**EXHIBIT NO. ___(KRK-1T)**
**DOCKET NO. UE-06___/UG-06___**
**2006 PSE GENERAL RATE CASE**
**WITNESS: KARL R. KARZMAR**

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY, INC.,**<br><br>**Respondent.** | **Docket No. UE-06____**<br>**Docket No. UG-06____** |

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**
**KARL R. KARZMAR**
**ON BEHALF OF PUGET SOUND ENERGY, INC.**

**FEBRUARY 15, 2006**

**PUGET SOUND ENERGY, INC.**

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF KARL R. KARZMAR**

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**PUGET SOUND ENERGY, INC.**

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF KARL R. KARZMAR**

## I. INTRODUCTION

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

A. My name is Karl R. Karzmar. I am the Director of Regulatory Relations at Puget Sound Energy. My business address is 10885 N.E. Fourth Street, Bellevue, Washington, 98009.

**Q. Would you please provide a brief description of your educational and business experience?**

A. Please see Exhibit No. ___(KRK-2).

**Q. What topics are you covering in your testimony?**

A. With respect to gas results of operations, I present the calculation of the adjusted test period, ratebase, working capital, conversion factor and the overall revenue requirement. I will explain the various adjustments to the results of operations for the current test year and, after taking into account these adjustments, present the adjusted test period and the resultant revenue requirement. I also describe the allocation of common expenditures between electric and natural gas.

Based upon the adjusted test period revenues of $960,901,702 for sales to customers, the requested gas general rate case revenue deficiency in this case is $40,439,958, which represents an average 4.21% increase.

In addition to this general revenue deficiency, there is an additional revenue requirement associated with the Company's proposed Depreciation Tracker mechanism of $10,884,680, or 1.13%, over current revenues. Mr. John Story discusses the Depreciation Tracker mechanism in his testimony, Exhibit No. ___(JHS-1T). When combined with the gas general revenue deficiency, the total requested gas revenue increase in this case is $51,324,638, or an average 5.34% for gas service customers.

I will also discuss a proposed change to the Company's Purchased Gas Adjustment ("PGA") mechanism related to credit costs associated with the Company's gas portfolio hedging activities. Finally, my testimony discusses the Company's proposals to address regulatory lag and attrition as they related to gas customers.

## II. TEST YEAR FINANCIAL STATEMENTS AND RATEBASE

**Q. Would you please explain Exhibit No. ___(KRK-3)?**

A. Exhibit No. ____(KRK-3) presents the actual financial statements for the test year before any pro-forma or restating adjustments. Page 3.01 of this exhibit presents a comparison between the gas income statement for 9/30/2003, the test year for the last general rate case in Docket No. UG-040640 et al. (the "2004 general rate case"), and the gas income statement for 9/30/2005, the test year for this general rate case filing. Page 3.02 of the exhibit presents the gas balance sheet for the same time periods and page 3.03 of the exhibit presents the ratebase calculation for the current test year prior to any pro forma and restating adjustments. Mr. Story presents the equivalent schedules for electric operations in his Exhibit No. ___(JHS-3).

**Q. Is the ratebase calculation done in the same manner as allowed in the last general rate case?**

A. Yes, with two exceptions. The first difference is that the deferred tax accounts that were related to indirect overheads have been removed from ratebase consistent with the accounting treatment provided for in the Company's accounting petition in Dockets UE-051527 and UG-051528 approved by the Commission on October 26, 2005, and consistent with similar treatment for electric ratebase in this case. In his testimony, Mr. Story explains the reasons for this change.

Consistent with the Commission's order in the above dockets, these tax balances have been removed from ratebase and are treated as operating investment in the working capital calculation, shown on page 4 of this Exhibit, for this test period. As Mr. Story explains, the Company was allowed to defer the carrying cost associated with the payment of these taxes during the last quarter of 2005 and during 2006. I will discuss the Company's proposed amortization schedule for these deferred costs later in my testimony.

The second change in the calculation of ratebase is that deferred tax balances on the balance sheet are treated in compliance with a memo from Mr. Matthew Marcelia, PSE's Director Tax. Mr. Story has provided a copy of the memo as his Exhibit No. ___(JHS-13C).

