EXHIBIT NO. LEO-13CT
DOCKET NOS. UE-090704/UG-090705
2009 PSE GENERAL RATE CASE
WITNESS: LOUIS E. ODOM

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-090704** **Docket No. UG-090705**

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF
LOUIS E. ODOM
ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED
VERSION

DECEMBER 17, 2009

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF LOUIS E. ODOM

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same Louis E. Odom who provided in this proceeding prefiled direct testimony, Exhibit No. LEO-1CT, on May 8, 2009, and prefiled supplemental direct testimony, Exhibit No. LEO-10CT, on September 28, 2009, each on behalf of Puget Sound Energy, Inc. ("PSE")?

A. Yes.

Q. What is the purpose of your prefiled rebuttal testimony?

A. My testimony responds to the recommendations by WUTC Staff ("Staff") and Public Counsel with respect to proposed changes in operations and maintenance ("O&M") costs included in the rate year for simple cycle combustion turbine ("SCCT"), combined cycle combustion turbine ("CCCT") and wind generation.

II. PRODUCTION OPERATION AND MAINTENANCE COSTS

Q. Have you reviewed the Staff and Public Counsel proposals regarding O&M costs for SCCTs, CCCTs and wind generation?

A. Yes, I have reviewed the testimony and the proposals included in the testimony. Staff proposes that the Company apply an accounting methodology it calls the "deferral method" for major maintenance events. Under this method, the actual cost of each planned major maintenance activity is capitalized and amortized to expense over an estimated period until the date of the next planned major maintance event. Additionally, Staff proposes the use of a historical five-year average of maintenance expense for power costs O&M for each facility rather than the use of an average calculated from the five-year forecast for maintenance at each of the company's combustion turbine facilities, as proposed in my prefiled direct testimony.

Q. Does PSE agree with Staff's proposal?

A. While I still believe PSE's original proposal is an appropriate methodology, Staff's proposal also appears to be acceptable, with the exception of Staff witness Kathryn Breda's method of calculating the normal maintenance expense, and on the condition that Ms. Breda's recommended amortization period for major maintenance be modified so that the correct time period between planned maintenance events is used for amortization. Therefore, the Company is agreeable to implement the accounting guidelines for maintenance in the manner similar to that recommended by Staff and Public Counsel. The Company further agrees to start amortizing the deferred amounts when the major maintenance is completed. Later in my testimony, I will present appropriate methodologies for calculating regular maintenance expense for both gas and wind turbines on a historical basis.

A. Major Maintenance

Q. Please explain how Staff's proposal differs from PSE's proposal for major maintenance.

A. As explained above, Staff proposes that the Company apply an accounting methodology it calls the "deferral method". Under this method, the actual cost of each planned major maintenance activity is capitalized and amortized to expense over an estimated period until the next planned major maintenance event. This methodology is similar to the accounting for planned major maintenance activities provided in the AICPA Guide for Airlines.

The Company's original proposed rate recovery for major maintenance was to adopt the "deferral method" for accounting used for overhauls within the airline industry. The methodology included deferring major maintenance costs that exceeded $2.0 million per occurrence and amortizing them over a five-year period. All costs under $2.0 million would be considered minor maintenance expense and would be calculated using an average of a five-year forecast.

Q. Why did the Company propose this accounting methodology?

A. The Company proposed the adoption of this methodology to conform to the recently implemented airline industry accounting guidelines and to establish defined threshold limits and fixed amortization periods to allow for ease of accounting and tracking. This proposal was reasonable and consistent with the accounting treatment under the accounting guidelines and the Accounting Standards Codification ("ASC") 980, previously SFAS 71.

Q. How does the Company propose rate recovery for major maintenance?

A. Consistent with Staff's and Public Council's recommendation, the Company is proposing implementation of the deferral method of accounting for planned major maintenance as set forth within the AICPA Guide for Airlines without the $2 million limit. The actual costs of each planned major maintenance activity will be capitalized and amortized to expense over the estimated period until the next planned major maintenance activity.

