EXHIBIT NO. ___(WJE-1HCT)
DOCKET NO. UE-09____/UG-09____
2009 PSE GENERAL RATE CASE
WITNESS: W. JAMES ELSEA

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-09____ Docket No. UG-09____

PREFILED DIRECT TESTIMONY (HIGHLY CONFIDENTIAL) OF
W. JAMES ELSEA
ON BEHALF OF PUGET SOUND ENERGY, INC.

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MAY 8, 2009

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (HIGHLY CONFIDENTIAL) OF W. JAMES ELSEA

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is W. James Elsea. My business address is 10885 N.E. Fourth Street Bellevue, WA 98004. I am the Financial Analysis Manager of Energy Resources for Puget Sound Energy, Inc. ("PSE").

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

A. Yes, I have. It is Exhibit No. ___(WJE-2).

Q. What are your duties as Financial Analysis Manager of Energy Resources for PSE?

A. My present responsibilities include review of and participation in analysis of individual power resources and portfolios of power resources for PSE's Least Cost Plan, Integrated Resource Plan, and resource acquisition processes.

Q. What is the nature of your direct testimony in this proceeding?

A. My direct testimony describes the modeling tools and quantitative analyses utilized by PSE to evaluate the various resource alternatives presented for cost recovery in this case. This direct testimony describes PSE's quantitative models and assumptions, and quantitative analysis process undertaken in Phase I and Phase II of its 2008 All Generation Sources Request for Proposals (the "2008 RFP"). Additionally, I describe the results of qualitative and quantitative review of the 2008 RFP that led to the selection of the "Final Short List".

My direct testimony further describes the quantitative analysis of the following resources acquired by PSE:

(i) the 310 Megawatt ("MW") Mint Farm Energy Center from Wayzata Investment Partners;

(ii) a 75 MW four-year winter power purchase agreement with Barclays Bank PLC;

(iii) the expansion of the Wild Horse Wind Project to add 44 MW of capacity to the facility;

(iv) a five-year power purchase agreement with Puget Sound Hydro LLC;

(v) a five-year power purchase agreement with Qualco Energy, LLC;

(vi) a four-year and three-month power purchase agreement with Credit Suisse; and

(vii) the acquisition of the Fredonia Generating Units No. 3 and No. 4.

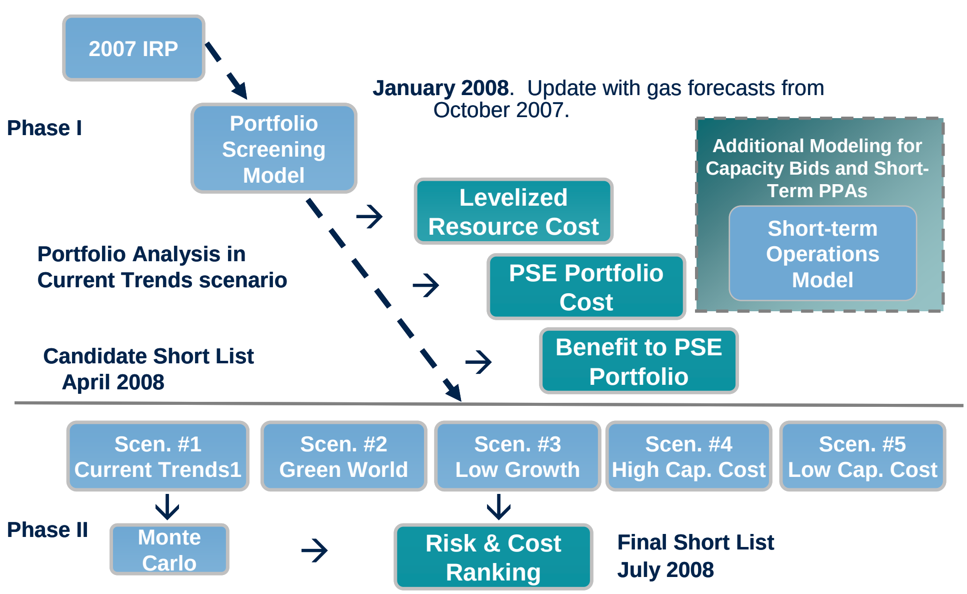
II. OVERVIEW OF PHASE I AND PHASE II OF THE 2008 RFP

A. <u>Overview of PSE's Resource Planning and Acquisition Models</u>

Q. Please describe the role of the quantitative analyses in PSE's acquisition process.

A. The quantitative analysis plays an integral part of the acquisition process by creating a basis to determine the lowest reasonable cost resources that meet the need for resources as established in PSE's 2007 Integrated Resource Plan (the "<u>2007 IRP</u>"). The quantitative analysis evaluates the cost of the resource alternatives and the potential variability of cost. Figure 1 below depicts the quantitative evaluation process for Phase I and Phase II of the 2008 RFP process.

Figure 1. PSE's Quantitative Evaluation Process



Q. What quantitative models did PSE use in evaluating potential resource alternatives?

A. PSE used three quantitative models in evaluating potential resource alternatives: (i) AURORA, (ii) the Portfolio Screening Model ("PSM"), and (iii) the KWI model. Please see Exhibit No. ___(RG-3HC) at pages 161–63 for a brief description of the AURORA, PSM, and KWI models.

Q. Did PSE update the projected need for resources as established by the 2007 IRP before the 2008 RFP?

A. Yes. PSE updated the projected need for resources as established by the 2007 IRP before the 2008 RFP, including but not limited to updates to PSE's current demand forecast and incorporating each new PSE resource and power purchase agreement ("PPA"). For example, PSE based the 2007 IRP projected need on the FY2006 demand forecast, before conservation. For the 2008 RFP, PSE updated to the FY2007 demand forecast, after conservation.

PSE also updated its resource supply to reflect recent developments. For example, NESCO defaulted on its PPA with PSE for the output of the Sumas Cogeneration Station after PSE published the 2007 IRP. PSE subsequently acquired two replacement PPAs and the Sumas Cogeneration Station itself, and PSE incorporated these two replacement PPAs into its resource supply.

Q. How does PSE define resource need?

A. Resource need is defined by both an energy requirement and by a capacity requirement that were both developed during the 2003 Least Cost Plan. The energy requirement is to have sufficient firm resources to meet the average energy load in each month and is expressed in average Megawatts ("aMW"). Energy need is the difference between average load and available firm energy resources. The capacity requirement is based on the 1 hour load to serve customers at a temperature of 13 degrees Fahrenheit. The capacity need is the difference between the 1-hour peak load and all available firm energy and capacity resources.

Q. What was the projected resource need for the 2008 RFP?

A. The projected energy need for resources for the 2008 RFP was approximately 150 aMW in January 2011. The projected energy need grows to 700 aMW in January 2012 and nearly 1,200 aMW in 2015. The 13 degrees Fahrenheit capacity requirement grows from over 200 MW in 2011 to 760 MW in 2012. Please see Exhibit No. ___(WJE-3) for a table that depicts PSE's monthly energy and capacity need, projected as of January 7, 2008.

Q. Does PSE rely solely on the quantitative analysis to determine which resources to acquire?

A. No. PSE does not rely solely on the quantitative analysis to determine which resources to acquire. PSE also performs qualitative analyses to determine the feasibility of each proposal. Please see the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), for a description of the qualitative analyses.

B. Overview of PSE's Quantitative Evaluation Process in Phase I of the 2008 RFP

Q. What is the purpose of PSE's quantitative evaluation process in Phase I of the 2008 RFP?

A. PSE's quantitative evaluation process in Phase I of the 2008 RFP screens out the highest cost and infeasible proposals. In doing so, PSE's quantitative team works closely with the other PSE working groups to evaluate the costs of the proposals.

Q. What quantitative models did PSE use in Phase I of the 2008 RFP?

A. In Phase I of the 2008 RFP, PSE used all the models mentioned above. PSE used AURORA V8.5 and the latest Western Electricity Coordinating Council ("WECC") database from EPIS, Inc., the developer of the AURORA model. The AURORA model generated power price inputs for the PSM. PSE screened each proposal in PSM that uses an hourly dispatch and calculation of end effects to evaluate the impact of the proposal on portfolio costs. PSE used the KWI model to assess the impact of shorter-term PPA on portfolio cost and risk.

Q. Did PSE update its quantitative models for Phase I of the 2008 RFP?

A. Yes. Before evaluating proposals solicited in the 2008 RFP, PSE updated the

Current Trends scenario in AURORA from the 2007 IRP to reflect then-recent natural gas price forwards and long-term forecasts. PSE also updated projected carbon costs and renewable portfolio standards to reflect current trends in federal, regional, and state policy.