The calculation of the test year ratebase with these two adjustments but before restating and proforma adjustments is shown on page 3 of Exhibit No. ___(KRK-3).

**Q. Would you please explain the working capital calculation?**

A. The purpose of this calculation is to provide a return on the funds the shareholders have invested in the Company for utility purposes that have not been invested in plant or other specifically identified ratebase items already earning a rate of return. The calculation is based on the average of the monthly averages of the actual amounts in the asset and liability accounts for the test year.

The first part of this adjustment calculates the total average invested capital that has been utilized during the test year. From the average invested capital, the operating investment which is earning a return, or is excluded from earning a return, is deducted. A second deduction is made for non-operating assets and plant not in service. The result is total working capital provided by the shareholder.

This total investor supplied working capital is then allocated between non-operating working capital and operating working capital using the method consistent with previous rate cases which is the ratio of operating or non-operating investment to the total operating and non-operating investment. The resulting operating working capital represents the shareholder's average investment which is required to provide utility service but which would otherwise not earn a return. The gas working capital calculation is shown in Exhibit No. ___(KRK-3), page 3.04.

**Q. Please explain the final page of Exhibit No. ___(KRK-3).**

A. The final page of this Exhibit presents the Allocation Methods, or factors, used in allocating common expenditures between electric and natural gas.

Common Utility Plant is that portion of utility operating plant that is used for providing more than one commodity, i.e., both electricity and gas, to customers. Common plant includes costs associated with land, structures, and equipment which are not charged specifically to electric or gas operations because the assets are used jointly in providing service to both commodities. The Company allocates its common utility plant in determining ratebase by using the four-factor allocation method as authorized in the stipulation approving the merger of Puget Sound Power & Light Company and Washington Natural Gas Company. Components of the four-factor allocator include the number of customers, direct labor charged to O & M, Transmission and Distribution O & M, and net classified plant (excluding general plant).

Common operating costs are those costs that are incurred on behalf of both electricity and gas customers. The Company incurs common costs related to: Customer Accounts Expenses; Customer Service Expenses; Administrative and General Expense; Depreciation/Amortization; Taxes Other Than Federal Income Tax and Current and Deferred Income Taxes. The most appropriate allocation method based on type of cost is applied to each type of common cost. Allocation methods used include: (1) twelve month customer average; (2) joint meter reading customers; (3) non-production plant; (4) four factor allocator; (5) direct labor; (6) current tax and (7) deferred tax.

## III. GAS PRO FORMA AND RESTATING ADJUSTMENTS

**Q. Please explain your Exhibit No. ___(KRK-4).**

A. The first page of this exhibit, Summary page, presents the unadjusted operating income statement and Average-of-the-Monthly-Averages ratebase for the

Company as of September 30, 2005 in the column labeled Actual Results of Operation. The various line items are then adjusted for the summarized proforma and restating adjustments, as shown in the Adjusted Results of Operations column. This column is the source used to calculate the revenue deficiency. In the second to last column the revenue deficiency is added to the adjusted income statement and the impact on the operating income statement and ratebase is presented in the final column. The rest of this exhibit is composed of two sections, described below.

Pages 4-A through 4-C of this Exhibit No. ___(KRK-4) present a summary schedule of all the proforma and restating adjustments. The first column of numbers, on page 4-A, is the unadjusted net operating income for the year ended September 30, 2005 and the unadjusted ratebase for the same period. Each column to the right of the first column represents a proforma and/or a restating adjustment to net operating income or ratebase. Each of these adjustments has a supporting schedule, which is referenced by the page number shown in each column title.

The second to the last column, shown on page 4-C of the summary schedule, summarizes all of the adjustments and the final column shows the adjusted test period results used to calculate the revenue deficiency.

**Q. Please describe each adjustment, explain why it is necessary, and identify the effect on operating income or ratebase.**

A. I will explain the adjustments in the order as they are shown on the summary schedule, by reference to the column number and title of each adjustment.