Q. How long are the periods between major maintenance activities for CCCTs and SCCTs?

A. GE has manufactured the majority of the Company's gas turbine generators ("GTG"), and GE's technical publication "Heavy-Duty Gas Turbine Operating and Maintenance Considerations" addresses the recommended maintenance period for PSE's GTGs. A CCCT's combustion components must be replaced and inspected on a regular basis, and GE has determined that the period between these major maintenance activities is normally between two to three years, depending on the number of starts and the amount of time the CCCT operates during the period.

A SCCT's combustion components must be replaced and inspected on a regular basis as well. However, due to a lower capacity factor, there is generally a longer period between the next similar scheduled maintenance activity. Please see the Third Exhibit to my Prefiled Direct Testimony, Exhibit No. LEO-4, for more information regarding maintenance schedules.

Q. Do the service agreements between the Company and GE require defined periods between major maintenance activities?

A. Yes. For example, pursuant to the service agreement at Mint Farm Generating Station ("Mint Farm"), the period between GTG combustion inspections is approximately every 8,000 to 12,000 factored fired hours. The period between GTG hot gas path inspections is approximately every 24,000 factored fired hours. The period between every GTG major inspection is approximately every 48,000 thousand factored fired hours. The service agreements for Goldendale, Sumas and Freddy 1 have similar contract provisions. Please see the following exhibits to my Prefiled Direct Testimony for specific service agreements: Exhibit No. LEO-6C, Exhibit No. LEO-7C, and Exhibit No. LEO-8C.

Q. Are there additional balance of plant ("BOP") equipment that will be affected by the proposed major maintenance accounting treatment at GTG facilities?

A. Yes. Major components such as heat recovery steam generators, selective catalytic reduction systems to meet exhaust emission limits, steam turbine generators, water treatment systems, large electrical apparatus and cooling towers will be affected by the proposed accounting treatment.

Q. What are the BOP equipment manufacturer's recommendations with respect to the maintenance period between activities?

A. Heat recovery steam generators, which include its selective catalytic reduction system, require an inspection and some amount of repair work every year. The steam turbine generator and other BOP equipment will have minor inspections every year, and major overhauls are called for on a five to ten-year cycle, depending on the equipment's operating profile, condition, and environment.

B. <u>Other Maintenance Expense</u>

Q. How does Staff determine production maintenance expenses for its proposed production O&M expense adjustments?

A. In general, Staff uses a historical five-year average of maintenance expense for gas generation plants rather than using the most current test year maintenance expense, which is a more accurate historical basis for maintenance expense.

Q. Is the Company agreeable to Staff's proposal to use historical maintenance expense to determine maintenance expense?

A. While I still believe that the Company's original proposal to use a five-year forecast of average maintenance costs for each facility is reasonable, the Company is willing to agree to use *recent* historical maintenance expense to determine maintenance expense. Additionally, as discussed in more detail below, for plants that PSE has recently acquired, it is appropriate to use historical maintenance expense from a similar plant.

Q. How does the Company propose to determine the maintenance expense of Goldendale Generating Station ("Goldendale")?

A. The Company would use the test year maintenance costs.

Q. Please explain why the most current test year expenses are a more accurate basis for determining proforma maintenance expenses for Goldendale than Staff's methodology.

A. Staff proposes to use an annualized thirty-month average (February 2007 through August 2009) of actual maintenance expense as a substitute for Goldendale's test year maintenance expense. Staff's proposed thirty-month average includes 2007 maintenance expense that was not representative of normal operations at Goldendale. In 2007, the facility was transitioning from operations under the previous owners and in July 2007 the facility experienced a major compressor failure that resulted in extensive capital repairs and the plant being out of service for ten weeks.

PSE proposes to use 2008 actual maintenance expense in the calculation of test year operations and maintenance cost, adjusted for major maintenance. PSE's methodology is superior to Staff's because, among other reasons, use of test year actual expense in those cases where test year information is available and representative of normal operations more accurately reflects the operating conditions for the turbines in relationship to the Company's portfolio of resources.

Q. Does PSE propose to use test year data for Mint Farm?

A. No, Mint Farm was not in-service during the test year, therefore, PSE proposed to use a similar turbine, which in this case is Goldendale.

Q. Please explain why Goldendale is a more accurate basis for determining proforma maintenance expenses for Mint Farm than Staff's methodology.

A. Staff proposed to use Mint Farm's annualized actual operations and maintenance expense over the eight-month period January 2009 through August 2009 and seven-month period February 2009 through August 2009 in lieu of test year data.