Q. Did the updated Current Trends scenario in AURORA result in projected increases in electricity prices?

A. Yes. The updated Current Trends scenario in AURORA projected a 1.2% increase in levelized electricity prices at the Mid-Columbia hub as compared to the similar 2007 IRP scenario. Please see Exhibit No. ___(RG-3HC) at page 162 for a summary of projected electricity prices.

Q. Did PSE make any other updates to its quantitative models for Phase I of the 2008 RFP.

A. Yes. In addition to the above-described updates in AURORA, PSE updated the PSM Current Trends model to reflect (i) the above-described updated prices from AURORA, (ii) projected renewable energy credit costs, (iii) projected transmission costs, (iv) PSE's projected resource need, and (v) projected generic wind and gas capital costs. Please see Exhibit No. ___(WJE-4C) for a summary of the PSM updates to assumptions and model logic.

Q. What cost information did PSE consider in Phase I of the 2008 RFP?

A. In Phase I of the 2008 RFP, PSE evaluated the fixed and variable costs of the generation, including but not limited to capital costs, financing costs, fuel costs operation and maintenance costs, the costs to deliver fuel to the plant, the costs to transmit power from the point of receipt to PSE's system, and the costs of ancillary services required to support generation. PSE used its internal expertise for evaluating the cost of transmission services and delivery of fuel. For Phase I of the RFP, PSE used the operations and maintenance costs provided by bidders in their proposals.

Q. How did PSE compare proposals with differing technologies?

A. In screening proposals, PSE attempted to compare proposals on a consistent and fair basis that can be replicated. For each proposal, PSE developed estimates of future long-term electric transmission costs, natural gas transportation costs (if applicable), projected transaction costs, and insurance and property tax costs.

PSE's experience has been that transaction costs (e.g., costs of due diligence, legal fees) for ownership proposals are generally higher than transaction costs for PPA proposals. Therefore, PSE projected higher transaction costs for ownership proposals.

For insurance and property tax costs, PSE used its current insurance rates and property tax centrally assessed rates.

For wind proposals, PSE retained DNV Global Energy Concepts Inc. to perform high-level evaluation of the wind resource proposals that PSE received in the

2008 RFP to ensure all wind resource assessments were based on similar assumptions. Please see Exhibit No. ___(RG-4HC) for a copy of the Analysis of Wind Energy Proposals for 2008 RFP Evaluation prepared by DNV-GEC.

Q. Please describe the number of proposals evaluated in the 2008 RFP.

A. PSE began opening proposals in response to the 2008 RFP on February 29, 2008. PSE received 31 proposals (containing more than 100 offers) submitted by 25 different respondents. Please see Exhibit No. ___(RG-3HC) at page 6 for a summary of proposals by final type and at pages 33–35 for a list of the offers submitted in the 2008 RFP. In total, PSE evaluated 93 individual resource alternatives with the PSM in Phase I of the 2008 RFP.

Q. Did PSE consider any “unsolicited” proposals?

A. Yes. In addition to the 31 responses to the 2008 RFP, PSE evaluated additional proposals received outside the formal 2008 RFP process alongside the proposals received in the formal 2008 RFP process to determine the best resource options for PSE. Please see Exhibit No. ___(RG-3HC) at page 37 for a list of “unsolicited” proposals evaluated by PSE during the 2008 RFP.

Q. What were the results of the Phase I quantitative evaluation of resources?

A. For Phase I of the 2008 RFP, PSE developed a high, medium, and low ranking for each proposal, based on the resulting benefit cost ratio. Proposals with a benefit ratio greater than zero received a high rating. Proposals with a benefit ratio greater than -0.1 but less than or equal to zero, received a medium rating. Finally, proposals with a benefit ratio less than or equal to -0.1 received a low rating.

In addition to assigning a rating to each proposal based on the quantitative results, PSE assigned a subjective judgment rating about the quality of the data provided by bidders for use in deriving the quantitative results.

The following table summarizes the Phase I rating results by technology:

Phase I	Wind	Gas	Coal	Hydro	Market PPA	Total
High	4	5	0	0	4	13
Medium	4	3	0	3	13	23
Low	5	8	1	1	42	57
Total	13	16	1	4	59	93

Please see Exhibit No. ___(RG-3HC) at pages 164–75 for the Phase I results and quantitative rankings of proposals.

C. <u>Selection of Phase I Candidate Short List</u>

Q. How did PSE choose resources for the Phase I Candidate Short List?

A. PSE selected those with the highest qualitative and quantitative rankings by technology for the Phase I Candidate Short List. Proposals selected for the Phase I Candidate Short List were economically attractive based on their portfolio benefit ratio, their permitting and development feasibility, their commercial viability, and their potential for financing. Please see Exhibit No. ___(RG-3HC) at page 207 for the Phase I Candidate Short List.

Q. Did PSE select at least one proposal from each resource type for the Phase I Candidate Short List?

A. No. Unlike previous RFP processes, PSE did not select at least one proposal from each resource type for the Phase I Candidate Short List. PSE elected not to select the coal proposal for the Phase I Candidate Short List because PSE projected high costs and environmental risks. Likewise, PSE did not select hydro proposals for the Phase I Candidate Short List because PSE projected that the hydro proposals faced unresolved transmission challenges or did not reduce market price risk.

Q. What characteristics prevented proposals from being selected for the Phase I Candidate Short List?

A. Proposals not selected for the Phase I Candidate Short List generally exhibited one or more of the following characteristics: (i) immature development; (ii) less competitive economics; (iii) uncertainty around proposal feasibility and schedule; (iv) no transmission solution or greater uncertainty of obtaining transmission (e.g., low queue position); and (v) technology risk. Additionally, one respondent withdrew its proposal toward the end of Phase I. Please see Exhibit No. ___(RG-3HC) at page 209 for a list of proposals not selected for the Phase I Candidate Short List and the key factor(s) influencing each decision.

Q. What other factors influenced the selection of proposals for the Phase I Candidate Short List?

A. During Phase I of the 2008 RFP, Standard and Poor's ("S&P") updated its imputed debt calculation methodology. One significant change was that S&P added an implied depreciation expense to funds from operations (FFO) ratios. This update reduced the impact of PPAs on PSE's credit rating. PSE therefore increased the number of PPA proposals recommended for the Phase I Candidate Short List. By including more PPA proposals on the Phase I Candidate Short List, PSE could determine whether any PPA might evaluate better in PSE's Phase II PSM, which PSE modified to reflect the modified S&P methodology.

D. Overview of Phase II Quantitative Analysis

1. Phase II: Evaluation of RFP Proposals on the Phase I Candidate Short List

Q. What is the purpose of PSE's quantitative evaluation process in Phase I and Phase II of the 2008 RFP?

A. PSE's quantitative evaluation process in Phase I of the 2008 RFP screens out the highest cost and infeasible proposals. In doing so, PSE's quantitative team works closely with the other PSE working groups to evaluate the costs of the proposals. The Phase II quantitative analysis performs a more comprehensive review of the proposals on the Phase I Candidate Short List to evaluate their respective costs and risks.

Q. How did PSE evaluate costs of proposals on the Phase I Candidate Short List?

A. In Phase II, PSE obtained additional information from bidders. PSE requested additional cost data and wind data to evaluate costs of proposals on the Phase I Candidate Short List. Using this additional information, in part, the quantitative team refined inputs into the PSM to evaluate proposals against one another for Phase II.

Q. Did PSE use generic fixed and variable operations and maintenance costs to compare natural gas plant proposals in Phase II?

A. Yes. For natural gas plant ownership proposals in the 2008 RFP, PSE found it difficult to verify operations and maintenance costs based on the information provided in the RFP process because potential counterparties only shared high level information about operating and maintenance costs. PSE used the 2008 RFP generic fixed and variable operations and maintenance costs for screening. PSE first developed these generic costs for the 2007 IRP based on PSE's operations experience with its Fredrickson and Goldendale combined cycle combustion turbine plants.

Q. How did PSE evaluate risks of proposals on the Phase I Candidate Short List?

A. To evaluate risk of price volatility and energy policy uncertainty, PSE examined each proposal in five different future price environments (static results) and performed Monte Carlo Analysis on the Current Trends scenario (dynamic results). For static results, PSE used scenarios to examine risks associated with various expected natural gas prices, power prices, load growth, emissions costs, and capital cost escalation rates. For dynamic results, PSE used Monte Carlo analysis to examine 100 different combinations of annual changes in natural gas prices, electric power prices, hydro generation, and wind generation for new resources. Additionally, the quantitative team examined portfolios of resources to evaluate timing differences of potential acquisition opportunities.

PSE examined each of the above-described metrics separately and interpreted the overall value of a resource or group of resources in the selection of the Phase II Final Short List. Please see Exhibit No. ___(RG-3HC) at pages 22–25 for more information regarding PSE's Phase II quantitative evaluation process.