**4.01 <u>Revenue and Purchased Gas</u>**

This restating and proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4.01, normalizes weather sensitive gas therm sales by eliminating the effect of temperature deviation above or below historical normals. It restates therms sold to reflect the weather normalized therms and then reprices the adjusted therms sold based upon the authorized weighted average cost of gas. This adjustment removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as municipal taxes, gas supply cost deferrals, the conservation tracker and the low income program. The associated expense for these direct pass through tariffs are removed in the other restating and proforma adjustments with the exception of the municipal tax expense, which is removed on line 21 of this adjustment and Schedule 106, the amortization of deferred gas supply costs which are removed on line 17 of this adjustment. A proforma adjustment is also included to reflect the revenue that would have been collected during the test year if the General Rate Case revenues from the 2004 general rate case had been in effect during the entire test period.

This adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.01, increases net operating income by $13,489,425.

**Q. Please continue describing the restating and proforma adjustments?**

A. The next adjustments are:

**4.02 <u>Federal Income Taxes</u>**

This schedule adjusts actual Federal Tax expense to the restated level based on the test year for this case. As PSE's normal tax year ends December 31st, this adjustment recalculates the test year using expenses and tax adjustments for the twelve months ended September 30, 2005.

The effect of this adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.02, is to increase net operating income by $490,787.

**4.03 <u>Tax Benefit of Proforma Interest</u>**

This proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.03, uses a ratebase method for calculating the tax benefit of proforma interest. Consistent with the approach adopted by this Commission in prior rate cases, the customers receive the tax benefit associated with the interest on debt used to support ratebase and construction work in progress that has associated tax deductible interest. The effect of this adjustment is to decrease net operating income by $7,280,941.

**4.04 Conservation**

This restating and proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.04, removes the amortization associated with the conservation tracker. The associated conservation revenues were removed in Adjustment 4.01.

The effect of this adjustment is to increase net operating income by $2,245,205.

**4.05 Bad Debts**

This restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years of history after removing the high and low years, which is the method used in PSE's 2004 general rate case. Each of the five years bad debt expense rate is calculated on the twelve months ended September 30 so that they are consistent with this filing's test year. The bad debt percentage for a given year is calculated by taking the actual write-offs for that year and dividing them by the net revenues for that year. The net test year revenues from line 6 are multiplied by the average bad debt percentage, line 8, to determine the amount of bad debt expense. This amount is compared to the actual test year level of bad debt expense on line 11 to determine the effect on income. This bad debt percentage is also used in the conversion factor when determining the final revenue requirement.

This adjustment, as shown on Exhibit No. ___(KRK-4), page 4-A, column 4.05, decreases net operating income by $236,343.

**4.06 <u>Miscellaneous Operating Expense and Ratebase</u>**

This restating and proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.06, adjusts the test year for several different items.

**1. <u>New York Stock Exchange Fees</u>**

This first adjustment pro forms in the change in cost for the Company's Common Stock Fees on the New York Stock Exchange. In the fall of 2005 the SEC approved a restructuring of the fees assessed by the NYSE. The fees are based on the number of shares outstanding and this adjustment is based on estimated shares to be outstanding during 2007. This will be adjusted during the course of this proceeding to reflect changes in the amount of shares expected in 2007.

**2. <u>Amortization of Deferred Taxes Regulatory Asset</u>**

The next adjustment is to pro form in the amortization of the regulatory asset associated with the deferred taxes discussed earlier in my testimony related to indirect overheads. (As discussed above and as explained by Mr. Story in his testimony, the IRS has changed the method of deduction for these indirect overhead costs and requires any utility that had previously deducted these items to reverse the deductions over the 2005 and 2006 tax years.) The Commission's order on October 26, 2005, approving the Company's accounting petition in

Dockets UE-051527 and UG-051528, allowed the Company to set up a regulatory asset account to track the carrying costs associated with the tax payments based on the turn around of the deductions associated with these overheads. The Commission allowed the Company to defer the carrying costs, with interest, associated with the deferred taxes that had to be repaid to the Federal Government in 2005 and 2006.

This adjustment amortizes this deferral over two years and includes the amortization of the carrying costs associated with the declining balance of this regulatory asset. The Company is proposing to amortize these costs for recovery over two years because that is the Company's recent experience regarding how often it needs to file general rate cases.