This method is inappropriate for several reasons. The January through August 2009 period excludes fall and early winter operations, and therefore is not representative of the operating profile experienced in a full twelve-month cycle. The period also does not reflect normal operations at Mint Farm. Mint Farm was acquired in late December 2008, and prior to May 2009, the facility was operated by General Electric International ("GE") using GE personnel under an Operations agreement negotiated by the previous owner. Throughout 2009, the plant was in the process of hiring personnel and was not fully staffed.

In order to provide representative Mint Farm data, the Company proposes to use test year data of a like facility (Goldendale), adjusted for known and measurable differences between the operations of the two facilities and adjusted for major maintenance as noted above. PSE's methodology takes into account representative maintenance expenses rather than simply disregarding large portions of data.

Q. What tine period would PSE use for determining maintenance on Sumas?

A. The Company proposes to use twelve months ended October 2009.

Q. Please explain why using a twelve month period ending October 2009 is a more accurate basis for determining proforma maintenance expenses for Sumas Generating Station ("Sumas") than Staff's methodology.

A. PSE acquired Sumas in July 2008, and Staff proposed to use an annualized actual operations and maintenance costs for the thirteen-month period of August 2008 through August 2009 to establish Sumas operations and maintenance expense. PSE believes this methodology to be inappropriate because the first full month of operations under PSE ownership was August 2008. August 2008 operations are not representative of normal operations because PSE was transitioning Sumas from its previous owners, and it was not yet fully staffed. The thirteen-month period used by Staff does not include a full thirteen months of representative expenses such as long-term contract costs.

The Company proposes to use actual operations and maintenance expenses for the twelve-month period ending October 2009 as a proxy for test year data, adjusted for major maintenance as noted above. This method more accurately reflects normal operations for Sumas.

Q. Do you believe the methodology used by the Staff for calculation of the representative year for the simple cycle plants Whitehorn, Fredonia, and Frederickson and the combined cycle plant Encogen is appropriate?

A. No. Use of test year operations and maintenance expense provides actual cost information that is more reflective of current operations and costs than a historical five-year average. Costs for labor, chemicals and material have increased steadily over the five-year period proposed by Staff. Use of a five-year average would deflate costs compared to the test year actual expense. Furthermore, operations and maintenance practices change and evolve over time, as does the maintenance requirements of aging generating and balance of plant equipment. Use of a five-year average "turns back the clock" and tends to disassociate cost recovery from current operations and maintenance practice. The Commission should reject Staff's proposed methodology.

Q. If the Commission determines that production maintenance should be based on historical maintenance expenses, what corrections need to be made to Staff's calculation of maintenance costs?

A. The following corrections to Staff's proposed maintenance expense, as presented on Ms. Breda's work paper work paper WP-KHB Adj 10.03 Power Costs (C) on tab "Maintenance on Thermals" and further adjusted for major maintenance as presented on the attached exhibit LEO-14C, would be necessary:

- <u>Encogen</u>: Replace $1,630,335 five-year average maintenance expense proposed by Staff with $1,184,664 actual 2008 maintenance expense; back out $48,984 of major maintenance expense incurred in 2008.
- <u>Frederickson</u>: Replace $538,169 five-year average maintenance expense proposed by Staff with $796,261 actual 2008 maintenance expense.
- <u>Fredonia Units 1-4</u>: Replace $1,239,681 five-year average maintenance expense proposed by Staff with $668,192 actual 2008 maintenance expense.
- <u>Whitehorn</u>: Replace $1,602,715 five-year average maintenance expense proposed by Staff with $4,839,332 actual 2008 maintenance expense; back out $4,585,047 of major maintenance expense incurred in 2008.
- <u>Freddy 1</u>: Replace $1,853,195 five-year average maintenance expense proposed by Staff with $1,983,996 actual 2008 maintenance expense; add adjustment in the amount of $256,294 to adjust Epcor 2010 and 2011 budgets to rate year.
- <u>Goldendale</u>: Replace $2,495,746 annualized maintenance expense proposed by Staff with $2,581,018 actual 2008 maintenance expense; back out $856,660 of major maintenance expense incurred in 2008; add $354,580 annual amortization expense associated with Combustion Inspection performed in May 2009..
- <u>Mint Farm</u>: Because there is insufficient historical cost data to provide a representative substitute period for the test year, PSE proposes using a similar facility's (Goldendale) test year actual O&M expense, adjusted for known and measurable differences, as a proxy for Mint Farm. Replace $4,997,350

annualized O&M expense proposed by Staff with $5,215,033 representing Goldendale test year O&M, excluding major maintenance and adjusted for known and measurable differences between Mint Farm operations and Goldendale.