Q. Did PSE update its models for Phase II of the 2008 RFP?

A. Yes. PSE updated three price scenarios (Current Trends, Green World, and Low Growth) in AURORA with current forward market gas prices through 2012. Please see Exhibit No. ___(WJE-5) for an AURORA price scenario comparison matrix.

Additionally, PSE updated projected wind and combined cycle generic capital costs. PSE updated the wind generic capital costs based on wind ownership proposals received before and during Phase I of the 2008 RFP. PSE performed a market survey of other utilities, consultants, and EPC contractors to project capital costs for a new combined cycle plant because PSE did not receive bids to construct a new combined cycle combustion turbine. Please see Exhibit No. ___(WJE-6) for the Phase I and updated Phase II projected wind and combined cycle generic capital costs.

As discussed above, PSE also updated the PSM to include a change in the imputed debt calculation for PPAs in selection of the Phase I Candidate Short List

Finally, PSE updated the costs associated with the wind integration tariff of Bonneville Power Administration.

Q. Please summarize the evaluation of the proposals in the five different future price scenarios used in the Phase II Evaluation.

A. The five PSM static scenarios are as follows:

1. Current Trends, which consists of moderate gas prices, moderate carbon costs, and moderate load growth;

2. Green World, which consists of high gas prices, high carbon costs, and low load growth;

3. Low Growth, which consists of low gas prices, moderate carbon costs, and low load growth;

4. Lower Technology Cost, which consists of Current Trends with low generic wind and gas-fired combined cycle combustion turbine ("CCCT") capital costs; and

5. Higher Technology Cost, which consists of Current Trends with high generic wind and CCCT capital costs.

Please see Exhibit No. ___(WJE-7HC) for a chart that illustrates the benefit ratio versus portfolio benefit for each of the proposals on the Phase I Candidate Short List.

Q. Please explain the portfolio benefit and portfolio benefit ratio axes that are shown on the scatter-plot graph presented in Exhibit No. ___(WJE-7HC).

A. The portfolio benefit axis represents the 20-year present value of all portfolio benefits derived from each proposal in comparison to the 2007 IRP generic portfolio. The portfolio benefit ratio axis represents the present value of portfolio benefit divided by the present value of revenue requirements. In general, PSE prefers proposals that both provide significant portfolio benefits and are cost effective in delivery of those benefits as indicated by a high portfolio benefit ratio.

Q. What conclusions can PSE draw from the scatter-plot graph presented in Exhibit No. ___(WJE-7HC)?

A. Based upon the metrics of portfolio benefit and portfolio benefit ratio for all price scenarios, PSE can draw the following conclusions regarding the proposals on the Phase I Candidate Short List:

1. wind resource proposals tended to have the highest benefit ratios and portfolio benefits;
2. natural gas proposals tended to have a higher portfolio benefit than system PPAs;
3. natural gas proposals and system PPA proposals tended to

have wide ranges of portfolio benefit ratios; and

4. most proposals on the Phase I Candidate Short List (except two) would likely provide portfolio benefits in all scenarios as compared to the generic portfolio.

Q. How did the proposals on the Phase I Candidate Short List compare on the basis of levelized cost?

A. Generally, system PPAs and wind proposals tended to have the lowest levelized cost, and natural gas proposals tended to have the highest levelized costs. System PPA costs were typically low because of the shorter term of the proposal and the immediacy of the service. Levelized cost of natural gas plants are higher because they are typically running when the variable cost of fuel displaces an even higher cost of market purchases. In the Green World scenario levelized costs were significantly higher for natural gas plants because of the higher carbon costs associated with their emissions of carbon dioxide. Please see Exhibit No. ___(WJE-8HC) for a chart that compares proposals on the Phase I Candidate Short List resources based on levelized cost.

Q. Please summarize the evaluation of the proposals using Monte Carlo analysis in the Phase II evaluation.

A. As another measure of risk, PSE performed Monte Carlo analysis in the Current Trends scenario in which power prices, gas prices, wind conditions and hydro conditions were varied over one hundred trials. For each trial, a total portfolio cost measure is determined. PSE examined the average of the ten worst total portfolio cost from these trials. PSE viewed proposals with a lower average of the ten worst trials for portfolio cost as the most favorable. All proposals evaluated produced a lower ten worst trial cost and lower median portfolio cost than the 2007 IRP generic resource portfolio. Please see Exhibit No. ___(WJE-9HC) for the dynamic results for each proposal on the Phase I Candidate Short List.

2. <u>Evaluation of Portfolios Comprised of the Proposals on the Phase I Candidate Short List</u>

Q. Did PSE evaluate portfolios of the proposals on the Phase I Candidate Short List?

A. Yes. PSE combined proposals on the Phase I Candidate Short List to create eight portfolios to evaluate. PSE then compared combinations of proposals on the Phase I Candidate Short List to the generic strategy in the 2007 IRP.

Q. What was the purpose of the portfolio analysis?

A. The Phase II portfolio analysis evaluated (i) the timing of different combinations of proposals; (ii) how the different combinations of proposals evaluate in the different price scenarios; and (iii) whether large or small resources fit better within the portfolio. The ability to test each of these three factors is dependent upon the resources available to PSE.

Q. How did PSE combine proposals on the Phase I Candidate Short List into portfolios?

A. PSE designed portfolios to examine timing of adding natural gas resources and system PPAs to the portfolio. Timing is important because, with the addition of certain resources, PSE may be long in generation and capacity in the near term. The PSM results reflect a capacity benefit by displacing generic capacity only when there is a need for the capacity.

For each portfolio, PSE included the remaining wind PPAs because they evaluated very well individually and satisfy PSE's requirement to add low-cost renewable resources to meet the Energy Independence Act, Chapter 19.285 RCW.

PSE developed eight portfolios of proposals on the Phase I Candidate Short List. After the final selection of proposals for the Phase II Final Short List, PSE added a ninth portfolio that contained each such proposal to compare against the other portfolios examined in Phase II. Please see Exhibit No. ___(WJE-10HC) at page 1 for a list of (i) the eight portfolios of proposals on the Phase I Candidate Short List and (ii) the one portfolio that contained each proposal on the Phase II Final Short List.

Q. How did PSE evaluate the cost and risk of each portfolio of proposals on the Phase I Candidate Short List?

A. PSE evaluated the costs and risks of each portfolio of proposals on the Phase I

Candidate Short List in the same manner that PSE evaluated individual projects. Specifically, PSE (i) examined each portfolio in light of the five different future price scenarios (Current Trends, Green World, Low Growth, Lower Technology Cost, and Higher Technology Cost) and (ii) performed a Monte Carlo analysis of each portfolio in the Current Trends scenario.

Q. Did each portfolio of proposals on the Phase I Candidate Short List show a benefit as compared to the 2007 IRP resource strategy?

A. Yes. Each portfolio of proposals on the Phase I Candidate Short List showed a benefit as compared to the 2007 IRP resource strategy. Please see Exhibit No. ___(WJE-10HC) at pages 2–3 for the results of the Current Trends Static and Dynamic Analysis for each of the eight original portfolio combinations.

3. <u>Final Quantitative Ranking of Proposals Considered in Phase II</u>

Q. Please summarize the quantitative team's final ranking of the Phase II proposals.

A. To provide a final quantitative ranking of the individual proposals in Phase II of the 2007 RFP, PSE measured the results of such proposals based on the results of Levelized Cost ($/MWh), Benefit Ratio, Portfolio Benefit ($MM), Scenario Dispersion, and Dynamic Analysis average of the ten highest cost trials ($MM).

For each ranking, the quantitative team assigned an ordinal value associated with best, better and good (Best = 1, Better = 2, and Good = 3). The following table illustrates the breakdown of values for each metric:

Rank / Ordinal Score	Best	Better	Good
	1	2	3
Levelized Cost ($/MWh)	<=125	>125 and <= 165	>165
Benefit Ratio	>0.25	>0.1 and <=0.25	<0.1
Portfolio Benefit ($MM)	>100	>50 and <=100	<=50
Scenario Dispersion	Tight		Wide
Dynamic Analysis ($MM)	<16,275		>=16,275

Additionally, PSE assigned a final quantitative score to each proposal evaluated in Phase II based on the average of Levelized Cost ($/MWh), Benefit Ratio, Portfolio Benefit ($MM), Scenario Dispersion, and Dynamic Analysis ($MM).

Q. What were the final rankings of the proposals evaluated in Phase II?

A. Final scores of the proposals evaluated in Phase II ranged from a 1.0 to 2.6. After scoring each proposal based on results of the metrics, the quantitative team assigned an overall high, medium, and low rating based on the quantitative score and the other cost implications that the model is not able to capture. Examples of these costs are tolling constraints with minimum capacity factors and gas pricing at a trading hub not typically used by PSE's power operations group.

