EXHIBIT NO. ___(RG-47HC)
DOCKET NO. UE-07___/UG-07___
2007 PSE GENERAL RATE CASE
WITNESS: ROGER GARRATT

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-07____** **Docket No. UG-07____**

FORTY-SIXTH EXHIBIT (HIGHLY CONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF ROGER GARRATT ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

DECEMBER 3, 2007

GE – GOLDENDALE TURBINE ROTOR REPAIR OPTIONS AUGUST 2007

The individuals below participated in the review and analysis of the GE Goldendale Turbine Rotor Repair Options. Based on the contributions of our respective department's and best information available, we support the findings presented in this document.

Title	Signature	Date
Director Cost & Regulation – John Story		
Manager, Energy Analysis – Kacee Chandler		
Energy Resource Planning Acquisition Financial Analyst – Cara Gudger		
Director Structuring Asset Optimization & Analytics – Salman Aladin		
Director Wind and Thermal Assets – Ed Odom		
Insurance Administrator – Tom Barnhart		
Manager Property Accounting – Bruce Bollert		
Manager Thermal Assets – Charles Morton		

Approved, VP Power Generation
Paul Wiegand

Date

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Goldendale Turbine Rotor Repair – Feasibility Report

1.0 Executive Summary

On July 24, 2007 the Goldendale Generating Station combustion turbine generator (CTG) failed in service with indications of problems with its compressor. An initial visual inspection of the compressor was performed with a boroscope and Foreign Object Damage ("FOD") within the unit's compressor and turbine sections was seen. GE, as the CTG's manufacturer, assisted with the initial investigation and was able to mobilize personnel to disassemble the unit and provide preliminary estimates on the range of costs and schedules that might be required to return the plant to service.

GE submitted six preliminary repair options on July 31, 2007 before the compressor casings and turbine shell were removed and the full extent of damage was visible. The preliminary cost estimates for these options ranged from approximately $10 to $34 million with schedule durations of 26 to 5 weeks, respectively. Acceptance of any of these options required PSE to agree to a Letter of Intent (LOI). This LOI was based on PSE reaching a long term maintenance agreement with GE known as a Contractual Services Agreement (CSA) for the Goldendale CTG. The LOI requires that the CSA be executed by November 1, 2007. Negotiations with GE on a CSA were in progress prior to the unit failure.

The unit's rotor was fully exposed and GE submitted revised repair options on August 7, 2007. GE's new proposal narrowed the scope of work to two options for compressor work and one option for the turbine section of the CTG.

An initial effort was made by the PSE staff to evaluate the original six preliminary options. With the receipt of the two revised options dated 8/7/07, the final analysis was revised to focus on the two new options. The analysis considered replacement power costs and impacts within the Power Cost Adjustment (PCA) mechanism, as well as impacts to transmission and winter peaking capacity, plant accounting, taxes, rates and insurance recovery risk.

The repair option that provides the least financial risk to our customers and provides the best cost benefit to afford PSE a prompt repair has been determined to be Option 2 of the turbine repair options contained in GE's proposal dated August 7, 2007, as updated August 14, 2007. This is the preferred option because it provides the least financial impact to the customers and returns the plant to service in the shortest amount of time.

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2.0 Repair Options Considered

2.1 GE – Original 6 Preliminary Repair Options

GE was requested to provide preliminary repair options prior to exposing the full rotor so that PSE could consider the order of magnitude of the cost and outage schedule impacts. More accurate options were mutually established and submitted by GE on August 7, 2007. For evaluation purposes, details of the preliminary Option #6 are provided since it establishes a "worst case" estimate of the time needed to return the plant to service.

Option #6: This option has an 18 to 26 week repair time at a cost of $9.6 million. The compressor rotor will be rebuilt and HGP components repaired where necessary. An LOI to enter into a CSA is required.

2.2 Third Party Repair Options

Calpine & Dominion were approached to provide an estimate for repairs, but were unable to locate a compressor rotor to be installed on the turbine shaft. They checked with other user group members and none of them had a compressor rotor available which would work in a GE-7FA. Without a compressor rotor, this option is not achievable.

A third party market for turbine parts for the GE-7FA is essentially non-existent. The only source of parts other than GE is through direct purchases from other GE-7FA owners (purchase parts that an owner has in inventory). The companies approached were unable to track down the parts needed to repair the Goldendale GE-7FA.

2.3 GE Proposal August 7, 2007

Option 1: This option estimates a 9 to 10 week repair time from receipt of rotor in Houston at a cost of $7.069 million. The existing compressor rotor will be un-stacked and rebuilt. An LOI to enter into a CSA is required.