- Sumas: Replace $3,495,336 O&M expense proposed by Staff with $3,594,194 O&M (actual O&M expense for the most recent twelve-month period, November 2008 through October 2009, less major maintenance of $70,076).

Q. What is the net effect of these corrections on gas generation production O&M costs?

A. The net effect is a reduction of $1.9 million in gas generation production O&M costs from Staff's proposal.

C. PSE's Management of Maintenance for Gas Generation Facilities

Q. Please explain the computer maintenance management system ("CMMS") program associated with the Company's gas generation facilities.

A. The current CMMS project is an add-on module to the Company's main business software SAP. This CMMS module is capable of tracking and providing information for technical asset management, maintenance planning and execution, preventive and predictive maintenance, reliability-centered maintenance, parts and services procurement, inventory management, employee and contractor management, asset accounting and maintenance budgeting, and asset performance analysis.

Q. How did the Company perform these asset management functions prior to the implementation of the SAP CMMS program?

A. Many of the recently acquired gas generation projects used some form of CMMS prior to being acquired by the Company. For example, both Goldendale and Sumas used the MAXIMO CMMS program under the previous owners. Under previous ownership, the Encogen Generating Station used the MAINSAVER CMMS program. PSE legacy plants have most recently used WINTERCRESS CMMS program.

Q. Why did the Company choose to switch from MAXIMO CMMS to the SAP CMMS?

A. The MAXIMO CMMS program would have required additional end user's license fees, whereas PSE already owned the software and user's licenses associated with the SAP CMMS program. Also, the SAP CMMS program is fully supported by PSE's main business software company. Further, it is possible to directly integrate SAP CMMS with the SAP business software platform, which the Company presently uses. This will enable better maintenance planning and scheduling by integration with existing SAP modules such as inventory management and materials procurement.

For the reasons stated above, PSE made the decision to switch from the other CMMS programs to SAP-CMMS.

D. PSE's Response To Proposals Regarding Generation Plant

A. Mint Farm

Q. How has Mint Farm been operating since PSE acquired the plant?

A. Mint Farm has operated very well since PSE brought the plant on-line in January 2009. Contrary to Public Counsel witness Scott Norwood's claim that Mint Farm does not appear to meet the baseload capacity factor standard of RCW 80.80.060, Mint Farm is designed and intended to run at an average capacity factor that exceeds the statutory baseload standard. As stated in the Prefiled Direct Testimony of David Mills, Exhibit No. DEM-1CT, Mint Farm is intended to run according to economic dispatch conditions, which means it will be operated as baseload generation except for times when equivalent power could be purchased at a lower cost in the market. As a matter of fact, for the period July 2009 through October 2009, Mint Farm's capacity factor has exceeded [redacted].

Q. What is the status of the facility upgrades to bring the plant up to Operating Standards?

A. All of the Mint Farm upgrades will be completed by the end of 2009 except for the Steam Turbine Control upgrades that will be completed concurrently with the normal spring outage of the plant. The total cost of the upgrades to bring Mint Farm up to Operating Standard is [redacted] million, nearly [redacted] million less than estimated for the May 2009 GRC filing.

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Q. Do you agree with Commission Staff that PSE "should be ordered to perform a flood potential hazard assessment to discover the current dike system that protects Mint Farm property"?

A. No. As Mr. Garratt discusses in his Prefiled Rebuttal Testimony, Exhibit No. RG-53HCT, Mint Farm due diligence identified that Mint Farm is located in the 500 year flood plain, and a 2007 U.S. Army Corps of Engineers document identifies that the levees in Dike District 1, the District where Mint Farm is located, are in good condition and well maintained.