From a quantitative perspective, each proposal evaluated in Phase II compared favorably to the 2007 IRP generic resources. The final cost for each proposal will ultimately be reached through negotiations.

The following table summarizes the Phase II rating results by technology:

Phase II	Wind	Gas	Market PPA	Total
High	2	1	0	3
Medium	0	3	2	6
Low	0	2	2	3
Total	2	6	4	1

Please see Exhibit No. ___(WJE-11HC) at page 21 for the Phase II results and quantitative rankings of proposals on the Phase I Candidate Short List.

E. <u>Selection of Phase II Final Short List</u>

Q. Please describe how the RFP team selected the Phase II Final Short List.

A. PSE held an all-team working group meeting on July 9, 2008 to review the qualitative and quantitative rankings and to select a Phase II Final Short List. PSE's selection process resulted in three possible designations: (i) selected to Phase II Candidate Short List, (ii) selected to the continuing investigation list, or (iii) not selected.

Q. What types of proposals did PSE select for the Phase II Final Short List?

A. For the Phase II Final Short List, PSE selected two wind PPAs, one natural gas ownership offer, and one short-term system PPA structure. Overall, the proposals selected for the Phase II Final Short List provided the greatest benefit to PSE's portfolio with the lowest reasonable cost and risk. More specifically, these proposals exhibited the following benefits at conclusion of Phase II of the RFP in July 2008:

1. [redacted] Wind PPA – The [redacted] Wind PPA featured a 20-year term with an attractive price, good capacity factor, and a strong counterparty. Project feasibility was high, with permitting expected in 2008. The [redacted] project was located in an area that offers PSE diversity in its wind resource portfolio and has a high queue position to obtain transmission.

2. [redacted] Wind PPA – The [redacted] Wind PPA featured a 20-year term with a prepay structure that models well for PSE. This [redacted] project has a good transmission situation and is in an advanced stage of development. The project also benefits from a favorable capacity factor and a strong counterparty.

3. Mint Farm Generation Station Ownership – The Mint Farm Energy Center featured an offer to purchase an existing combined cycle plant at an attractive capital cost for a completed, low heat rate plant. The Mint Farm Energy Center provides synergy with PSE's existing Goldendale plant and was one of only two remaining CCCT plants in the Pacific Northwest at the close of the evaluation process. This plant also provides needed baseload generation to support PSE's growing need and has firm point-to-point transmission to PSE's system.

4. Barclays System PPA – Finally, PSE selected a four-year, fixed price system PPA structure offered by Barclays, that features around-the-clock, winter delivery to the Mid-C. This product offers a firm purchase of power that complements PSE's winter need shape. The selected counterparty is strong and the economics at the proposed price are attractive. Due to the limited lifespan of short-term PPA prices, PSE issued a "mini-RFP" at the close of the All Source RFP to refresh the pricing of this product with several qualified counterparties.

Please see Exhibit No. ___(WJE-11HC) for presentation of the final quantitative selection matrix.

F. Proposals Selected for the Continuing Investigation List

Q. Please describe the proposals selected for the continuing investigation list.

A. PSE selected three proposals for the continuing investigation list. Please see Exhibit No. ___(RG-3HC) at pages 215–16 for the continuing investigation list.

III. DESCRIPTION OF ANALYSES OUTSIDE OF THE 2008 RFP PROCESS

Q. Please explain the model updates or analysis made outside of the 2008 RFP process.

A. At the conclusion of the 2007 IRP, PSE updated the models to continue to evaluate resource offers presented to PSE between RFP cycles. PSE refined the PSM as follows:

(i) revisions to the calculation of renewable energy necessary to meet the Washington State renewable portfolio standard,

(ii) improved output formatting,

(iii) improved calculation of end effects,

(iv) inclusion of renewable energy credit ("REC") value for renewable acquisitions in the levelized cost of the resource,

(v) adjusted load and resource need for conservation, and changes in resources.

Q. Are resource proposals offered outside of an RFP evaluated to the same standard as resource proposals offered as part of an RFP?

A. Yes. PSE evaluated resource proposals offered outside of an RFP to the same standard as resource proposals offered as part of an RFP. Outside of the RFP process, PSE may not have as many reasonably available alternatives for comparison, but PSE uses similar modeling approaches and decision variables.

Q. What types of resources did PSE evaluate between the 2007 IRP and 2008 RFP?

A. PSE received offers for wind ownership, wind PPAs, small hydro PPAs, and other small renewable projects.

Q. Did the evaluation of resources lead to the selection of any resources?

A. Yes. Prior to the 2008 RFP, PSE entered into the Nooksack Hydro 5-Year PPA and acquired the development rights to the Wild Horse expansion project. Please see the discussion of each of these resources below.

Q. What types of resources did PSE evaluate after the 2008 RFP?

A. PSE continued to negotiate and evaluate updates to the wind proposals selected in the RFP. Additionally, PSE evaluated market PPAs, natural gas turbines, and other small renewable projects.

Q. Did the evaluation of resources lead to the selection of any resources?

A. PSE entered into a five-year PPA with Qualco Energy Dairy Digester and a four year three-month PPA with Credit Suisse. Additionally, PSE decided to construct the Wild Horse expansion project and to purchase the Fredonia Gas Turbine Units

No. 3 and No. 4.

IV. QUANTITATIVE EVALUATION OF RESOURCES

A. Quantitative Analysis of Proposals Acquired Pursuant to the 2008 RFP Process

1. Mint Farm Energy Center

Q. Does the quantitative analysis support the acquisition of the Mint Farm Energy Center?

A. Yes. PSE has a demonstrated need for both gas and wind plants according to the resource strategy and need defined in PSE's 2007 IRP and as updated for the 2008 RFP. The quantitative analyses conducted during the Phase II of the 2008 RFP process projected that the Mint Farm Energy Center was a reasonable cost, base load resource that was immediately available. Please see Exhibit No. ___(WJE-11HC) for the overall evaluation results of the Phase II, including the specific quantitative evaluation results of the Mint Farm Energy Center and other RFP candidate short list proposals.

Q. Please describe the quantitative analysis results of the Mint Farm Energy Center in Phase II of the RFP evaluation.

A. The projected net present value portfolio benefit of the Mint Farm Energy Center was $45 million when compared to generic resources, with a levelized cost of $[redacted]/MWh in the PSM model, and a benefit ratio of 0.05. Please see Exhibit

No. ___(WJE-11HC).

Compared to the other Phase II Final Short List proposals the quantitative team gave Mint Farm a medium rating because of its positive benefit ratio as compared to generics. However, Mint Farm is an attractive natural gas resource based on its levelized cost, capital cost and operational flexibility. The acquisition of the Mint Farm Energy Center is consistent with the wind generation and gas generation strategy identified in the 2007 IRP.

Over a 20-year analysis period, the Mint Farm Energy Center provides approximately $45 million of portfolio benefit relative to the 2007 IRP's least cost generic portfolio. The Mint Farm Energy Center helps PSE meet the significant resource shortfall identified in the 2007 IRP and is an efficient gas plant that is currently permitted and operating.

With an "all in" capital investment cost of approximately $860/kW, the Mint Farm Energy Center is an opportunistic and lower risk alternative to construction of a new plant.

Q. Please describe the quantitative analysis of the Mint Farm Energy Center as presented to the Board of Directors?

A. In addition to the evaluation of the Mint Farm Energy Center in the PSM and comparing to the resources offered in response the 2008 RFP, PSE also presented a detailed project pro forma to the Board of Directors. This pro forma showed an overall levelized cost of $[redacted]/MWh. *See* Exhibit No. ___(RG–HC7) at pages 74 to 99 for the pro forma exhibit.

Q. Have the costs presented to the Board of Directors been refined?

A. Yes. As described in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), the due diligence performed by PSE on the Mint Farm Energy Center identified capital plant improvements that would be required to operate the plant within PSE's standards. Please see Exhibit No. ___(RG-12) for a description of the operating standards.

Q. What are the projected costs of the improvements necessary to operate the Mint Farm Energy Center within PSE's standards?

A. The projected costs of the improvements necessary to operate the Mint Farm Energy Center within PSE's standards were approximately $10.5 million. As of May 2009, PSE still projects these costs to be approximately $10.5 million.

Q. Do these projected improvement costs associated with the Mint Farm Energy Center affect the projected portfolio benefit for the Mint Farm Energy Center?

A. Yes. The addition of $10.5 million of improvement costs would reduce the net present value portfolio benefit of $45 million, on a dollar-for-dollar basis, to approximately $34.5 million.

