Exhibit No. DN-1THC
Dockets UE-090704/UG-090705
Witness: David Nightingale
REDACTED VERSION
Revised November 19, 2009

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	DOCKET UE-090704 DOCKET UG-090705

TESTIMONY

OF

DAVID NIGHTINGALE

STAFF

OF

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Prudence of Electric Generation Resources, and Mint Farm and Sumas Greenhouse Gas Emissions Standard Compliance

November 17, 2009
Revised November 19, 2009

HIGHLY CONFIDENTIAL PER PROTECTIVE ORDER – REDACTED VERSION

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EXHIBIT LIST

Exhibit No. DN-2	July 9, 2009 Letter from Department of Ecology to Puget Sound Energy Addressing Compliance by the Sumas CCCT with the GHG Emissions Performance Standard

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David Nightingale. My business address is the Richard Hemstad Building, 1300 South Evergreen Park Drive SW, Olympia, Washington, 98504-7250.

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

A. I am employed by the Washington Utilities and Transportation Commission ("Commission") as a Senior Regulatory Engineering Specialist. I have held that position since February 2009.

Q. What are your duties as a Senior Regulatory Engineering Specialist?

A. My current duties involve analysis of issues related to Commission regulation of electric utilities, including integrated resource planning, requests for proposals, greenhouse gases emissions performance standard compliance, and power supply acquisition, and providing that analysis to the Commission. I have testified before the Commission in support of a settlement in Docket UE-090205 (PacifiCorp) on generation resource prudence and greenhouse gas emissions compliance.

Q. Please describe your education and relevant employment experience.

A. I hold a Bachelor of Arts degree in Business Administration from Western Washington University, Bellingham. I also hold a Bachelor of Science degree in Energy Engineering from the University of Washington, Seattle, where my studies

focused on fluid-dynamics, thermo-dynamics, and alternative energy. I performed research and designed projects, including testing residential conservation standards in four fully-instrumented model homes (this research led to the technical justification for what became the Super Good Cents program), cost-effectiveness of residential solar hot water heating, and design of a small wind turbine system on Orcas Island.

From 1987 to 1991, I worked for RW Beck and Associates, an engineering consulting firm in Seattle. I worked on county and state waste and recycling system planning, landfill development, and waste-to-energy (renewable biomass) project evaluation and analysis for clients in Washington and Alaska.

From October 1991, through January of 2009, I worked for the Washington State Department of Ecology ("Ecology") in various capacities; as a planner, engineer, technical unit supervisor, statewide technical-lead, and policy staff. My projects included technical review and regulatory compliance of renewable biomass projects, such as landfill gas to energy projects, variously-fueled pyrolysis plants and proposals, and fluidized-bed and mass-burn waste-to-energy plants. I was also responsible for technical review and regulatory assistance for coal combustion products recycling and disposal options for TransAlta's Centralia power generation plant, as well as combustion products disposal for Avista's Kettle Falls wood-fueled electric generating plant.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. Please explain the purpose of your testimony.

A. Puget Sound Energy, Inc.'s ("PSE" or "the Company") has asked the Commission to determine that it was prudent for the Company to acquire the Mint Farm Generating Center ("Mint Farm"), Fredonia Units 3 and 4, and the expansion of the Wild Horse wind project ("Wild Horse"). The Company seeks a similar prudence determination regarding its new power purchase agreements ("PPAs") with Credit Suisse, Barclay's Bank, Puget Sound Hydro, and Qualco Energy. My testimony addresses the Company's requests.

I also examine whether Mint Farm is "baseload electric generation" that qualifies for automatic deferred cost accounting. Finally, I respond to PSE's request for a Commission determination that Mint Farm and the Sumas combined-cycle combustion turbines ("CCCT") comply with the greenhouse gas ("GHG") emissions performance standard of RCW 80.80. The Sumas CCCT was previously determined by the Commission to be a prudent acquisition, but no GHG compliance determination has yet been made.[1]

In my testimony, I refer to various statutes and rules. In doing so, I provide my understanding of these laws and rules in my capacity as a Regulatory Specialist.

Q. Please summarize your conclusions on the issues addressed in your testimony.

A. I conclude that the Company's acquisition of Mint Farm, Fredonia Units 3 and 4, the Wild Horse expansion, and all PPAs are all prudent under Commission-established standards. I also conclude that Mint Farm constitutes "baseload electric generation" that qualifies for automatic deferred accounting. Staff witness Martin addresses the specific deferred accounting proposal made by PSE.

[1] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-072300, Order 12 at ¶59 (October 8, 2008).

Finally, I conclude that Mint Farm and the Sumas CCCTs comply with the applicable GHG emissions performance standard of 1100 pounds per MWh.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. Exhibit No. DN-2 is a July 9, 2009 letter from Department of Ecology to PSE addressing compliance by the Sumas CCCT with the GHG emissions performance standard.

Q. Please briefly describe the Mint Farm and Sumas plants.

A. Mint Farm is a ~~six~~-two year old, ~~520~~ 311 MW natural gas-fired electric generation facility located in Longview, Washington, which is in the Company's service territory. It consists of ~~two~~ a combustion gas turbine generators which feeds into a ~~single~~ steam turbine generator, and related equipment. PSE purchased the facility on December 5, 2008 and is the sole owner of the plant. The plant is operational.

The Sumas CCCT is an existing combined-cycle combustion turbine located at Sumas, Washington. It has a capacity of approximately 125 MW and was purchased by PSE on July 25, 2008.

Sumas was originally built in the early 1990s and employs an older frame combustion turbine in combination with a steam turbine that has a higher heat rate than Mint Farm.

Q. What does the term "heat rate" mean?

A. Heat rate is the ratio of the amount of heat energy (in the case of natural gas measured in the units of Million British Thermal Units (MMBtus)) that is required to produce a Megawatt hour (MWh) of electrical energy. For natural gas, one MMBtu is approximately equivalent to one Decatherm (10 therms), or the heat from burning 1,000 cubic feet of natural gas. A plant with a higher heat rate requires more fuel (heat energy input) to produce one MWh of electric energy. The fuel (heat energy) is the variable in the heat rate calculation, whereas the denominator is always the same, one MWh of electric energy.

Heat rate values for a simple-cycle combustion turbine might be expected to be in a 9 to 11 MMbtu (heat) per MWh (electricity) range. For a combined-cycle combustion turbine system, the heat rate range might be 6.5 to 7.5 MMbtu per MWh. A plant with a higher heat rate will require the purchase of more fuel for the same amount of energy to be produced. Consequently, in general, energy producers save operating costs by running lower heat rate plants before using higher heat rate plants.

Q. How does this discussion of heat rate apply to Sumas and Mint Farm?

A. Because Sumas has a higher heat rate than Mint Farm, the Company will typically run Mint Farm before running Sumas. However, either of these combined-cycle plants will more likely be run before any simple-cycle peaker plant because of the lower heat rates of combined-cycle technology. This economic reality explains why natural gas electric generating peakers are characterized by simple-cycle combustion turbine plants and baseload plants are characterized by combined-cycle combustion turbine plants. It is uneconomic to run simple-cycle plants very much or for very

long, except during peak load demand periods when the market cost of electricity is relatively high.