Option 2: This option estimates a 6 to 7 week repair time from receipt of rotor in Houston at a cost of $8.440 million. The existing compressor rotor will be exchanged for a refurbished rotor. The refurbished rotor will have a known operating history and all known technical issues with it will have been addressed. An LOI to enter into a CSA is required.

Turbine Rotor and Hot Gas Path (HGP) Component Rebuild: This option has a 3 week repair time that runs simultaneously with the above options at a cost of $8.588 million.

2.4 GE Proposal August 14, 2007

Refurbished Compressor Rotor and Refurbished HGP parts: This proposal combines Option 2 and the Turbine Rotor Option of the August 7, 2007 proposal and estimates a 7 week repair time at a cost of $18.002 million. This cost has the additional cost of the 1st stage shroud replacement and repairs to the 2nd stage shroud.

3.0 Economic Justification / Analysis

3.1 Economics

The following economic analysis considers the incremental impact to PSE and its customers as a result of the Goldendale turbine rotor repair for Options 1 and 2. It incorporates increases in replacement power cost, accounting and tax treatment of the retirement and subsequent plant additions, adjustments made to the forecast major maintenance schedule, insurance recoveries, and the resulting impacts to net income for the current year and the remaining book life of the plant. The full Economic Analysis is attached.

It is important to note that option 1 requires a complete teardown of the compressor rotor exposing the possibility of additional, unforeseen, repair work. In option 2 the exchanged refurbished compressor rotor has been completely rebuilt, removing any risk of additional costs and outage time.

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Goldendale Turbine Rotor Repair – Feasibility Report

Summary:

Goldendale Rotor Replacement Cost Analysis August 16, 2007		
All dollars in $MM	Option 1 + Turbine	Option 2 + Turbine
Outage Duration in Weeks Starting 7/30/07	13	10
GE Capital Cost	$15.70	$18.00
GE O&M	1.00	-
PSE O&M	0.50	0.50
Total Rotor Replacement Cost	$17.20	$18.50
2007 Net Income (Loss) without Power Cost	($0.59)	($0.22)
2007 Power Cost Increase (pre-tax)		
Expected Lost Generation Revenue: -1 SD	$8.11	$6.55
Expected Replacement Power Costs: Mean	6.09	5.20
Expected Lost Generation Revenue: +1 SD	3.81	3.81
2007 Net Income (Loss) with Power Cost (post-tax)*		
2007 Net Income Impacts: -1 SD	($5.87)	($4.48)
2007 Net Income Impacts: Mean	(4.55)	(3.60)
2007 Net Income Impacts:+1 SD	(3.07)	(2.70)
NPV Net Income (Loss) with Power Cost**		
NPV of Incremental Difference - 1 SD	($8.64)	($8.06)
NPV of Incremental Difference: Mean	(7.39)	(7.18)
NPV of Incremental Difference + 1 SD	(5.84)	(6.28)

* Power Cost is tax adjusted at FIT rate of 35%
**Analysis assumes an NPV of 28 years, discounted at 8.4%

The summary above illustrates that Option 2 provides the lesser impact in incremental cost with a 2007 net loss of $3.60 million, while Option 1 provides a 2007 net loss of $4.55 million. The impacts of replacement power cost, adjustments in depreciation, interest expense and accounting treatment of the unit of property retirement more than make up for the $1.3 million total cost difference from Option 1. Option 2 is also $0.15 million less than Option 1 on a Net Present Value basis which considers the forecast costs of the repair over the 28 year remaining life of the plant.

The following are the major assumptions used in the analysis:

- The Goldendale Turbine Rotor Repair is considered a major maintenance item and therefore, the event resets Goldendale's forecast major maintenance schedule. The incremental difference in capital and operation and maintenance (O&M) expenditures is reflected in the analysis.

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- The assets to be retired are determined by the parts PSE purchases in the different options. If the parts are rebuilt, as some will be in Option 1, those parts will not be retired. If the parts are refurbished, the associated unit of property value will be retired and the parts PSE receives from GE will be added to the plant book and tax values. Option 1 assumed approximately 1 percent of the total rotor gross plant value to be rebuilt.

- The insurance payment is considered as salvage value and offsets the O&M expenditures and capital retirement adjustments ratably. [redacted]urance recovery range noted below and a $1 million deductible, the analysis assumed a [redacted]nsurance recovery.

- PSE will propose an update to the Goldendale plant depreciation rate in the upcoming General Rate Case. New depreciation rates are estimated to be effective November 1, 2008 and will reflect the GE repair capital costs, the plant retirement and insurance recoveries.

- The asset retirement will create a deferred tax liability that will reverse over the remaining life of the plant.

3.2 Accounting Treatment (Capital versus Expense):

3.2.1 Replaced Units of Property:

As required by the FERC Uniform System of Accounts, any replacements of defined "Units of Property" would be capitalized, along with the costs to install. The costs of the replaced unit would be retired, including the cost of removal. The replacement of any units not defined as "Units of Property" would be expensed.