Q. What were the assumptions of the Mint Farm Energy Center operation in the quantitative modeling?

A. Based on engineering input, the quantitative evaluation team assumed 259.8 MW of base load and 36.6 MW of duct firing. With an assumed forced outage rate of 5% and annual maintenance of approximately 2 weeks, the plant has an expected modeled availability of over 90%. The forecast generation and resulting capacity factor depends upon model logic as well as the anticipated economic relationship between the market price of gas, market price of power and the efficiency of the plant. The annual capacity factor, including both primary firing and duct firing, ranged from 27% to 49%. *See* Exhibit No. ___(RG-7HC) at pages 82–83.

The following table contains model estimates of operating capacity factors:

	20-yr Capacity Factor 260 MW (296 MW)
RFP Phase II- PSM 11-3 Current Trends	28% (25%)
Board Book Pro forma- AURORA	37% (31%)
General Rate Case 2009 Pro forma- AURORA	46% (40%)

PSE performed an additional evaluation of the range of capacity factors by looking at the annual capacity factors for the Mint Farm Energy Center, as forecast by the current 2009 Integrated Resource Plan. The results of that evaluation show that Mint Farm, primary firing, ran at a capacity factor of over 60% (i) in 824 years out of the 1,800 years of the total Monte Carlo tested years for the Current Trends price scenario and (ii) in 333 years out of the 1,800 years of the total Monte Carlo tested years in the Business as Usual price scenario. Please see Exhibit No. ___(WJE-12) for the results of the evaluation of the range of capacity factors for the Mint Farm Energy Center.

Q. **How does the purchase of the Mint Farm Energy Center compare to the construction of a new gas plant?**

A. PSE purchased the Mint Farm Energy Center for an "all in" cost of about $254 million (approximately $860 per kW, based on the primary and duct firing, 296 MW of output). *See* Exhibit No. ___(RG-1HCT). PSE projects that this price is less than the estimated cost of a new combined cycle combustion cycle turbine (approximately $1,330/KW, based on a survey of capital costs conducted in April 2008). Please see Exhibit No. ___(WJE-13HC) for the results of PSE's survey of capital costs conducted in April 2008. The engineering team independently surveyed the Shaw Group and General Electric to determine the $415 million replacement value that is being used for insuring the plant.

Q. **Have the Mint Farm costs been updated since the Board of Directors analysis?**

A. Yes, the quantitative team continued to update and revise the pro forma. The current estimated levelized cost of the Mint Farm Energy Center is $[redacted]/MWh. Please see Exhibit No. ___(RG-13C) for an updated project pro forma financial statements for the Mint Farm Energy Center.

2. Barclays Four-year Winter PPA

Q. Please explain the structure of the Barclays Four-year Winter PPA proposal.

A. The Barclays Four-year Winter PPA proposal was a Four-year PPA for deliveries during the November through March periods (the "Proposed Structure"). The Proposed Structure also called for capacity that varied from 50 MW to 175 MW, depending on the month of delivery. The PPA under the Proposed Structure would have commenced on November 1, 2011, and expired on March 31, 2015.

Q. Please explain quantitative analysis performed by PSE for the Barclays Four-year Winter PPA.

A. PSE analyzed the Barclays Four-year Winter PPA in Phase 1 and Phase 2 of the RFP process. In each of Phase I and Phase II, the Barclays Four-year Winter PPA projected to be the most attractive market PPA for PSE. The following table presents the key Phase I and Phase II quantitative results for the Proposed Structure of the Barclays Four-year Winter PPA:

	Phase I	Phase II
Levelized Cost	$[redacted]/MWh	$[redacted]/MWh
Portfolio Benefit	$22.413 million	$39.973 million
Benefit Ratio	0.1609	0.3014

Q. Did the Barclays Four-year Winter PPA final structure change from the Proposed Structure?

A. Yes. The final structure of the Barclays Four-year Winter PPA consists of a four-year, 75 MW PPA with deliveries around the clock seven days a week during November through February (the "Final Structure"). The PPA under the Final Structure commences on November 1, 2011, and expires on February 28, 2015.

Q. Why did the Barclays Four-year Winter PPA change from the Proposed Structure to the Final Structure?

A. Two key differences exist between the Proposed Structure and the Final Structure: period of delivery and capacity. During Phase II evaluation, PSE determined that deliveries during March are less valuable. In addition, PSE's Power Operations indicated that hedging often used a quarterly term, January through March, and PSE might end up with more March power than needed. As a result, a structure limited to deliveries during a November through February time would match PSE's needs more closely.

Additionally, PSE determined during Phase II of the 2008 RFP process that the capacity of the Proposed Structure, which ranged from 50 to 175 MW depending on month, presented too much concentration risk with a single counterparty, particularly given the extremely volatile capital markets. PSE decided that a flat 75 MW capacity would reduce PSE's exposure to any one entity but simultaneously offer a large enough product to encourage bidding interest.

Q. How did PSE determine that the Final Structure would be more optimal than the Proposed Structure?

A. PSE asked Barclays to produce an indicative price for a Four-year Winter PPA based on a structure similar to the Final Structure. PSE evaluated this price with PSM and found that such structure evaluated slightly better than the Proposed Structure. The Final Structure projected to have a more attractive levelized cost and benefit ratio. It should be noted, however, that the Proposed Structure had a larger portfolio benefit because of its larger average capacity. The following table presents the price and PSM quantitative measures of the Final Structure.

	Final Structure
Price	$[redacted]/MWh
Levelized Cost	$[redacted]/MWh
Portfolio Benefit	$26.9 million
Benefit Ratio	0.57

Q. How did the counterparties secure final pricing for the Barclays Four-year Winter Only PPA.

A. To confirm that PSE could secure a competitive price for the Barclays Four-year Winter Only PPA, PSE held a live pricing solicitation on October 9, 2009 for prequalified counterparties and received active prices from three counterparties including Barclays. PSE analyzed each of the three bids with PSM. Again, the Barclays Four-year Winter Only PPA projected to have the lowest and most attractive price.

B. Quantitative Analysis of Proposals Acquired Outside of the 2008 RFP Process

1. Wild Horse Wind Project Expansion

Q. Was the Wild Horse Wind Project Expansion proposed in response to the 2008 RFP Process?

A. No. Whiskey Ridge Power Partners, LLC first proposed the Wild Horse Wind Project Expansion to PSE in June 2007. (At that time, the Wild Horse Wind Project was known as the Whiskey Ridge Wind Project.)

Q. Please describe the quantitative analysis process for selecting the Wild Horse Wind Project Expansion?

A. For the Wild Horse Wind Project Expansion, PSE evaluated the project in two steps. The first step was to determine whether PSE should purchase the development rights. The second step was to determine whether PSE should move forward with the construction of the project and enter into a turbine supply agreement.

Q. Did PSE apply the PSM for the purchase of development rights for the Wild Horse Wind Project Expansion?

A. Yes. In addition to using the PSM to compare the Wild Horse Wind Project

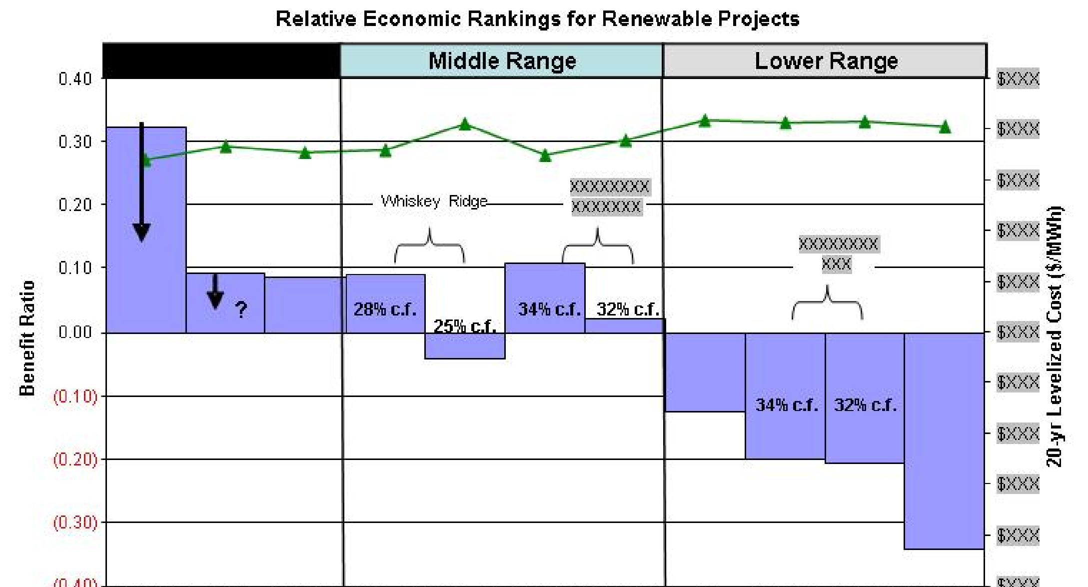
Expansion costs with other alternatives available at the time, PSE applied the PSM for the purchase of development rights for the Wild Horse Wind Project Expansion. PSE also evaluated the reasonableness of the cost for just the development rights, as discussed in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT).