Q. Please briefly describe the Wild Horse expansion project.

A. The expansion adds to PSE's existing Wild Horse wind farm and solar electric generating plant located eleven miles east of Kittitas, Washington. The Wild Horse expansion consists of 22 additional Vestas V80-2.0 MW wind turbines with an additional combined nameplate capacity of approximately 44 MW. The expansion became operational in November 2009.

Q. Please briefly describe the Fredonia gas turbine generation facility.

A. The Fredonia gas turbines are two-54 MW simple-cycle natural gas-fired combustion turbines ("CT") which PSE has leased since 2001. The Company refers to these CTs as Fredonia Units 3 and 4. In November 2008, the lessor provided notification of its intent to terminate the lease in 60 days. PSE chose to exercise its purchase option for the CTs, which will occur in about January 2010. These CTs provide peaking capacity and energy to the PSE system. They are also the newest PSE CTs with the lowest heat rate in the Company's peaker fleet.[2]

Q. Please briefly describe the Power Purchase Agreements.

A. The PPAs are contracts executed by PSE with four different counterparties:

[2] Garratt Exhibit No. RG-1HCT at 60-63.

1. An October 2008 agreement to purchase winter (November-February) power up to 75 MW/Hr from Barclays Bank delivered to Mid-C for four years beginning November 2012.[3]

2. A September 2008 agreement to purchase the entire output and renewable energy credits from a 1.5 MW hydro plant owned by Puget Sound Hydro, LLC, directly connected to the PSE system near Glacier, Washington on the North Fork of the Nooksack River for five years and one month, ending on the end of the last day of December 2013.[4]

3. A March 2009 agreement to purchase all power, 450 kilowatts, and a January 2009 agreement to purchase all renewable energy credits for five years, both from Qualco Energy, a biomass methane generator and energy production company located in Monroe, Washington, and delivery of energy by wheeling through Snohomish County PUD.[5]

4. An agreement with Credit Suisse executed on September 16, 2008 in response to a small RFP to replace an agreement with Lehman Brothers immediately following its bankruptcy filing.[6] The Credit Suisse bid was most favorable and involves delivery of up to 50 MW of power for 4 years, three months beginning January 1, 2009 at Mid-C.[7]

Q. What information did you evaluate in conducting your analyses in this case?

A. I reviewed the direct testimony and exhibits of PSE witnesses Markell, Mills, Elsea, Valdman, Garratt, Riding, Henderson, Harris and Odom, and I reviewed PSE's responses to over 90 data requests. I also reviewed the Company's 2007 Integrated Resource Plan ("IRP"), its Request for Proposals ("RFP") analyses, the transaction documents, plant design and operations documents, and many other related documents. I also reviewed various statutes and rules, and documents related to the Commission's (Docket UE-080111) and Ecology's GHG rulemaking processes.

[3] Garratt Exhibit Nos. RG-16 and RG-17C.
[4] Garratt Exhibit Nos. RG-18C and RG-19C.
[5] Garratt Exhibit Nos. RG-20C and RG-21C.
[6] Garratt Exhibit No. RG-1HCT at 57.
[7] Garratt Exhibit No. RG-25C.

I also visited the Wild Horse generation site on one of the days when the new wind turbines were delivered and installed. Staff also performed a site visit to Mint Farm after it had been upgraded and brought back on line in early 2009.

Finally, a working session was held with PSE staff to review the methodology and findings of their analyses of alternatives, focusing on their use of the Portfolios Screening Model ("PSM"). This session was conducted on August 4 and 6, 2009 at Olympia.

Q. Before proceeding further, please briefly describe what IRPs and RFPs are, and the related processes.

A. The IRP projects the utility's likely future resource needs for the next 20 years, as well as the most advantageous types of resources to acquire in order to meet those needs. In addition to acquisition of generating resources, the IRP also calls for a blend of demand side management and market purchases to serve the needs of the Company's customers. The utility develops its IRP in consideration of a balanced acquisition of both supply and demand–side resources through a public process. As part of the resource acquisition process, the Company issues an RFP to seek bids from resource suppliers. In this instance, PSE issued an RFP in January 2008 for All Generation Sources and Demand Side Resources.

III. DISCUSSION

A. Used and Useful for Service

Q. What is the importance of the "used and useful" for service issue?

A. It is my understanding that in order for a resource to be included in rate base for ratemaking purposes, the resource must be "used and useful for service" in Washington State.[8] The Commission has stated that the phrase "used and useful for service in this state" means "to benefit the ratepayers of Washington, either directly (*e.g.*, flow of power from a resource to customers) and/or indirectly (*e.g.*, reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[9] The Commission also has stated that "the [c]ompany must demonstrate tangible and quantifiable benefits to Washington of resources in the system before we will include the resources in rates."[10]

Q. Are the newly acquired facilities (Mint Farm, Wild Horse Expansion, and the Fredonia gas turbines) used and useful for service in Washington?

A. Yes. These facilities are operating, and are currently directly providing a "flow of power from a resource to customers." All facilities are located in Washington and are directly connected to PSE's system or the BPA transmission in Western Washington. All are available to provide power to the Company's service territory.

[8] RCW 80.04.250.
[9] *WUTC v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Docket UE-050684, Order 04 at ¶ 50 (April 17, 2006).
[10] *Id.* at ¶ 68.

In the prudence discussion that follows, there are additional analyses that address the question of benefits to ratepayers that are tangible and have been quantified by PSE and verified during my review of the relevant documents. These analyses focus on the Company's direct case and its responses to various data requests.

B. The Prudence of PSE's Acquisition of Mint Farm, Wild Horse Expansion, Fredonia, and PPAs

1. Prudence Standard

Q. What is the Commission's prudence standard?

A. The Commission applies a prudence standard when it determines whether a particular resource acquisition decision by a utility was appropriate, and therefore the ratepayers can be required to support that asset through rates. Overall, the prudence standard is a reasonableness standard:

> The Commission has consistently applied a reasonableness standard when reviewing the prudence of decisions relating to power costs, including those arising from power generation asset acquisitions. The test the Commission applies to measure prudence is what would a reasonable board of directors and company management 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.[11]

[11] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 19 (April 7, 2004) (footnotes and related citations omitted).