Q. Do you agree with Staff's recommendation that PSE develop a flood contingency plan?

A. No. PSE management believes the current Emergency Preparedness and Fire Protection plan adequately address flood evacuation at the plant, given the minimal likelihood that a flood event will occur at Mint Farm. Please see PSE's Response to WUTC Staff Data Request No. 177, Exhibit No. LEO-15. Because Mint Farm is located in a 500-year flood plain and the levees are built on average three feet higher than the projected 500-year water level, there is no more than a 0.2% annual chance that there will be a flood event at the plant. Should a major flood event occur at Mint Farm, PSE's property insurance of the plant will cover the cost of flood damage over and above PSE's deductible.

B. Hopkins Ridge

Q. In her testimony on behalf of Staff, Ms. Breda proposes a reduction of $731,531 to the Company's request for O&M expense related to the Hopkins Ridge wind facility and Hopkins Ridge Infill project. Is this adjustment appropriate?

A. No. Ms. Breda proposes the removal of all forecast escalation from the Company's rate request related to the Hopkins Ridge service agreement with Vestas American Wind Technology ("Vestas") and a revised cost adjustment at the end of the current Vestas service agreement term – November 2010. This proposed adjustment removes known and measurable costs for this facility.

The Company prepares O&M budgets for every generating asset to maintain a high standard of personnel safety, appropriate equipment availability and reliability, robust environmental compliance and stewardship activities, and to optimize risk and ongoing equipment lifecycle expenditures. These budgets are carefully prepared in consideration of the foregoing objectives and actual operating experience, and the budgets account for both known and foreseeable costs plus the fees necessary to satisfy those objectives. Such a significant reduction to the Company's allowed recovery for O&M could negatively impact PSE's ability to meet its performance objectives. The Company disagrees that escalation costs specifically defined in a fully executed contract, plus pre-negotiated performance incentives and expected cost adjustments for the Vestas service agreement are not known and reasonably measurable. As proposed, Staff's recommendation is a cost reduction strategy that does not properly match revenues and expenses in the rate year for these machines.

Q. How is fee escalation determined in the Hopkins Ridge Vestas service agreement?

A. The year-over-year increase in the turbine maintenance fee is tied directly to the Consumer Price Index – Urban ("CPI-U") published by the U.S. Bureau of Labor Statistics ("Bureau"). As soon after the Bureau completes its seasonal rate adjustments and finalizes the annual rate, that percentage change is applied to the prior year's fixed contract amount to determine the fixed contract amount for the coming year.

Q. How has the CPI-U escalation rate changed since the Vestas service agreement was signed?

A. The Hopkins Ridge Vestas service agreement was signed March 7, 2005. Contract fee escalation has since increased as follows: 2006 CPI-U Escalation: 3.7%, 2007 CPI-U Escalation: 2.4%, 2008 CPI-U Escalation: 4.3%, 2009 CPI-U Escalation: 0.0%. Thus, the average annual escalation since wind turbine services began at Hopkins Ridge has been 2.6%.

Q. What escalation rate did the Company assume in preparing its 2009 rate request?

A. The CPI-U escalation rate for the Hopkins Ridge Vestas contract was assumed to be 3.0% each year in 2009, 2010, and 2011. The Hopkins Ridge O&M costs have been updated using the Company's standard Global Insight inflation forecast (1.6% in 2010 and 1.7% in 2011). This inflation forecast has also been used to pro form long-term O&M costs for the Wild Horse expansion.

Q. What accounts for the large increase in the cost of the Vestas Hopkins Ridge service agreement in December 2010 and beyond?

A. The original five-year term of the Vestas Hopkins Ridge service agreement ends in November 2010. As stated above, the Vestas service agreement was signed in March 2005 and provides a very advantageous fee structure that has not been seen since that time. After the end of the service term in November 2010, Vestas will provide no further warranty or turbine service. Service costs are rising due to a number of factors, including: the unique nature of wind turbine service requirements, its reliance on new technology, a generally young and developing workforce, major components sourced from third party or non-original equipment manufacturer suppliers, and the rapid pace of fleet utilization and maturity. Each successive negotiation with Vestas has resulted in increased fees for service and maintenance. As a result, the Company used its most recent fee negotiation for the Wild Horse expansion as a proxy for the service fees expected once the original Hopkins Ridge service term expires in 2010. That fee represented the best information available on wind turbine services pricing at the time, and [redacted] per turbine, per year, is used for the last four months of the rate year.