Q. Please describe the analytic and screening results for the purchase of the development rights for the Wild Horse Wind Project Expansion.

A. The results of the analysis using the PSM to acquire the development rights for the Wild Horse Wind Project Expansion demonstrated that such project expansion was in the middle range of relative economic rankings of renewable projects that had been offered prior to the 2008 RFP. As shown in the table below, renewable projects were categorized in three ranges (high, middle and low):

Comparative Analysis from January 2008 for Acquisition of Development Rights

Relative Economic Rankings for Renewable Projects



	XXXXXXX XXXXXXXX XXXXXXX	XXXXX XXXXX XXXXXX	XXXXXXX XXX XXXXXXX	Whiskey Rdg Wind Ownership	Whiskey Rdg Wind Ownership	XXXXXXXX XXX XXXXXXX	XXXXXXXX XXX XXXXXXX	XX XXX XXXXXX	XXXXXXX XXX XXXXXX	XXXXXXXX XXX XXXXXX	XXXXXXXX XXX XXXXXXX
Benefit Ratio	0.32	0.09	0.09	0.09	(0.04)	0.11	0.02	(0.13)	(0.20)	(0.21)	(0.34)
Levelized Cost	$XXX	$XXX	$XXX	$XXX	$XXX	$XXX	$XXX	$XXX	$XXX	$XXX	$XXX
Portfolio Benefit ($MM)	$29	$24	$9	$7	($3)	$38	$8	($34)	($78)	($76)	($44)

The high range consisted of those projects that, at the time of the analysis, were clearly positive as measured by their portfolio benefits and their benefit ratios. The middle range included proposals that were sensitive to various economic attributes, such as capital cost or capacity factor. Projects identified in this range were either break even or slightly better than break even when compared to generic resource costs. Finally, projects in the low range were those that produced a negative portfolio benefit and benefit ratio. Please see Exhibit No. ___(WJE-14HC) for a table of project risks and benefits, which shows the benefit/cost rate, commercial status, and the projects pros and cons.

Ultimately, PSE was not able to execute on the three projects that evaluated in the high range—[redacted] Biomass, [redacted], and [redacted] Wind—due to increased pricing, inability to confirm the geothermal resource and permitting challenges, respectively. Similarly, the projects in the low range disappeared as the permitting process for [redacted] was delayed, [redacted] development seems to be stalled and the proposal to sign a PPA for the [redacted] project was rescinded. These events highlight the fast moving changes present in the Pacific Northwest wind market during 2007 and the first half of 2008.

Q. Please describe the analytic process for the decision to construct the Wild Horse Wind Project Expansion.

A. For the decision to construct the Wild Horse Wind Project Expansion, PSE conducted PSM analyses to compare project economics with other projects that PSE was considering at the time as shown in the table above.

PSE also compared the project results to the projects on the Phase I Candidate Short List. Please see Exhibit No. ___(RG-39HC) at page 136 (Figure E5-2) for a table of the comparative analysis results for the Wild Horse Wind Project Expansion from October 2008. At the time of the Wild Horse expansion project decision, the costs for the RFP short-list wind projects were increasing and the terms were becoming less favorable. At that same time there was also concern about whether or not these projects could be executed in the near term.

PSE designed an MS Excel-based project pro forma model that contained a detailed budget for construction, operations, and maintenance of the Wild Horse Wind Project Expansion. The pro forma provides a greater level of detail used for analyzing the impacts of the potential expiration of the federal production tax credit ("PTC") and of the Washington State Sales Tax Exemption for Renewable Generating Assets in negotiating the definitive agreements for the Wild Horse Wind Project Expansion.

Q. Please describe the analytic results for the decision to construct the Wild Horse Wind Project Expansion.

A. PSE's analytic results projected a $[redacted]/MWh levelized cost for the Wild Horse Wind Project Expansion in the pro forma, with three million dollars of portfolio benefit as compared to the 2007 IRP Generic portfolio from the PSM.

Q. Please describe the risks PSE considered when evaluating the Wild Horse Wind Project Expansion.

A. The key risks considered when determining whether to move forward with Wild Horse Wind Project Expansion in 2009 or delaying until 2010 were the possible extension of the federal PTC, the extension of the Washington State Sales Tax Exemption for Renewable Generating Assets, and the possibility of an appeal of the permit application.

In October 2008, the PTC for wind projects was only available to wind projects placed in service on or before December 31, 2009. At that time, it was unknown whether the PTC would be extended beyond December 31, 2009. (The PSM analysis assumed that PTCs would have been available for 2010 projects.) Moving forward with the Wild Horse Wind Project Expansion as a 2009 project would allow PSE to capture a minimum of $21/MWh of PTC and thereby minimize project cost. If PSE had delayed the Wild Horse Wind Project Expansion until 2010 and the PTC not been extended to 2010, PSE would have failed to capture additional portfolio benefit.

The second financial risk PSE considered when making the determination to proceed with Wild Horse Wind Project Expansion in 2009 was the Washington State Sales Tax Exemption on Renewable Generating Assets. This rule stipulates that renewable generating assets, such as wind turbine generators ("WTGs"), are exempt from state sales tax if acquired by June 30, 2009. Moving forward with the development of the Wild Horse Wind Project Expansion in 2009 allowed PSE to avoid this expenditure because PSE will purchase WTGs for the Wild Horse Wind Project Expansion prior to the end of June 2009. The cost to PSE to acquire the WTGs is $[redacted] million. By proceeding with the Wild Horse Wind Project Expansion in 2009 and purchasing equipment prior to the expiration of this sales tax exemption, PSE saved a minimum of $[redacted] million (eight percent of $[redacted] million).

Q. Has PSE updated the project economics since receiving approval from the Board of Directors for the Wild Horse Wind Project Expansion in November 2008?

A. Yes. PSE updates the project pro forma on an ongoing basis as costs, such as the balance of plant are refined, and as actual expenditures are recorded in PSE's accounting records. As described in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), PSE projects that the "all-in" project cost of the Wild Horse Wind Project Expansion will be $5 million less than the budget submitted to the Board of Directors in November 2008. These new projections result in a $[redacted]/MWh levelized cost for the Wild Horse Wind Project Expansion.

Q. Do you anticipate any future changes to the economics of the Wild Horse Wind Project Expansion?

A. Yes. PSE is investigating additional possible positive impacts of the American Recovery and Reinvestment Act of 2009 (the "Stimulus Bill"), which was enacted in February 2009. The Stimulus Bill extends the deadline to place wind farms in service through 2012 to qualify for PTCs. The Stimulus Bill also gives wind developers the option to forego PTCs and claim a 30% investment tax credit instead for projects completed during 2009 and 2010, or through 2012 for projects that have commenced construction prior to the end of 2010. Alternatively, PSE will have the option to forego tax credits and receive a check from the U.S. Treasury for 30% of the qualifying costs.

2. Nooksack Hydro Five-year PPA

Q. Was the Nooksack Hydroelectric Five-year PPA proposed as part of the 2008 RFP?

A. No, approximately a year prior to the expiration of the then current PPA, Puget Sound Hydro approached PSE to determine PSE's interest in renewing the PPA.

Q. Please describe the analysis of the Nooksack PPA?

A. PSE conducted two analyses in determining that the five-year PPA with Puget Sound Hydro evaluated favorably.

The first was a PSM version 10-2 analysis, which projected favorable results due to the Nooksack Project's high capacity factor, generation shape, and low cost purchase price per MWh. The portfolio benefit was $272,000, with a benefit ratio of about 0.07. Please see Exhibit No. ___(WJE-15C) for the results of the PSM version 10-2 quantitative analysis for the Nooksack Hydro Five-year PPA.