Q. What factors does the Commission use to evaluate the prudence of a utility's electric resource acquisition?

A. There is no single set of factors. For example, in Cause U-83-26, the Commission applied thirteen factors, which the Commission characterized as "unique" and stated that "[a]dditional factors may be considered in subsequent cases as dictated by the facts."[12] In subsequent cases, the Commission and its Staff[13] have generally focused on the following four factors:

1) *The Need for the Resource* - The utility must first 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.[14]

2) *Evaluation of Alternatives* - The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.[15]

3) *Communication With and Involvement of the Company's Board of Directors* - 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.[16]

4) *Adequate Documentation* - The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making 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.[17]

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[12] *WUTC v. The Wash. Water Power Co.*, Cause U-83-26, Fifth Supplemental Order at 15-16 (January 19, 1984).
[13] *E.g., WUTC v. Puget Sound Energy, Inc.*, Docket UE-070565, Testimony of Douglas Kilpatrick, Exhibit 117 at 3:18-5:9.
[14] *WUTC v. Puget Sound Power & Light Co.*, Docket UE-921262, *et al.*, Nineteenth Supplemental Order at 11 (September 27, 1994).
[15] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 20 (April 7, 2004).
[16] *Id.*
[17] *Id.* at ¶ 20.

Implicit in the prudence standard is the notion that the facility in question needs to comply with applicable state laws. This has specific relevance to Mint Farm because of recent legislation regarding GHG emissions and renewable portfolio standards ("RPS"). I discuss these statutes later in my testimony.

In my opinion, it is appropriate to apply all of these factors in this case.

2. Application of the Prudence Standard- Mint Farm

a. The Need for the Resource; Evaluation of Alternatives; Cost

Q. Does the Company adequately support the need for Mint Farm and prove that this plant was the appropriate resource to acquire to meet that need?

A. Yes. The direct testimony and exhibits of Company witnesses Elsea, Garratt, Henderson, Mills, Riding, and Odom provide this support. I confirmed their analysis through my evaluation of available information.

In short, Mint Farm fulfills a need specified in the Company's 2007 IRP, and the Company considered many alternative resource options as part of its 2008 RFP evaluation process. In preparing for the 2008 RFP process, the 2007 IRP demand forecast was updated and found that there were energy needs for 143 aMW by 2011, 700 aMW by 2012, and 977 aMW by 2013. Similarly, there were significant capacity needs as follows: 208 MW by 2011, 760 MW by 2012, and 771 MW by

2013.[18] The 2007 IRP indicates that the majority of this energy capacity need will be met from 2008 forward by the acquisition of new CCCT generating capacity.[19]

Q. Please describe the 2008 RFP process more fully and how that lead to the choices the Company made to acquire new resources such as the Mint Farm.

A. The 2008 RFP solicitation resulted in 31 project proposals including PPAs, ownership offers, and combinations (partial ownership) for coal, gas-fired turbines, hydro, wind, and unspecified resources. PSE employed a two-phase due diligence process. Phase I was a screening process to eliminate projects that were deemed to be infeasible or clearly involved high cost or high risk. This resulted in a list of candidate proposals for further evaluation in Phase II. The Company then ranked the Phase II candidate proposals, which resulted in a final short list. PSE then began pursuing available projects from the final short list.

Q. Please elaborate on your explanation of PSE's resource evaluation process.

A. In Phase I of the RFP evaluation, PSE's analysis involved extensive review of projects including vendor interviews, data requests, use of an outside consultant, and 18 internal teams of subject experts to evaluate all facets of each proposal. This extensive and detailed analysis evaluated the Mint Farm proposal along with other potential plant purchases, as well as the cost to self-build a similar plant and other resources. The Company also ran the PSM to evaluate each proposal in the same way, and to assess how each proposed resource fit into the rest of the existing PSE

[18] Elsea Exhibit No. WJE-3.
[19] Harris Exhibit No. KJH-5 at 218 and 219 (2007 IRP, pages 8-2 and 8-3).

portfolio and to estimate their costs and benefits compared to the generic resource modeling from the 2007 IRP. As part of its due diligence, the Company retained an independent consultant to evaluate the wind proposals compared with a similar set of assumed inputs.

From the Phase I analysis, 13 proposals passed on to Phase II of the evaluation process based on their relatively strong operational characteristics, as well as minimization of cost and risk. This included five natural gas plants, four PPAs, and four wind projects. During Phase II, PSE also updated the estimated costs of generic resources to reflect market changes. The Company found that the cost of acquiring generic wind and generic combined-cycle combustion turbines had increased to about $2,760/kW and $1,330/kW, respectively, for plants to be delivered in 2010.[20]

Phase II involved further modeling with the PSM with updated assumptions, updates to the AURORA long-term energy price forecast model, and additional qualitative and quantitative investigation and analysis of technical, financial, environmental, and other due diligence factors.[21] The result of Phase II was a final short list of resources for negotiation purposes. In addition, PSE categorized the remaining proposals as either "monitoring/possible future negotiations", or "projects dropped" from further consideration. This allowed PSE to access the next most promising proposals as the need might arise or negotiations failed with the final short list candidates.

[20] Garratt Exhibit No. RG-3HC at 179.
[21] Garratt Exhibit No. RG-3HC at 108-146 and 176-204.

Q. How did Mint Farm fare in this evaluation process?

A. Mint Farm was favorable enough compared to all other alternatives to be placed on the final short list. Importantly, the evaluation demonstrated that Mint Farm had:

- a relatively low 20-year levelized cost compared to other CCCTs;
- a low heat rate (BTU/kWh) compared to other CCCTs;
- pre-existing electric transmission rights on BPA lines in Western Washington;
- available gas transmission and supply;
- a relatively new plant with good maintenance; and
- the ability to follow load that can be used to complement wind resources.

The analysis showed that the purchase of Mint Farm had significant value in terms of reducing future cost increases, lowering risk of counterparty default (it was an existing, operational facility), meeting energy and capacity needs for the future, and providing the flexibility to meet variable loads including integrating wind resources.

Q. Are resources such as a CCCT available to acquire in a way that exactly meets the need of customer demand?

A. No. CCCT plants are "lumpy" in that they become available in large blocks of capacity in a timeframe that is often not perfectly matched to load demand. Mint Farm, [redacted] and the [redacted] are the only such resources that were potentially available for acquisition in or near PSE's service territory during the RFP evaluation process. [redacted] is approximately the same capacity as Mint Farm, but is

an older design with a higher heat rate. The [redacted] is significantly larger in capacity than Mint Farm or [redacted], but does not have available transmission capacity in the next few years. Although it would have been possible for PSE to continue meeting demand through existing resources and additional market purchases in 2008, the 2007 IRP demonstrated a need for a CCCT-type resource at or before the 2011 timeframe.[22] This need was reaffirmed in early 2008 by PSE staff.[23]

Q. Was the price PSE paid for Mint Farm reasonable?

A. Yes. The capacity price paid for Mint Farm was significantly below the ~~of~~ $1,330/kW ~~was significantly below~~ market price determined by PSE during the RFP process for a generic CCCT resource.[24] The Company used the generic CCCT resource market price estimate as an approximate self-build option to compare to the price of Mint Farm.

Due to financial constraints of the prior owners, Mint Farm was left partially completed for a period of years and, when completed, run little prior to PSE's purchase. Construction began in 2001, but was not completed until 2007. CCCTs have an expected life of 25-30 years or more with good maintenance. The actual use of Mint Farm was equivalent to approximately one year at the time PSE purchased the plant. PSE hired a professional consulting firm to evaluate the condition of all of the plant's critical systems prior to purchasing the plant. The overall condition of the plant was good considering its age and use. PSE was able to take advantage of this financially distressed plant at a discounted purchase price on a $/kW capacity basis.