Q. Is that fee still reasonable given the current operating characteristics of these turbines?

A. Yes. The Company has been exploring a renewal of its service and maintenance agreement with Vestas to cover the post-term period. As the wind turbines continue to provide reliable energy, accumulate additional wear and tear, and exhibit the effects of aging, additional repairs and minor technology improvements will be required to optimize lifecycle cost. For maintenance services starting in 2010, the current Vestas service fee quotation is [redacted] per turbine per year. This is the most current available service pricing, and this fee has been used to update long-term facility O&M costs.

Q. The Company has explained why it disagrees with the proposed disallowance of escalation required in a contract and planned cost adjustments for the Vestas service agreement. Would you explain why the Company disagrees with the proposed disallowance of infrastructure maintenance and royalty costs?

A. Yes. The foregoing testimony rebutting Ms. Breda's proposed disallowance for the Hopkins Ridge Vestas contract applies equally to her proposal to disallow required escalation and planned increases in Vestas service fees related to the Hopkins Ridge Infill facility. These reductions are inappropriate for the same reasons stated earlier in my rebuttal testimony. However, the Company also disagrees with the proposed disallowance of foreseeable backfeed power costs, infrastructure maintenance costs, and landowner royalty payments. Each deserves additional comment.

Q. What is backfeed power, and why is it included in the Company's pro formed O&M budget for the Hopkins Ridge Infill wind facility?

A. Both the Hopkins Ridge wind facility and the Hopkins Ridge Infill project are connected to the Bonneville Power Administration ("BPA") transmission system. The turbines connect to the project substation via an underground electrical collection system and from the substation to BPA via an interconnecting power line. When the wind is blowing above nine miles per hour, the wind turbines generate electricity to serve their own operational needs and supply energy to the BPA system for transmission to the Company's system. On those occasions when the wind is blowing at less than nine miles per hour, the wind turbines automatically stand by and wait for wind conditions to improve. This standby condition maintains each wind turbine in readiness condition to immediately begin generating power. In this condition the turbine control system, step-up transformer, hydraulic system, lubrication system, and cooling system all consume a small amount of electrical energy. This consumptive load is sometimes called station service load or backfeed power, and is provided and metered by BPA and billed to the Company by the Columbia Rural Electric Association. Increasing the number of turbines at the facility results in an increase in need for backfeed power demand. This demand is a known and foreseeable consequence of adding turbines to the Hopkins Ridge Infill wind facility. Backfeed power costs are the subject of an electrical supply contract with the Columbia Rural Electric Association and are, thus, neither optional nor speculative.

Q. What is infrastructure maintenance cost, and why is it included in the Company's pro formed O&M budget for the Hopkins Ridge Infill wind facility?

A. In order to construct the Hopkins Ridge Infill wind project, additional roads, crane pads, turbine foundations, fiber optic communication lines, and underground electrical collection cables were built. Based on the experience gained from operating the Company's wind facilities and on prudent industry practice, routine infrastructure maintenance costs are a foreseeable expense and are included in the Company's rate request for the Hopkins Ridge Infill project. Failure to provide Vestas service access to the wind turbines in winter, to provide adequate storm water management in spring, to repair broken communication or electrical lines, to reduce project fire risk by spraying nearby weeds, or to inspect and maintain wind tower foundation bolts could all have deleterious consequences on the Company's safety, reliability, environmental and lifecycle risk objectives. The cost of infrastructure maintenance is a known and foreseeable consequence of adding turbines to the Hopkins Ridge Infill wind facility.

Q. Why were production royalty payments to landowners recommended for disallowance, and why are they included in the Company's pro formed O&M budget for the Hopkins Ridge Infill wind facility?