PSE conducted a second analysis to confirm project economics relative to the forward marks at the time PSE and Puget Sound Hydro were conducting PPA negotiations. This analysis projected that a flat $[redacted]/MWh contract price was more favorable than a price indexed to the Dow Jones Mid-Columbia Electricity Price Index by about $500,000:

Nooksack Forward Prices 1/9/08

Forward Marks 01/09/08	**5-year NPV**
Nooksack	$3,897,101
Mid-C Flat	$4,393,330
Difference (Savings)/ Cost	($496,200)

Note: Does not include transmission or imputed debt cost

3. Qualco Energy Dairy Digester Five-year PPA

Q. What financial analysis did PSE undertake to determine that the five-year PPA with Qualco Energy evaluated favorably?

A. PSE evaluates proposals greater than 1 MW in capacity with the PSM. Because the capacity of the Qualco Energy dairy digester is less than 1 MW, PSE compared the Schedule 91 prices (plus the wheeling and administrative fees paid by PSE to Snohomish PUD pursuant to the Aggregation and Delivery Agreement discussed below) to Qualco Energy with projected market prices. This analysis projected that the Qualco Energy Dairy Digester 5-year PPA provided benefits of approximately $80,000 over the five-year term of the PPA:

Qualco Dairy Digester
3/20/2008

Qualco NPV v Market Comparison	**NPV**
Qualco PPA NPV	$1,213,500
Forward Marks Power Purchase	$1,293,700
Difference (Savings) / Cost	($80,200)

4. <u>Credit Suisse Four-year Market PPA</u>

Q. Please describe the structure of the Credit Suisse Four-year Market PPA.

A. The Credit Suisse Four-year Market PPA is a four-year, three-month 50 MW PPA pursuant to Schedule C of the Western System Power Pool Agreement. Pursuant to the terms of the PPA, Credit Suisse will provide power around the clock, seven days a week. Please see Exhibit No. ___(RG-25C) for a copy of the Confirmation Agreement under the WSPP Agreement, dated as of September 16, 2008, between PSE and Credit Suisse.

Q. Please describe the analysis of the Credit Suisse Market PPA.

A. On September 16, 2008, PSE conducted a live pricing solicitation for the replacement of the Lehman Market PPA. PSE received bids from three prequalified bidders, each of which PSE analyzed in PSM. Credit Suisse's bid of $[redacted]/MWh was the winning bid, and was priced $1.05/MWh below the terminated PPA with Lehman. The following table displays the results of the price solicitation.

	Credit Suisse	Bidder 2	Bidder 3
Price	$[redacted]/MWh	$[redacted]/MWh	$[redacted]/MWh
Levelized Cost	$[redacted]/MWh	$[redacted]/MWh	$[redacted]/MWh
Portfolio Benefit	$5.057 million	$2.469 million	$3.209 million
Benefit Ratio	0.0511	0.0243	0.0318

5. <u>Fredonia Gas Turbine Units No. 3 and No. 4</u>

Q. Why did PSE evaluate the purchase of the Fredonia Gas Turbine Units No. 3 and No. 4?

A. As explained in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), PSE acquired two Pratt and Whitney FT8 combustion turbines, approximately 54 MW each with a heat rate of about [redacted] mmbtu/MWh, in 2001 and installed them at the Fredonia Generating Station property. In April 2001, PSE expanded the vehicle lease program with BLC Corporation to include the lease of Fredonia Gas Turbine Units No. 3 and No. 4. Please see Exhibit No. ___(RG-26C) for a copy of the lease. As also discussed in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), the lessor, GE Capital Commercial Inc. ("<u>GE Capital</u>"), terminated the lease with PSE, and PSE elected to exercise its rights under the lease to purchase Fredonia Gas Turbine Units No. 3 and No. 4.

Q. Did PSE have a need for the Fredonia Gas Turbine Units No. 3 and No. 4 in 2001?

A. Yes. In 2001, PSE leased the units to provide (i) ten-minute start capability for use as contingency reserves, (ii) energy reliability at a relatively low heat rate in a market affected by critically low hydro conditions and extremely volatile prices in 2001, and (iii) flexibility as peaking units.

Q. Does PSE have a continuing need for the Fredonia Gas Turbine Units No. 3 and No. 4?

A. Yes. PSE's ongoing need for capacity and energy is described in the 2007 IRP and was updated for the 2008 RFP. Please see Exhibit No. ___(WJE-3) for a table that depicts PSE's monthly energy and capacity need, projected as of January 7, 2008. Both calculations of need assumed the continuing services of the Fredonia No. 3 and No.4 units. At the meeting of the Energy Management Committee ("EMC") on November 19, 2008, the EMC members approved the 15 percent planning reserve margin as a new capacity standard for the 2009 Integrated Resource Plan (the "2009 IRP"). Please see Exhibit No. ___(WJE-16C) for minutes of the EMC meeting of November 19, 2008. Compared with the prior capacity standard, the 15% planning reserve margin had the effect of increasing the capacity need by approximately 300 MW.

At its meeting of January 14, 2009, the EMC reviewed draft charts for the 2009 IRP that projected that PSE will just meet the 15% planning reserve margin in 2010 and will experience a shortfall of over 1,318 MW in the year 2015, assuming that no new resources are acquired and that Fredonia Gas Turbine Units No. 3 and No 4 are in PSE's resource portfolio. Please see Exhibit No. ___(RG-29-HC) for a copy of a presentation to the EMC, dated January 14, 2009, regarding the acquisition of the Fredonia Gas Turbine Units No. 3 and No. 4. Without Fredonia Gas Turbine Units No. 3 and No. 4 in PSE's resource portfolio, the projected shortfall in 2015 would be larger by over 100 MW.

Q. What alternatives did PSE consider?

A. PSE considered the following three alternatives:

(i) Alternative 1 – Purchase the Fredonia Gas Turbine Units No. 3 and No. 4 for their unamortized value; and

(ii) Alternative 2 – Continue the lease, or re-lease, at an interest rate implied by current market conditions;

(iii) Alternative 3 – Replace Fredonia Gas Turbine Units No. 3 and No. 4 with a new gas-fired peaking resource.

Q. Were each of these three alternatives equally viable?

A. No. Based on discussions with GE Capital, PSE determined that Alternative 2 was not a valid alternative because GE Capital indicated it terminated the lease to improve GE Capital's liquidity and not because of dissatisfaction with the associated interest or rental rate.

Q. How did PSE quantitatively compare Alternative 1 with Alternative 3?

A. For Alternative 1 (purchase of Fredonia Gas Turbine Units No. 3 and No. 4 for their unamortized value), PSE considered the quantitative results based on a purchase price equal to the unamortized value of the units. For Alternative 3 (replacement of Fredonia Gas Turbine Units No. 3 and No. 4 with a new gas-fired peaking resource), PSE considered the quantitative results based on 2009 IRP assumptions for a new peaking resource.

Q. **What were the results of the quantitative analyses of Alternative 1 and Alternative 3?**

A. The quantitative analyses projected that the fixed costs of purchasing Fredonia Gas Turbine Units No. 3 and No. 4 for their unamortized value was less costly (projected revenue requirement of $47.5 million) than the fixed costs of replacing Fredonia Gas Turbine Units No. 3 and No. 4 with a new gas-fired peaking resource (projected revenue requirement of $129.4 million). Please see Exhibit No. ___(WJE-17C) for a comparison of the PSE alternatives to address the GE Capital's breach of lease with respect to Fredonia Gas Turbine Units No. 3 and No. 4.

Q. **Did PSE use the PSM to evaluate PSE's purchase of Fredonia Gas Turbine Units No. 3 and No. 4?**

A. Yes. PSE used the PSM to evaluate PSE's purchase of Fredonia Gas Turbine Units No. 3 and No. 4. The model results should be considered an approximation because the PSM 11-3 was used, and the capacity need in this version assumes that Fredonia Units No. 3 and No. 4 were available. This approximation underestimates the value of both alternatives. But since the underestimation applied to both alternatives, PSE used the PSM to provide only an indicative measure of the portfolio value associated with Fredonia Gas Turbine Units No. 3 and No. 4 as compared to a PSM run with a new peaking gas plant. The PSM model run projected that the purchase of Fredonia Gas Turbine Units No. 3

and No. 4 in 2010 was about half the cost of the purchase of a new peaking plant in the same year. This result is consistent with the fixed cost revenue requirement approach discussed above.

VI. REQUEST FOR A DETERMINATION THAT EACH OF THE MINT FARM ENERGY CENTER AND THE SUMAS COGENERATION STATION COMPLIES WITH THE GREENHOUSE GASES EMISSIONS PERFORMANCE STANDARDS IN RCW 80.80

A. <u>The Mint Farm Energy Center Complies With the Greenhouse Gases Emissions Performance Standards in RCW 80.80</u>

1. <u>PSE's 2007 IRP Process Identified a Need to Acquire Additional Electric Resources</u>

Q. Did PSE's 2007 IRP process identify a need to acquire additional electric resources?

A. Yes. PSE's 2007 IRP process identified a need to replace, renew and acquire nearly 700 aMW of electric resources by 2011, more than 1,600 aMW by 2015, and 2,570 aMW by 2025. The 2007 IRP *capacity* need was identified to be nearly 2,300 MW by 2015, and over 3,200 MW by 2020. Of the 2,300 MW of capacity need to be met by 2015, at least 1,234 MW of capacity additions were projected to be from gas-fired combined cycle electric generating plants. Please see Exhibit No. ___(KJH-5) for a copy of PSE's 2007 IRP.