[22] Harris Exhibit No. KJH-5 at 79 (May 2007 PSE IRP, page 5-2).
[23] Elsea Exhibit No. WJE-3.
[24] Garratt Exhibit No. RG-3HC at 179.

This plant is one of only a few operational gas turbines that are not already owned by other utilities. PSE's IRPs indicate the likely need to acquire additional CCCT plants in the near future even after the acquisition of Mint Farm. These future plants are most likely yet to be built and therefore are expected to require higher levels of cost per capacity than Mint Farm.

In summary, the price PSE paid for Mint Farm was very reasonable, and considerably below contemporaneous estimates of market price for similar plants based on $/kWh capacity.

b. Participation of the Company's Board of Directors

Q. Did PSE's Board of Directors make the final decision to acquire Mint Farm?

A. Yes, the final decision to acquire Mint Farm was made by the PSE Board. This was well documented in the testimony of Company witness Garratt.[25] The PSE Board received a large amount of materials to review, and extensive presentation and analysis from PSE staff, to make a reasoned decision on the purchase of Mint Farm.

c. Documentation of the Company's Decision-Making Process

Q. Did PSE keep adequate contemporaneous records that allow the Commission to evaluate the Company's decision-making process?

[25] Garratt Exhibit Nos. RG-7HC and RG-8.

A. Yes. PSE provided adequate documentation of both management and Board of Director decision-making processes through memos, reports, presentations given to the decision-makers, and resolutions of PSE's Board.[26]

d. Compliance with the Greenhouse Gases Emissions Performance Standard[27]

Q. What is the GHG emissions performance standard?

A. As it applies in this case, the GHG performance standard is "one thousand one hundred pounds of greenhouse gases per megawatt-hour."[28] This standard must be met by an [1] "electrical company" that acquires [2] "baseload electric generation" via a [3] "long-term financial commitment" [4] "after June 30, 2008."[29] As RCW 80.80.060(1) states: "No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse gases emissions performance standard."

Q. Is the Mint Farm generating plant subject to this standard?

A. Yes. PSE qualifies as an "electrical company" because that term means "a company owned by investors that meets the definition of RCW 80.04.010,"[30] which in turn

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[26] *Id.*

[27] While GHG emissions compliance is an element of the Mint Farm prudence review, I also address in this section of my testimony PSE's request for a GHG compliance determination for Sumas even though there is no prudence issued raised in this case for Sumas.

[28] RCW 80.80.040(1)(a). According to the statute, this is the applicable standard until the Washington Department of Commerce (formerly the Department of Community, Trade and Economic Development) develops a different standard, a process that begins in 2012. RCW 80.80.040(1)(b) and 80.80.050.

[29] RCW 80.80.040(1).

[30] RCW 80.80.010(12).

defines electric companies subject to Commission regulation. PSE acquired Mint Farm via a "long-term financial commitment" "after June 30, 2008" and a "long-term financial commitment" includes "a new ownership interest."[31]

Mint Farm is "baseload electric generation," as I explain later in my testimony. Therefore, I conclude that Mint Farm is subject to the GHG performance standard of less than 1,100 pounds per megawatt hour of energy generated.

Q. Does Mint Farm comply with that GHG performance standard?

A. Yes. A letter dated December 17, 2008 from Sarah Rees of Ecology states that Mint Farm emits less than 1,100 pounds of GHG emissions per megawatt hour, and, therefore, meets the GHG emissions performance standard.[32] I verified this finding and the methods used with Ecology staff. Therefore, I conclude that Mint Farm meets the GHG emissions performance standard.

Q. Is it necessary for the Commission to determine expressly whether or not Sumas meets all of the statutory elements to require compliance with the GHG emissions performance standard?

A. No. My Exhibit No. DN-2 is a letter dated December 17, 2008 from Sarah Rees of Ecology stating that the Sumas plant meets the GHG emissions standard.[33] We recognize Ecology's authority and role in that determination. Therefore, Sumas

[31] RCW 80.80.010(15).
[32] Henderson Exhibit No. JHM-5.
[33] Exhibit DN-2.

meets the GHG emissions performance standard, regardless of whether it meets all statutory factors that would require it to meet that standard.

In contrast, it is necessary for the Commission to assess whether Mint Farm meets the statutory prerequisite of being baseload electric generation because ~~such~~ automatic deferred accounting is permitted by RCW 80.80.060 only if Mint Farm is baseload electric generation.

e. Other Mint Farm Prudence Issues

Q. Are there any other issues regarding the prudence of PSE's acquisition of Mint Farm?

A. Yes. Based on the Company's direct testimony and response to Staff Data Request No. 177, PSE's pre-purchase evaluation of the Mint Farm property was limited to hazards associated with the subsurface exploration required to structurally support the plant on weak soils and soils that may become liquefied during an earthquake.[34] Although the Columbia River is located within ½ mile of the site and the topology from the river to the Mint Farm site is flat,[35] the Company failed to assess the current condition of the dike system that protects the plant from normal flood events.

Q. What should the Commission order to remedy this shortcoming?

A. PSE should be ordered to perform a flood potential hazard assessment to discover the condition of the current dike system that protects the Mint Farm property from

[34] PSE Response to Staff Data Request No. 177, Attachment A at 1.
[35] *Id.*

flooding. PSE should also be required to develop a flood contingency plan and determine any actions needed to assure that the property will not be flooded and any future financial obligations that PSE may be subject to from such actions.

f. Conclusion on Mint Farm Prudence

Q. What is your conclusion regarding the prudence of PSE's acquisition of Mint Farm?

A. Notwithstanding the deficiencies in PSE's pre-purchase flood potential assessment at the Mint Farm site, the documents I reviewed and the analysis I conducted demonstrate that PSE's decision to acquire Mint Farm was prudent. My recommendation that the Company provide reports on flood potential does not dissuade me from that conclusion.

3. Application of the Prudence Standard- Wild Horse Expansion

Q. Do the prudence standards you applied to Mint Farm also apply to your analysis of PSE's acquisition of the Wild Horse expansion?

A. Yes.

Q. Are there any significant differences in your analysis of the Wild Horse expansion?

A. Yes. As I explain below, the statutory compliance factor for Wild Horse relates to the Renewable Portfolio Standard ("RPS"). Renewable resources such as Wild Horse are

deemed to comply with the GHG emissions performance standard,[36] so I need not address that issue further.

a. The Need for the Resource; Evaluation of Alternatives; Cost

Q. Does the Company adequately support the need for the Wild Horse expansion, and demonstrate that the expansion was the appropriate resource to acquire to meet that need?