A. Staff proposes that all pro forma adjustments to the Company's rate request that involve a forecast, budget, or projection be removed. That apparently includes easily known and foreseeable contract and infrastructure costs, as discussed previously, but also appears to include contractual obligations such as production royalties. The Company does not own any of the real estate beneath the Hopkins Ridge Infill wind facility, but instead holds lease agreements with project landowners. Through these leases, landowners grant PSE permission to construct and operate wind turbines on their land. In exchange for that permission, the landowners are compensated with a stipulated royalty payment tied to the actual production of electrical energy on their land. This royalty is a requirement of the lease agreement and does not represent an optional project expenditure. If seasonal and annual energy production from the wind facilities are appropriately forecast in resource portfolio models, then pro formed royalties tied to the same energy forecast are appropriate in determining production O&M cost. Under Ms. Breda's approach to implementing pro forma adjustments, the full benefits of the low cost power are used in setting power costs yet the associated costs of operating the plant are not. This is clearly a mismatch of revenues and costs.

III. WILD HORSE PRODUCTION O&M

Q. In her testimony, Ms. Breda proposes a $434,980 reduction of the Company's request for O&M expense related to the Wild Horse wind facility. On what basis is this reduction proposed?

A. Ms. Breda proposes the removal of all forecast escalation from the Company's rate request related to the Wild Horse service agreement with Vestas.

Q. Is the proposed reduction a reasonable adjustment?

A. No. At stated with respect to Ms. Breda's proposed Hopkins Ridge and Hopkins Ridge Infill disallowance, the Company prepares O&M budgets for every generating asset to maintain a high standard of personnel safety, appropriate equipment availability and reliability, robust environmental compliance and stewardship activities, and to optimize ongoing risk of equipment lifecycle expenditures. These budgets are carefully prepared around the foregoing objectives and actual operating experience; they account for both known and foreseeable costs and fees necessary to satisfy those objectives. The Company disagrees that escalation specifically defined in a contract and expected cost adjustments for the Vestas service agreement are not known and measurable.

Q. How is fee escalation determined in the Vestas service agreement?

A. The year-over-year increase in the turbine maintenance fee is tied directly to the Gross Domestic Product Implicit Price Deflator ("GDPIPD") published by the

U.S. Bureau of Economic Analysis ("Bureau"). Soon after the Bureau completes its seasonal rate adjustments and finalizes the annual rate, that percentage change is applied to the prior year's fixed contract amount to determine the fixed contract amount for the coming year.

Q. How has the GDPIPD escalation rate changed since the Vestas service agreement was signed?

A. The Wild Horse Vestas service agreement was signed September 30, 2005. Contract fee escalation has since increased as follows: 2007 GDPIPD Escalation: 0.0% (per contract), 2008 GDPIPD Escalation: 3.2%, 2009 GDPIPD Escalation: 2.7%, 2010 GDPIPD Escalation: 0.6%. Thus, the average annual escalation since wind turbine services began at Wild Horse has been 2.95%.

Q. What escalation rate did the Company assume when preparing its 2009 rate request?

A. The GDPIPD escalation rate for the Wild Horse Vestas contract was assumed to be 3.0% each year in 2009, 2010, and 2011. The Wild Horse O&M costs have been updated using the Company's standard Global Insight inflation forecast (1.6% in 2010 and 1.7% in 2011). This inflation forecast has also been used to pro form long-term O&M costs for the Wild Horse expansion.

Q. Will there be a large planned increase in the Vestas Wild Horse service fee during the rate year?

A. No. The original five-year term of the Vestas Wild Horse service agreement ends in December 2011, beyond the end of the rate year.

Q. If the Commission were to provide rate recovery on the basis of these forecasts, budgets and pro formed expenditures, what assurance can the Company provide that these are true and correct costs?

A. As stated earlier in my rebuttal testimony, production O&M for the wind projects is determined on the basis of safety, reliability, environmental, and lifecycle risk objectives. The only costs forecast, budgeted, or pro formed for the facilities are those that are known and/or foreseeable, and necessary to the successful operation of the project. Comparing the forecast rate request from PSE's most recent power cost only rate case, Docket No. UE-070565, with actual O&M costs from the rate year period for Wild Horse provides a credible assessment of the Company's success at budgeting wind facility O&M and executing on its plan. By way of example, in 2007 the Commission granted the Company [redacted] in production O&M to operate and maintain the Wild Horse wind facility for the rate year September 2008 to August 2009. Actual expenditures during the same period were [redacted]. Thus, expenditures for the Wild Horse project were within 1.8% of the cost recovery requested.