The gross book value of the units of property included in PSE's plant accounts for the rotor at issue is estimated to be $58,866,778. For purposes of the analysis, the rotor was determined to all be units of property. Option 1 + turbine replacement capital is estimated to be $15.7 million and Option 2 + turbine replacement capital is estimated to be $18.0 million.

Any credit for scrap value given to PSE by the manufacturer on the purchase of new parts should be accounted for as salvage in account 108-Accumulated Depreciation. The new parts should be recorded at the gross amount before the credit.

3.2.2 Refurbished Units of Property:

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Per WAC 480-07-160

For units of property that are removed, refurbished and reinstalled, FERC requires the cost of transportation and refurbishment be expensed. Cost to remove and reinstall the units, however, is capitalized according to FERC.

3.2.3 Depreciation & Insurance Proceeds:

PSE uses the half year convention for additions and retirements. Therefore, a half year of depreciation should be taken on capital additions or retirements in the year of the transaction, which is 2007 for this analysis.

The insurance proceeds should be allocated between capital retirements and expense reimbursements based on an appropriate method. The amount allocated to retirements will be accounted for as (credited to) salvage in accumulated depreciation.

3.3 Replacement Power Cost and PCA Impact:

The Portfolio Analytics team determined the expected loss and variability of power costs for each option. The PCA impact was also calculated for all options. Note the PCA total imbalance in 2007 was expected to be at $16.6 million per the 6&6 Outlook which reflected $5.6 million of replacement power costs and an estimated Goldendale outage of 10 weeks. It is important to note that the "Weeks to Repair" were evaluated from July 30, 2007 when PSE was provided with GE's original proposal. Options 1 and 2 from the August 7, 2007 proposal have time frames initiating on the arrival of the turbine.

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3.4 Transmission and Winter Peaking Capacity

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Power Supply Operations noted that the Goldendale generation station transmission could be redirected during the plant outage period. Given the illiquid market conditions for secondary transmission, however, it was determined that no financial benefit related to this transmission could be realized over any of the options' timeframes. In addition, the Portfolio Analytics team analyzed the impact to the winter peaking planning which indicates only a small $100,000 power costs increase during the November 2007 to January 2008 period, which would occur only if the Goldendale outage lasts more than 14 weeks.

3.5 Insurance Treatment

The insurance company claims adjuster visited the site on 8/3/07 to view the damage to the combustion turbine unit. At the time, the cover of the unit had been removed, and the top half of the rotor was exposed. Based on the exposed sections of the rotor, the adjuster estimated the cost to repair the damage resulting from the insured event to be between [redacted] The adjuster plans to view the entire rotor when it arrives at the GE shop in Houston, estimated to be August 13, 2007. At that time, he can provide a more accurate estimate. In addition to on-site GE crew costs for removing and re-installing the rotor and the shop repair costs, reasonable expediting costs (such as overtime and priority transport) are an expense covered under PSE's insurance policy, subject to a $3M sublimit. The total insured loss is subject to a $1 million policy deductible.

4.0 Findings and Recommendations

4.1 Selection of Preferred Option

Option 2 combined with the Turbine Rebuilt Option detailed in GE's August 7, 2007 proposal and updated cost estimates received August 10, 2007 and August 14, 2007 provide the most technically and financially acceptable solution based on the most current information on the unit's condition, repair cost estimates, incremental financial impacts and replacement power costs. The time estimate of approximately ten weeks provides the shortest possible plant outage period and therefore minimizes the financial risk of acquiring replacement power in the market. Additionally, this option provides the least impact to net income for the current year and to the net present value of all future costs associated with the outage.

5.0 Schedule

PSE will prepare a detailed work scope, cost estimate and schedule for tracking this project. The milestone dates are:

- Unit Failure July 24
- GE mobilized on site July 30
- Rotor removed from plant August 7
- Rotor due to GE's Houston Texas shop August 14

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- Estimated plant return to service based on GE authorization to proceed no later than August 13 is September 24

6.0 Estimated Cost

As noted in above section three, the financial analysis considered the estimated cost to implement Option 2 to be $18.0 million capital plus $0.5 million O&M expense, for a total of $18.5 million. Costs increased $0.9 million due to the addition of the 1st and 2nd stage shroud work that has been identified as needed repairs; this work would have been done under either of the options in the August 7, 2007 proposal.

7.0 Attachments

A – GE Original Estimate with 6 Options

B – GE Compressor and Turbine Repair Proposal dated 08/07/2007.

C – GE Compressor and Turbine Repair Proposal dated 08/14/2007.

D – GE LOI to pursue CSA

E – Economic Analysis