A. Yes. The direct testimony and exhibits of Company witness Harris provides this support from the 2007 IRP. The Wild Horse expansion is consistent with PSE's 2007 IRP goal of pursuing a least-cost strategy focusing on the acquisition of three specific resource types: 1) cost-effective conservation; 2) an increasing reliance on wind development to meet the RPS and 3) CCCT plants for the balance of new acquisitions to meet forecasted energy and capacity needs.[37] This energy resource strategy includes the addition of nameplate wind generating capacity of at least 550 MW by 2015 and 921 MW by 2020. The expansion of Wild Horse is consistent with this general planning context and supports this strategic direction.

Due diligence was conducted on the expansion site including analysis of site meteorological wind data, technology of the new larger capacity Vestas turbines, and approvals from local, state and federal permitting authorities before committing to developing the expansion site.[38]

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[36] RCW 80.80.040(3).
[37] Harris Exhibit No. KJH-5 at 218 (2007 IRP, page 8-2).
[38] Garratt Exhibit No. RG-1HCT at 76-78.

The opportunity to expand Wild Horse was undertaken after the 2007 IRP and before the 2008 RFP process began. Nevertheless, the acquisition was evaluated using the same modeling approaches, variables, and standards as the process for the 2008 RFP evaluation process.[39]

The acquisition of the Wild Horse expansion stemmed from a proposal from the Whiskey Ridge Power Partners LLC. Starting in June 2007, PSE investigated the proposal using a detailed financial and technical evaluation and comparison of other renewable projects that were available at the same time. This included use of the PSM to compare Wild Horse to other wind and geothermal acquisition options as of January 2008.[40] Although there were three other projects that ranked higher than the Wild Horse expansion proposal, all three became unavailable before PSE was able to acquire them. Consequently the Wild Horse expansion project was the best remaining project available. PSE decided to first acquire the development rights and then to construct the expansion.

Q. Was the price PSE paid for the Wild Horse expansion project reasonable and related to the timing of the project's development?

A. Yes. The price of the Wild Horse expansion was cost competitive and was at or slightly better than the estimated cost of the generic wind resource evaluated in the 2007 IRP. The decision to move forward with the expansion was influenced by the expiration of Federal production tax credits for projects that were not placed in service before December 31, 2009. Also influential was a Washington state sales tax

[39] Elsea Exhibit No. WJE-1HCT at 24-25, and PSM workshops with PSE staff (August 4 and 6, 2009).
[40] Elsea Exhibit No. WJE-1HCT at 34-35.

exemption for wind turbines and other renewable energy generators, if acquired by June 20, 2009. The availability of PSE's transmission and existing interconnection from the Wild Horse wind farm also helped to reduce both the per-unit cost and the risk of development.

Q. Is there a risk of over-building wind resources at higher than necessary costs with PSE's current accelerated rate of acquisition of renewable energy resources?[41]

A. Yes, there is a potential for acquiring more than the required level of renewable wind at costs higher than other resources. This may happen if the cost of acquiring wind resources significantly increases or other resources become relatively less expensive. Scenarios that could cause significant cost increases include wind turbine equipment price increases, increased cost of development rights to the best wind sites, and elimination of tax incentives. Decreases in development costs of CCCT generator plants, while unlikely, could also make wind farms less favorable economically.

With current market conditions, wind farm acquisition capital costs are about twice that of a CCCT based on a comparison of dollars per KW of installed capacity.[42] However, wind farms have no fuel costs and low maintenance

[41] PSE's corporate goal is to meet 10 percent of its resource needs with renewable energy by 2013. Company Response to Staff Data Request No.176 at 1. This goal exceeds the statutory renewable requirement of nine percent by 2016 and 15 percent by 2020. RCW 19.285.040(2)(a).
[42] Elsea Exhibit No. WJE-11HC at 3.

requirements. As a result, the 20-year levelized cost of wind power is [redacted] the per MWh cost of a CCCT power. This was shown in the results of PSE's 2008 all sources RFP evaluation.[43]

Because wind and other generating resources require years to develop and have long service lives of 25 to 30 years or more, it is necessary to make commitments based on long-term projections of costs and benefits, such as the 20-year levelized cost. In addition, the Company's 10 percent corporate goal was included in merger Commitment 49 in Docket U-072375, if it can be met economically and is necessary to meet load energy requirements.

b. Participation of the Company's Board of Directors

Q. Did PSE's Board of Directors make the final decision to develop the Wild Horse expansion?

A. Yes. The PSE Board was presented with all appropriate information to make this decision, as shown in Company witness Garratt's Exhibit Nos. RG-39HC and RG-40.

Q. What do you conclude from these facts?

A. PSE satisfied all of the applicable prudence factors and the decision to proceed toward ultimate acquisition of this new renewable resource was made by the PSE Board of Directors. Therefore, I conclude that the Wild Horse expansion was a

[43] Elsea Exhibit No. WJE-11HC at 10.

reasonable choice for a renewable resource acquisition by PSE when that decision was rendered.

c. Documentation of the Company's Decision-Making Process

Q. Did PSE meet the documentation requirement for the Wild Horse expansion?

A. Yes. PSE provided adequate contemporaneous records of its decision-making process and supporting analysis presented to the Board regarding the Wild Horse expansion. These contemporaneous records are included in Exhibit Nos. RG-39HC and RG-40.

d. Compliance with the Renewable Portfolio Standard

Q. What is the Renewable Portfolio Standard?

A. The RPS is contained in the Energy Independence Act, RCW 19.285. In part, the RPS requires certain electric utilities to acquire eligible renewable resources, and/or equivalent renewable energy credits, at the following levels and time schedule:

(i) At least 3 percent of load by January 1, 2012, and each year thereafter through December 31, 2015;

(ii) At least 9 percent of load by January 1, 2016, and each year thereafter through December 31, 2019; and

(iii) At least 15 percent of load by January 1, 2020, and each year thereafter.[44]

[44] RCW 19.285.040(2)(a).

Q. Is PSE subject to the RPS?

A. Yes. PSE meets the definition of a "qualifying utility" because it meets the 25,000 customer threshold.[45]

Q. Is the Wild Horse expansion an eligible resource for purposes of the RPS?

A. Yes. Wind power in on the list of eligible renewable resources.[46] The Wild Horse expansion also meets the requirement that an eligible resource commence operation after March 31, 1999.[47] The Wild Horse expansion became fully operational on November 9, 2009. Lastly, the resource meets the geographic requirement of location in the "Pacific Northwest," or that the output be delivered there. Wild Horse is located in Washington and Washington is in the area defined as "Pacific Northwest".[48]

Q. Is PSE making progress towards RPS compliance?

A. Yes. The Wild Horse expansion project will add to the Company's renewable resource portfolio and further the Company's progress to meeting the RPS. PSE has forecasted that the cost per MWh of energy from a generic wind resource will be less than the equal amount of energy from a CCCT. Because there are unknowns about the future cost of carbon emissions and wind turbines, as well as the value of renewable energy credits, that prediction may change in the future. At this point in

[45] RCW 19.285.030(16).
[46] RCW 19.285.030(18)(b).
[47] RCW 19.285.030(10)(a) and (b).
[48] According to RCW 19.285.030(14): "'Pacific Northwest' has the same meaning as the same term is defined in Section 3 of the Pacific Northwest Electric Power Planning and Conservation Act (94 Stat. 2698; 16 U.S.C. § 839a)", which in turn defines "Pacific Northwest" to mean: "the area consisting of the States of Oregon, Washington, and Idaho ...".

time, including PSE's 2009 IRP, PSE is anticipating acquiring wind energy resources at levels above those required by the RPS and is on that trajectory.