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IV. WILD HORSE EXPANSION PRODUCTION O&M

Q. In her testimony, Ms. Breda proposes adjustment of the Company's request for O&M expense related to the Wild Horse expansion wind facility by $709,625. On what basis is this reduction proposed?

A. Ms. Breda proposes to remove all forecast escalation from the Company's rate request related to the Wild Horse expansion service agreement with Vestas, additional project management staff, and all other requested and foreseeable costs related to operations and maintenance of the infrastructure, including project development royalties.

Q. Is the proposed reduction a reasonable adjustment?

A. No. As stated above with respect to her proposed adjustment of Wild Horse Vestas service agreement fees, the Company prepares O&M budgets for every generating asset that supports the operating standards discussed earlier.

Q. Does the Company have any further objections with the proposed disallowance of infrastructure maintenance and royalty costs?

A. Yes. The Company disagrees with Ms. Breda's proposed disallowance of the additional management staff, foreseeable infrastructure maintenance costs, and project development royalty payments. The Company's concerns regarding the disallowance of infrastructure maintenance costs and royalties have been stated previously in this testimony and will not be repeated here. However, some additional comments apply to the proposed disallowance of Wild Horse expansion project expenses.

Q. Why is additional management staffing included in the Company's pro formed O&M budget for the Wild Horse expansion?

A. Unlike the central location at the Hopkins Ridge wind facility, the location of the Wild Horse operations and maintenance building is near the southern boundary of the facility. Since the expansion site was located beyond the northern boundary of the original Wild Horse wind facility, drive times from the O&M building are routinely 30-45 minutes to the first expansion turbine. The combination of longer drive times, additional infrastructure for 22 new turbines, additional need for environmental monitoring of this new area, additional oversight of a larger Vestas maintenance crew, and increased site security needs does require additional workload greater than could be absorbed by the existing staff. One new team member, a Project Coordinator, has been added to manage the increased workload. The Project Coordinator is responsible for coordination of logistics and resources, provides inspection and oversight in support of the Plant Manager, manages the field relationship between Vestas and other service providers and the Company's internal departments, and reports on the status of maintenance or improvement projects. This one additional staff member has helped the Wild Horse team to realign workloads and improve their facility management effectiveness.

Q. What is infrastructure maintenance cost and why is it included in the Company's pro formed O&M budget for the Hopkins Ridge Infill wind facility?

A. In order to construct the Wild Horse expansion wind project, additional roads, crane pads, turbine foundations, fiber optic communication lines, and underground electrical collection cables were built. In addition, a new bay has been added in the existing substation complete with new switchgear, relaying, and main step-up transformer. Based on the experience gained from operating the Company's wind facilities and on prudent industry practice, routine infrastructure maintenance costs are certainly a foreseeable expense and are included in the Company's rate request for the expansion project. The cost of infrastructure maintenance is a known and foreseeable consequence of adding turbines to the Wild Horse expansion wind facility.

Q. Why were development royalty payments recommended for disallowance, and why is it included in the Company's pro formed O&M budget for the Wild Horse expansion wind facility?

A. Ms. Breda proposes that all pro forma adjustments to the Company's rate request that involve a forecast, budget, or projection be removed. While the Company owns the real estate beneath the Wild Horse expansion wind facility, it holds ongoing payment obligations with the original project developers. In the development rights transaction that brought Wild Horse to the Company, the project developers retained a stipulated royalty payment provision tied to the actual production of electrical energy from the facility. This royalty is a requirement of the development agreement and does not represent an optional project expenditure. It is known and measurable as the generation used in setting power costs.

Q. Ms. Breda uses PSE's Response to Staff Data Request No. 143(b) to support her statement that PSE is not consistent in its use of forecasts for power costs, and "actual results can vary considerably from a forecast (italics added)". Does the Company agree?

A. No. Ms. Breda does not provide PSE's full response. The response stated that the differences were caused by an error in the escalation factors. The error was only $72 thousand for 2010 and $56 thousand in 2013/2014, but Ms. Breda implies that PSE knowingly used different assumptions. The simple mathematical error in the Company's spreadsheets caused only minor differences, which PSE stated it would update upon rebuttal if the spreadsheets were to be used.

V. CONCLUSION

Q. Does that conclude your prefiled rebuttal testimony?

A. Yes.