Q. Did the 2007 IRP identify the type of electric generation resources that PSE will need to acquire to meet this need?

A. Yes. PSE' demand forecast and analysis of existing resources that was applied in PSE's 2007 IRP resulted in a forward-looking portfolio made up of the lowest reasonable cost long-term resources. The 2007 IRP recognized that the bulk of these resources will be CCCTs. In fact, the single largest type of new energy resource reflected in PSE's 2007 IRP is from gas-fired CCCT plants, such as the Mint Farm Energy Center

2. <u>The Mint Farm Energy Center Responds to the Needs Identified in PSE's 2007 IRP</u>

Q. Please describe the Mint Farm Energy Center and its development history.

A. Please see Section IV.A.1. above for a description of the Mint Farm Energy Center.

Q. How does the Mint Farm Energy Center respond to the needs identified in PSE's 2007 IRP?

A. The acquisition of the Mint Farm Energy Center is consistent with the strategy identified in PSE's 2007 IRP. The acquisition of the Mint Farm Energy Center provides PSE with a cost-effective and environmentally sound way to generate power that helps reduce PSE's resource deficit in the near term.

The combined cycle process at the Mint Farm Energy Center is an efficient process that provides greater operating efficiencies, lower fuel costs, and lower emissions. The operational flexibility of the plant provides PSE with the ability to dispatch the plant when it is determined to be the most efficient, low cost and reliable resource to meet system load or demand.

Q. Did PSE's evaluation of the proposals submitted through the 2008 RFP process demonstrate that the Mint Farm Energy Center is an appropriate resource to meet PSE's need for additional electric generation resources?

A. Yes. As discussed above, PSE's evaluation of the proposals submitted through the 2008 RFP process demonstrate that the Mint Farm Energy Center is an appropriate resource to meet PSE's need for additional electric generation resources. As also discussed above, the Mint Farm Energy Center represents an attractive price relative to new construction, and its low heat rate makes it one of the most efficient generating facilities in the WECC region. Additionally, the Mint Farm Energy Center has the potential to provide (i) ancillary services, such as load following, and (ii) transmission reliability due to its location on the west side of the state.

Q. Please explain what is meant by the term "transmission reliability."

A. As a west-side resource, the Mint Farm Energy Center provides not only needed energy but also transmission reliability. The project holds long-term firm transmission on the BPA line that delivers to PSE's load center at Covington.

PSE is in the process of moving the Mint Farm Energy Center out of BPA's balancing authority and into PSE's own balancing authority to allow for greater control of the resource and potential for load following and other ancillary services capabilities.

Early in the review process, it was apparent that the firm transmission capacity held by the Mint Farm Energy Center provided certainty and reduced risk to PSE and its customers. As the region has become more transmission constrained, projects without firm transmission capacity are likely to experience a reduced level of service. Many projects are not likely to receive firm transmission capacity until 2012/2013 at the earliest when BPA estimates completion of the McNary/John Day infrastructure project.

3. <u>The Mint Farm Energy Center is Designed to Run as a Baseload Facility, and PSE Intends to Operate It as a Baseload Facility Whenever Economically Feasible to Do So</u>

Q. How does PSE intend to utilize the Mint Farm Energy Center?

A. As discussed in the prefiled direct testimony of Mr. Ed Odom, Exhibit No. ___(LEO-1CT), the Mint Farm Energy Center is designed to run at a baseload capacity factor above 90%, and PSE intends to operate it in that manner whenever it is economically feasible to do so. Actual operations of the Mint Farm Energy Center will vary based on its ability to be dispatched economically, which is discussed in more detail in the prefiled direct testimony of Mr. David Mills, Exhibit No. ___(DEM-1CT). Economic dispatch typically increases the use of more efficient generating units, which leads to better fuel utilization, lower fuel usage, and reduced air emissions that would come from less efficient generation. With the Mint Farm Energy Center's advanced gas turbine technology and its low heat rate, the plant is among the most efficient in the WECC region.

4. <u>Estimated Costs in Calendar Year 2009 for the Mint Farm Energy Center Provide an Example of the Cost Deferral Requested</u>

Q. What are the fixed and variable costs of the Mint Farm Energy Center that PSE seeks to defer?

A. Please see Exhibit No. ___(WJE-18) for projected total fixed costs of the Mint Farm Energy Center that PSE seeks to defer, and please see Exhibit No. ___(WJE-19) for projected net variable costs of the Mint Farm Energy Center that PSE seeks to defer. These exhibits reflect the authorization given PSE to defer the fixed (including the return of and on the plant investment) and variable cost components associated with the Mint Farm Energy Center in the Settlement Stipulation filed with, and approved by, the Commission in Docket No. UE-082128. The costs reflected in Exhibit No. ___(WJE-18) and in Exhibit No. ___(WJE-19) are projections intended to provide an example of deferral costs for calendar year 2009. PSE will base the actual deferral upon actual costs.

B. The Sumas Cogeneration Station Complies With the Greenhouse Gases Emissions Performance Standards in RCW 80.80

1. The Commission Previously Determined that PSE Acted Prudently in Its Acquisition of the Sumas Cogeneration Station

Q. Has the Commission previously determined that PSE acted prudently in its acquisition of the Sumas Cogeneration Station?

A. Yes. In PSE's previous general rate proceeding in Dockets UE-072300 and UG-072301, the parties[1] entered into an All-Party Settlement of Electric and Natural Gas Revenue Requirements. Pursuant to such partial settlement agreement, the settling parties agreed and stipulated (i) that PSE acted prudently in the acquisition of the Sumas Cogeneration Station and (ii) that the Commission should approve the costs associated with the Sumas Cogeneration Station for recovery in rates. In its Order 12, Final Order Approving and Adopting Settlement Stipulations; Authorizing and Requiring Compliance Filing, in Dockets UE-072300 and UG-072301, the Commission approved and adopted the All-Party Settlement of Electric and Natural Gas Revenue Requirements, among other settlement stipulations.

[1] The parties to Dockets UE-072300 and UG-072301 that entered into the All-Party Settlement of Electric and Natural Gas Revenue Requirements were PSE, Commission Staff, the Public Counsel Section of the Attorney General's Office, the Industrial Customers of Northwest Utilities, Northwest Industrial Gas Users, Seattle Steam Company, The Energy Project, The Kroger Co., Federal Executive Agencies, and Nucor Steel Seattle, Inc.

2. The Sumas Cogeneration Station is Designed to Run as a Baseload Facility, and PSE Intends to Operate It as a Baseload Facility Whenever Economically Feasible to Do So

Q. How does PSE intend to utilize the Sumas Cogeneration Station?

A. As discussed in the prefiled direct testimony of Mr. Ed Odom, Exhibit No. ___(LEO-1CT), the Sumas Cogeneration Station is designed to run at a baseload capacity factor above 90%, and PSE intends to operate it in that manner whenever it is economically feasible to do so. Actual operations of the Sumas Cogeneration Station will vary based on its ability to be dispatched economically, which is discussed in more detail in the prefiled direct testimony of Mr. David Mills, Exhibit No. ___(DEM-1CT). Economic dispatch typically increases the use of more efficient generating units, which leads to better fuel utilization, lower fuel usage, and reduced air emissions that would come from less efficient generation.

VII. CONCLUSION

Q. Please summarize your conclusions.

A. PSE purchased the Mint Farm Energy Center at a cost that was nearly $500/kW less than the cost of a new combined cycle plant. Even with updating of costs, the Mint Farm Energy Center produces a benefit to the PSE portfolio of approximately $34.5 million.

The Barclays Four-year Winter PPA produces a benefit to the PSE portfolio of approximately $25 million. Not only was the Barclays Four-year Winter PPA lower than the cost of generic resources, but the final pricing of the Barclays Four-year Winter PPA was the best of competitive offers from three pre-qualified bidders.

The Wild Horse Wind Project is projected to produce a benefit to the PSE portfolio of approximately $3 million. In addition, the Wild Horse Wind Project may have even lower costs because of potential benefits provided in the Stimulus Bill.

The Nooksack Hydro Five-Year PPA produces a benefit to the PSE portfolio of approximately $272,000. Additionally, the Nooksack Hydro Five-Year PPA contributes RECs for PSE's Green Power Program.

The Qualco Energy Dairy Digester Five-year PPA produces energy fueled by methane from dairy herd waste and is a reasonable contract for renewable energy priced effectively at tariff rates. Although this PPA was too small for a PSM analysis, PSE estimates that the Qualco Energy Dairy Digester Five-year PPA produces a benefit to the PSE portfolio of approximately $80,000.

The Credit Suisse Four-year Market PPA that replaced the PPA with Lehman Brothers was an effective replacement that actually reduced PPA costs by about $1.05 per MWh.

PSE has a need for Fredonia Gas Turbine Units No. 3 and No. 4, which are the newest and most efficient peaking generation units in PSE fleet. Replacing these units with more efficient peaking units could increase capital costs to customers by over 2.5 times.

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.