Current projections by PSE using the AURORA model indicate that in 2009 approximately 146 aMW of energy will be produced by existing wind resources, which represent 5 percent of total energy generation.[49] If the energy is generated as predicted by this model, PSE will reach generation levels in 2009 that are between the 2012 (3 percent) and 2016 (9 percent) RPS requirements.

Q. What do you conclude from this information?

A. The Company's acquisition of the Wild Horse expansion is justified in part by the need to comply with the RPS. The Company appears to be making substantial progress toward meeting that standard at the "compliance checks" in 2012 and 2016. This is important because wind projects have significant development timelines, and there are additional current and near-term constraints on development of these resources such as infrastructure for interconnection, and transmission limitations. Moreover, highly productive wind sites located in close proximity to existing transmission are becoming scarce. For all of these reasons, it is prudent to plan development substantially in advance of need to meet the RPS.

e. Conclusion on Wild Horse Expansion Prudence

Q. What is your conclusion regarding the prudence of PSE's acquisition of the Wild Horse expansion?

[49] PSE Response to Staff Data Request No. 23.

A. Based on the documents I reviewed, the analysis I conducted, and witnessing the wind turbine delivery and installation process, I conclude that the Company was prudent in acquiring the Wild Horse expansion.

4. Application of the Prudence Standard- Fredonia Units 3 and 4

Q. Do the same prudence standards you applied to Mint Farm and the Wild Horse expansion project apply to PSE's acquisition of Fredonia Units 3 and 4?

A. Yes. However, because Fredonia is neither baseload electric generation nor a renewable resource, those GHG and RPS statutory compliance issues need not be addressed in the prudence analysis.

a. The Need for the Resource; Evaluation of Alternatives; Cost

Q. Does the Company's direct testimony adequately support the need for Fredonia Units 3 and 4, and that it was the appropriate resource to acquire to meet that need?

A. Yes. The Fredonia gas turbines have been dedicated to serving PSE peak loads since 2001 under a lease agreement. Because the lessor gave PSE 60 days notice of its intent to terminate the lease in November 2008, PSE had to evaluate options to retain that existing capacity to serve peak loads at that time. As this resource was already part of PSE's generation portfolio, there was a clear need for this type of resource looking forward.

Q. How did PSE evaluate the options for acquiring Fredonia Units 3 and 4?

A. The Fredonia gas turbines are two-54 MW simple-cycle natural gas electricity generation CTs. PSE chose to exercise its purchase option for these CTs, which will occur at a favorable price at about January 2010. This decision involved evaluating three options to retain the Fredonia units, as well as the cost for acquiring the units. These CTs provide about 100 MW of peaking capacity and energy to the PSE system. They are also the newest PSE portfolio CTs with the lowest heat rate in the peaker fleet.[50] So, among the Company's peaker CTs, these units were relied upon to a large extent when peaking resources were needed. These units were also included in the assumptions made in the 2007 IRP and the 2008 RFP processes.

The three alternatives PSE examined were to: 1) negotiate an extension of the lease with the lessor; 2) purchase the plant from the lessor; and 3) contract to build or acquire a similar peaking resource from another party. The lessor was unwilling to negotiate a new lease. The option of acquiring a replacement plant would require more capital than the Fredonia plant and would not be available until 2012 at the earliest. That left purchasing the facilities as the remaining option.

Q. Was the price paid for the Fredonia units reasonable?

A. Yes. PSE's purchase option was attractive due to provisions in the lease agreement that allowed PSE to purchase the plant at a depreciated value. PSE ran a financial analysis, using the PSM, to verify that the purchase price was competitive, about half the purchase price of a similar new resource.[51]

[50] Garratt Exhibit No. RG-1HCT at 60-63.
[51] Elsea Exhibit Nos. WJE-1HCT at 46-48 and WJE-17C.

b. Participation of the Company's Board of Directors

Q. Did ~~PacifiCorp's~~ PSE's Board of Directors make the final decision to purchase the Fredonia units?

A. No. The decision was made by a team of PSE senior management called the Energy Management Committee ("EMC") on January 14, 2009 by examining the pertinent information summarized above.[52] Considering the analysis and information provided to the EMC and the need for immediate action on this unexpected lease termination, it was reasonable for PSE management to decide to purchase this longstanding peaking resource at an advantageous price without Board approval.

c. Documentation of the Company's Decision-Making Process

Q. Did PSE meet the documentation requirement for the acquisition of the Fredonia units?

A. Yes. PSE provided adequate contemporaneous records of its decision-making process and supporting analysis in this case, as cited above.

[52] Garratt Exhibit No.RG-29HC.

d. Conclusion on Fredonia Units Prudence

Q. What is your conclusion regarding the prudence of PSE's acquisition of the Fredonia units 3 and 4?

A. PSE satisfied all prudence factors and the decision to acquire the Fredonia generation units was made appropriately by PSE management. Therefore, I conclude that the Fredonia peaking units purchase was a reasonable and prudent choice for acquisition by PSE when that decision was made.

5. Application of the Prudence Standard- Power Purchase Agreements

Q. Do the prudence standards you applied to the resources above also apply to PSE's acquisition of the power purchase agreements?

A. Yes.

a. The Need for the Resource; Evaluation of Alternatives; Cost

Q. Does the Company's direct testimony adequately support the need for the PPAs and that they were the appropriate resources to acquire?

A. Yes. Because there are four separate PPAs subject to prudence evaluation is this case, I will describe each in turn.

Q. Please begin with the Barclays PPA.

A. The Barclays PPA is a 4 year, 3 month, winter around-the-clock power supply agreement for 75 MWh. It was executed in order to fulfill the higher winter peak season energy demand with a predictable price. The contract was executed through access to the FERC approved Western Systems Power Pool ("WSPP") Agreement and master confirmations between PSE and Barclays.[53] This energy will be provided from undetermined sources by Barclays around the clock during the heating season, November through February. This allows the Company to rely less on high cost peakers when all other generating resources are fully utilized and market prices are high. The final contract was negotiated to include a narrower time period than in the original offer (it excludes March), in order to fit the needs of PSE and to account for a diversity of risk among different counterparties and the Company's hedging strategy. This PPA was chosen as part of the 2008 RFP resources acquisition process.[54]

Q. Please continue with a discussion of the Puget Sound Hydro PPA.

A. The Puget Sound Hydro PPA is a 5 year, 1 month agreement for the total output of 1.5 MW power from Nooksack Falls hydroelectric plant. PSE had been contracted with Puget Sound Hydro for the full output of the Nooksack Falls hydroelectric power plant to provide energy to PSE's Glacier substation for some years. This PPA continues the relationship through a new contract for five more years to provide

[53] Garratt Exhibit Nos. RG-15, RG-16 and RG-17C.
[54] Elsea Exhibit No. WJE-1HCT at 31-33.

energy to the PSE grid. The high capacity factor, shape and reliability of this PPA have been proven to fit well with PSE energy needs.[55]

Q. Please continue with a discussion of the Qualco Energy PPA.

A. The Qualco Energy PPA is an agreement to purchase all power, 450 kilowatts, and a January 2009 agreement to purchase all renewable energy credits for five years, both from Qualco Energy, a biomass methane generator and energy production company located in Monroe, Washington. This small generating resource, less than 1 MW, is an addition to the renewable energy portfolio of PSE. It was offered to PSE outside the RFP process.[56] This PPA adds diversity to the renewable portfolio and provides the Company experience with this generating technology without significant risks.

