval of its development strategy, the RES JDA, or development of new wind projects pursuant to the JDA in this case?

A: No.[90] The Company states that the purpose of its testimony regarding this issue is to update the Commission and parties regarding the progress it is making in implementing its development strategy.

Q: Does PSE currently have sufficient wind generation resources to meet future Renewable Portfolio Standard (RPS) requirements on its system?

A: Yes. PSE currently owns the Hopkins Ridge and Wild Horse wind projects, including the soon to be completed Wild Horse Expansion project. The Company also has a contract to purchase 50 MW from the Klondike III wind farm. Together, these existing wind resources provide approximately 479 MW of

[87] Exhibit No. RG-1HCT, pp. 91-92.
[88] Exhibit No. RG-1HCT, p. 63.
[89] Exhibit No. RG-1HCT, p. 99.
[90] Exhibit No. RG-1HCT, p. 91.

installed capacity, which is sufficient to allow PSE to meet the Washington State RPS requirement to supply 3% of its total system load with renewable resources beginning in 2012 and through 2015. [91]

Q: Why is PSE seeking to develop 250 mw of new wind generation by 2011 under the RES JDA if it already has sufficient wind capacity to meet Washington's RPS requirements through 2015?

A: PSE established a corporate goal of supplying 10% of its system load with renewable energy by 2013.[92] The Company states that it is committed to meeting this corporate goal, if economically feasible and necessary to meet load energy requirements, in the stipulation agreement for its 2007 Merger proceeding, WUTC Docket No. U-072375.[93]

Q: Would it be prudent for PSE to proceed with the development or acquisition of new wind generation capacity at this time?

A: The determination of prudence of generating investments depends on the cost and need for projects as well as evaluated benefits when compared to available alternatives. It is conceivable that PSE could justify the purchase or ownership of 250 MW of new wind generation by 2011; however, if the reported costs of the Company's Wild Horse Expansion project are indicative of costs that can be expected for future wind projects, it is unlikely that a new wind project would be economically or otherwise justified in 2011.

Q: What is the estimated cost of PSE's Wild Horse expansion project?

[91] Exhibit No. RG-1HCT, p. 97.
[92] Exhibit No. RG-1HCT, p. 97.
[93] PSE's Response to Public Counsel Data Request No. 523 and WUTC Staff Data Request No. 176.

A: The estimated capital cost of the 44 MW Wild Horse wind expansion project is approximately $102.5 million ($2,330 per kW).[94] Based on PSE's estimates of the revenue requirement for the project, the average cost of energy produced from the Wild Horse expansion project in its first year of operation would be nearly $169 per MWh after production tax credits.[95] PSE estimates that 20-year levelized cost of energy from the Wild Horse expansion project will be approximately $124 per MWh. These costs of wind energy from the Wild Horse expansion project are three to four times the forecasted cost of market energy purchases during the rate year.

Q: Why is it appropriate to compare costs of wind generation projects to market energy prices?

A: Wind generation projects are essentially non-dispatchable, non-firm energy resources, as are most market energy purchases. It is not appropriate to compare costs of wind generation projects to other new generation alternatives since wind generation projects are not firm resources. For these reasons, it is inappropriate to compare costs of wind generation projects to the all-in cost of other new generating resource alternatives when evaluating the economic feasibility of wind generation options.

Q: What does the cost of energy from the Wild Horse expansion project suggest regarding PSE's plan to develop the first 250 MW of the Lower Snake River Wind project by 2011?

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[94] Exhibit No. RG-1HCT, p. 84.
[95] PSE's Response to Public Counsel Data Request No. 484.

A: Based on current planning estimates, and the construction cost of the Wild Horse expansion project, the total capital cost of the Lower Snake River Wind projects which PSE plans to develop under the RES JDA is likely to be more than $3 billion. This amount of new investment would be nearly double PSE's current generation rate base. Unless the total cost of energy delivered from these new wind projects proves to be far lower than the cost of energy from the Wild Horse expansion project, it seems unlikely that any new investment in the Lower Snake River wind projects would be prudent before such capacity is needed to meet RPS requirements, which is currently projected to be 2016 or later. Moreover, PSE is under no obligation to meet its corporate of goal of supplying 10% of its system load with renewable energy by 2013 unless new wind additions are economically feasible, necessary to meet PSE's system load requirements and beneficial to customers.

Q: Please summarize your conclusions regarding PSE's announced development strategy for wind generation.

A: Wind generation projects are non-dispatchable, non-firm energy resources, and the cost of energy delivered from PSE's new wind projects is approximately 3 to 4 times the current market price of purchased energy. Given these facts, it does not appear it would be prudent for PSE to proceed with the development of any new wind generation projects until such projects are needed to meet the Company's RPS requirements, or are otherwise justified by economic benefits to customers when compared to available resource alternatives.

Q: Do you have a specific recommendation at this time regarding PSE's announced wind development strategy?

A. No. As I observed earlier, PSE has stated it is not requesting approval or a prudence determination for any specific wind project, or for its overall strategy for wind development. My testimony is a response to the "update" provided by PSE in this case. I am suggesting major issues that may need to be considered in this area. It is important that PSE not be allowed to argue in a future proceeding that parties (or the Commission) were informed of and did not object to the Company's announced wind development strategy. Whether or not it addresses the merits of the planning, the Commission may wish to state in its order in this case that no prudence finding was requested, no showing made, and therefore no decision has been made to pre-approve any aspect of PSE's wind development plans.

Q: Does that conclude your testimony?

A: Yes.