Q. Finally, please discuss the Credit Suisse PPA.

A. The Credit Suisse PPA is an agreement for 50 MW of firm power delivered to Mid-C. It was executed in an expedited fashion when PSE needed an immediate replacement for the Lehman Bros. PPA when Lehman Bros. declared bankruptcy.[57]

[55] Elsea Exhibit No. WJE-1HCT at 41 and 42.
[56] Elsea Exhibit No. WJE-1HCT at 42.
[57] Garratt Exhibit Nos. RG-23, RG-24 and RG-25C.

Q. How did PSE evaluate the options for acquiring these four PPAs?

A. The acquisition of the Barclays PPA was the result of the 2008 RFP process described earlier in my testimony. All proposals and offers were evaluated using the same or similar modeling approaches and decision variables.[58]

The other PPAs were acquired outside of the RFP process, but using similar evaluation methods as next described. Puget Sound Hydro approached PSE regarding development of a new five year contract. PSE evaluated that offer using the PSM to assess how renewing the PPA would fit with other portfolio assets and its potential economic benefit compared to projected purchases.[59]

For projects like the Qualco PPA that are under 1 MW capacity, PSE does not use the PSM. Instead, PSE compares the pricing to be paid to Qualco under electric Schedule 91, Cogeneration and Small Power Production, to the forward pricing projections for equivalent purchases at Mid-C.[60]

The Credit Suisse PPA was evaluated against other market offers made immediately following the bankruptcy filing of Lehman Bros. This was performed using a live auction on September 16, 2008.[61]

Q. Were the prices paid for these PPAs reasonable?

A. Yes. The Barclays PPA was the top ranked PPA in Phase II of the 2008 RFP quantitative analysis process, which included price, and filled a need during the

[58] Elsea Exhibit No. WJE-1HCT at 24 and 25.
[59] Elsea Exhibit No. WJE-1HCT at 41.
[60] Elsea Exhibit No. WJE-1HCT at 42.
[61] Elsea Exhibit No. WJE-1HCT at 43.

winter peaking season. This PPA provided the [redacted] 20-year levelized cost in the final proposals list.[62] Final pricing was obtained through a bid process through the WSPP contracting process where four pre-qualified firms were asked to submit up-to-date bids for the desired contract terms.[63]

The Puget Sound Hydro PPA offered contract terms that were better than those available from the market at Mid-C over the period of the contract.[64]

Pricing for the Qualco Energy PPA was better than the cost of forward looking power purchases on the market, even including wheeling charges through Snohomish PUD.[65]

Finally, the Credit Suisse PPA was the winning bid at fixed rates lower than the other bidders, as well as below the cancelled Lehman Bros. contract pricing.[66]

b. Participation of the Company's Board of Directors

Q. Did ~~PacifiCorp's~~ PSE's Board of Directors make the final decision to purchase these PPAs?

A. Yes and no. The Barclays PPA was presented to the Board as part of the 2008 RFP evaluation process, as previously discussed. The decisions to acquire the remaining PPAs were made by PSE senior management.[67] However, considering the need for

[62] Garratt Exhibit No. RG-7HC at 102.
[63] Garratt Exhibit No. RG-14C at 2.
[64] Elsea Exhibit No. WJE-1HCT at 41 and 42.
[65] Elsea Exhibit No. WJE-1HCT at 42.
[66] Elsea Exhibit No. WJE-1HCT at 43.
[67] PSE Response to Staff Data Request No. 216.

immediate action in the case of the Lehman Bros. bankruptcy or in the other cases to continue existing power providers, and considering the relatively small amount of energy purchased and favorable price structures, it was reasonable for PSE management alone to decide to purchase these PPAs.

c. Documentation of the Company's Decision-Making Process

Q. Did PSE meet the documentation requirement for the acquisition of all four PPAs?

A. Yes. PSE provided adequate contemporaneous records of its decision-making process and supporting analysis in this case, as cited above.

d. Conclusions on PPA Acquisitions Prudence

Q. What is your conclusion regarding the prudence of PSE's acquisition of these PPAs?

A. PSE satisfied all prudence factors and the decisions to acquire the PPAs were made appropriately by either the PSE Board or senior management. Therefore, I conclude that the purchases of the PPAs were reasonable and prudent when those decisions were made.

C. Deferral Of Mint Farm Plant Costs

1. Baseload Electric Generation

Q. What is the significance of a Commission determination that a particular acquisition is "baseload electric generation" that must comply with the GHG emissions performance standard?

A. An acquisition must be "baseload electric generation" in order to qualify for automatic cost deferral so that expenses associated with the acquisition may be examined by the Commission for later recovery from ratepayers. As RCW 80.80.060(6) states: "An electrical company may account for and defer for later consideration by the commission costs incurred in connection with the long-term financial commitment, including operating and maintenance costs, depreciation, taxes, and cost of invested capital." A "long-term financial commitment" means baseload electric generation.[68]

Q. Did you previously address the other statutory elements that trigger the requirement for GHG emissions compliance?

A. Yes. I addressed them in my discussion of the prudence of the Mint Farm acquisition, though I referred the "baseload electric generation" issue to this section of my testimony.

[68] RCW 80.80.010(15).

Q. How is "baseload electric generation" defined in the GHG emissions statute?

A. "Baseload electric generation" is defined as "electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent." [69]

Q. What does "plant capacity factor" mean?

A. Plant capacity factor means "the ratio of the electricity produced during a given time period, measured in kilowatt-hours, to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatt-hours."[70] In other words, because there are 8,760 hours in a non-leap year, a plant operating at a capacity factor of at least 60 percent would operate at least 5,256 hours per year (0.60 * 8,760).

Q. Does the statute provide direction for evaluating whether a resource provides "baseload electric generation?"

A. Yes. According to the statute: "In determining whether a long-term financial commitment is for baseload electric generation, the Commission shall consider:

1. the design of the power plant; and
2. its intended use, based upon …
   i. permits necessary for the operation of the power plant and

[69] RCW 80.80.010(4).
[70] RCW 80.80.010(16).

ii. any other matter the commission determines is relevant under the circumstances.[71]

Q. What do you conclude from this list of factors?

A. I conclude that the statute places primary focus on the operational characteristics of the plant, i.e., the design and the permits, and any similar operating characteristic such as technical capability limitations or legal operating restrictions. The owner or operator's intent for operating the plant is relevant, but it is not the primary focus.

Q. What else supports your conclusion?

A. My conclusion is consistent with the rules both EFSEC and Ecology have adopted under the GHG emissions statute. These rules define what "designed and intended" means in the definition of the term "baseload electric generation" in RCW 80.80.010(4). According to these rules, "designed means originally specified by the design engineers for the power plant or generating units … installed at a power plant; and intended means allowed for by the current permits for the power plant, recognizing the capability of the installed equipment or intent of the owner or operator of the power plant."[72]

My conclusion is also supported by the context of the GHG emissions statute itself. It is apparent to me from the statute that any new fossil-fueled baseload electric generation sited in this state in the near term will be a gas-fired CCCT. This is because, although other fossil-fueled plants can meet the standard through use of

[71] RCW 80.80.060(3).
[72] WAC 173-407-110 (Ecology) and WAC 463-85-110 (EFSEC). These rules are worded the same, in part because these agencies were required to jointly develop these rules.

methods such as carbon sequestration, no such technology is yet available and proven on a large scale project. Furthermore, the Legislature's mandate that future emissions standards are to be based on combined-cycle combustion turbines for fossil-fueled baseload generation is reflected in the requirement that, every five years, the Washington Department of Commerce establish future GHG emissions requirements based on natural gas combined-cycle combustion turbine electric generation technology.[73]

At the same time, combined cycle combustion turbines are a flexible resource. Though they are designed with the technical capability to operate at a very high annualized capacity factor, up to about 85 percent, they often do not actually run at even a 60 percent capacity factor, because in practice, they are economically dispatched. And this percentage is anything but predictable as the price of gas and other factors vary dynamically. For example, in Phase II of PSE's 2008 RFP evaluation process, the Company modeled a CCCT to run at an estimated 28 percent annual capacity factor. As market prices for gas went down, by the time the Company created the Board presentation for the purchase of Mint Farm, the estimated annual capacity factor was up to 37 percent. Later still, in modeling runs for this general rate case, the Company's Aurora modeling estimated CCCTs to run at an annualized capacity factor of 46 percent. Finally, PSE ran Monte Carlo simulations of 1,800 yearly runs using its current trend modeling assumptions. The analysis projected an annual plant capacity factor for Mint Farm of over 60 percent in nearly half (45.7 percent) of all 1,800 test year runs.[74]

[73] RCW 80.80.050.
[74] Elsea Exhibit No. WJE-1HCT at 29.

While modeling of possible future annual plant capacities of a CCCT is an interesting exercise, it is highly variable and much less definitive than evaluating the permit conditions and actual technical capability of the plant as designed and installed. All of this suggests to me that the Legislature was primarily looking to the plant's technical capabilities and permit limits in establishing the definition of "baseload electric generation", and less on the actual intent of the owner or operator.

a. Design of the Mint Farm Plant

Q. Was Mint Farm plant designed to operate at an annual capacity factor of at least 60 percent?

A. Yes. The engineers who designed Mint Farm specified the equipment to be a baseload combined-cycle power plant. The turbine installed at Mint Farm is a '7F' series General Electric combustion turbine with a matched steam turbine. According to the manufacturer's specifications, this equipment has the capability to routinely meet and exceed a 60 percent annualized plant capacity factor.

The conclusion that Mint Farm meets the 60 percent annual capacity factor requirement is also supported by PSE's statements of over 90 percent plant availability factor (i.e., the percent of time the plant can operate, after accounting for outages).[75] Company witness Odom states that "Mint Farm and Sumas, and other combined-cycle plants…are designed to operate with Capacity Factors above 90

[75] Odom Exhibit No. LEO-1CT at 29.

percent" and "PSE intends to use the plants as baseload electric generation to the extent it is economical to dispatch the plants."[76]

The design of Mint Farm to operate at or above a 60 percent annual capacity factor is also reflected in the plant manufacturer's turbine operating and maintenance considerations document. That document characterizes an operating mode called "continuous service factor" as operations where the turbine operates at greater than 90 percent capacity.[77] Clearly, the manufacturer has designed this turbine with the capability of routinely operating at over a 90 percent capacity factor, far greater than the 60 percent capacity factor that would qualify as baseload electric generation.

Q. Has PSE, as the new owner, changed anything at Mint Farm that would materially affect the plant's capabilities?

A. No. In addition to retaining the same basic equipment configuration, PSE has retained the similar arrangements as the prior owner for plant maintenance and electric transmission.

b. Intended Use Based on Necessary Permits

Q. What does the relevant Mint Farm permit or other similar documents indicate regarding the issue of baseload electric generation?

A. Mint Farm must meet state and federal requirements for air quality. Ecology, in a letter dated December 17, 2008 from Sarah Rees, stated that Mint Farm "was

[76] *Id.*
[77] Odom Exhibit No. LEO-4 at 47.

designed, intended and permitted to operate as a baseload power plant."[78] In an interview with Ecology air quality engineer, Alan Newman, he stated to me that there are no restrictions on the maximum number of hours per year that Mint Farm can operate, which would otherwise restrict the ability of the plant to operate at a 60 percent annual capacity factor or greater. I also verified this 365 days per year operations allowance by reviewing Mint Farm's Southwest Clean Air Agency's Air Discharge Permit 04-2571R2.[79]

c. Intended Use Based on Other Relevant Factors

Q. Are there other factors you evaluated in considering whether Mint Farm qualifies as "baseload electric generation"?

A. Yes. PSE has sufficient firm gas supply and gas transportation arrangements to operate Mint Farm at or above a 60 percent annual capacity factor, and the Company has sufficient long-term electric transmission for Mint Farm through BPA. I base these conclusions on the testimony of Company witness Riding, my review of the actual contracts provided in response to data requests, and other relevant documents.

Q. What do you conclude from this evidence on the "design and intent" of Mint Farm?

A. Mint Farm is designed and permitted to operate at or above a 60 percent annualized plant capacity factor. I conclude that Mint Farm qualifies as "baseload electric

[78] Henderson Exhibit No. JMH-5.
[79] Henderson Exhibit No. JMH-3.

generation" for purposes of the GHG emissions statute. Therefore, PSE was permitted by statute to defer costs associated with that plant.

IV. CONCLUSION

Q. Please summarize your conclusions in this proceeding.

A. There is sufficient evidence to demonstrate that the Company was prudent in acquiring Mint Farm, the Wild Horse wind farm expansion, Fredonia Units 3 and 4, and the 4 PPAs discussed in this testimony. There is also sufficient support to conclude that Mint Farm and the Sumas CCCT meet GHG emissions performance standards. Finally, Mint Farm constitutes "baseload electric generation" that qualifies for automatic deferred accounting.

Q. Does this complete your direct testimony?

A. Yes.