**3. Depreciation Expense on Construction Work In Progress ("CWIP") in service not transferred to plant**

This adjustment estimates the amount of depreciation expense associated with the CWIP that has been closed and is in-service but not yet classified to plant the ratebase adjustment for which is discussed next.

**4. Ratebase Adjustment**

The ratebase adjustment shown on Exhibit No. ___(KRK-4), page 4.06 is to add to ratebase Construction Work in Progress ("CWIP") that is closed and in-service but not yet classified to plant. This adjustment is consistent with prior cases and is necessary to properly reflect the ratebase that was in service during the test year.

The effect of all these miscellaneous adjustments is to decrease net operating income by $1,077,331 and to increase ratebase by $2,857,353.

**4.07 Property Taxes**

This proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.07, reflects the estimated property tax levy rates to be paid in 2006 based upon 2005 value. This adjustment is done in the same manner as the last general rate case and the levy rates will be adjusted to actual during the course of this proceeding.

The effect of this adjustment is to lower net operating income by $28,679.

**4.08 Excise Tax and Filing Fee**

This restating adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.08, adjusts the test year to actual expense for the State excise tax and Washington filing fee that should be recorded for these costs. The effect of this adjustment is to increase net operating income by $389,325.

**4.09 Rate Case Expenses**

In the Company's 2004 general rate case the Commission allowed a portion of the Company's 2004 rate case expenses to be deferred and amortized over three years. At the same time, the Commission changed the method for future recovery of rate case expenses to a "normalized" methodology. Based on recent prior cases, a "normal" level of expense for filing a general rate case was then determined and divided by an estimated time interval of three years to determine the annual amount to set in rates (half of which were included in the electric revenue requirement and half of which were included in the gas revenue requirement).

The Company has followed this method in the calculation of rate case expense for this case. The Company has used the history of expense levels for general rate cases since 2001 to determine a normalized level of expenditures by averaging the costs associated with the last two general rate cases. This average level of costs was then spread over two years for each type of case, which more accurately reflects the actual time frame that has been experienced between general rate case filings over the past several years.

The average cost for a general case using this methodology is $4.3 million. This cost is allocated 50% to electric and 50% to natural gas which results in a $1.07 million dollar annual cost for each energy group.

As to the deferred costs from the 2004 general rate case that the Commission ordered to be amortized for recovery over three years, the Company has used the yearly amount set in the 2004 general rate case to comply with the Commission order so that the amortization will be completed by March 2008.

The resulting amortization and normalized cost are then compared to the amount the Company had recorded in the test year for regulatory expense and the result decreases net operating income by $273,728 as shown on Exhibit No. ___(KRK-4), page 4-B, column 4.09.

**4.10 Property and Liability Insurance**

This proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.10, reflects the estimated premium increases for property and liability insurance expense. These costs are allocated between electric and natural gas depending on the purpose of the insurance. This adjustment will be updated to actual premiums during the course of the proceeding.

The effect of this adjustment is to reduce net operating income by $35,879.

**4.11 Pension Plan**

This restating adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.11, adjusts the test year to reflect cash contributions to the Company's qualified retirement fund. During 2003 the Company made a deductible cash contribution, as determined by its plan actuary, to the Pension Plan to help ensure that the plan remains fully funded. As allowed in prior general cases the Company has averaged the last four years of contributions and is requesting that average amount in current rates. The average contribution is allocated to electric and natural gas O&M based on salary distribution.

This adjustment also restates the expense associated with the Supplemental Executive Retirement Plan to an average of the last four years expense and allocates this expense between electric and natural gas based on salary distribution.

The effect of this adjustment is to reduce net operating income by $1,603,511.

**4.12 Wage Increase**

This proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.12, reflects the impact of wage increases and payroll tax changes, as described in the testimony of Mr. Tom Hunt, Exhibit No. ___(TMH-1T). For represented (union) employees, the adjustment annualizes the wage increases granted in 2005, 2006, and 2007. The percentage of wage increase for IBEW union employees from the test period through the rate year are 3% effective April 1, 2005, 3% effective April 1, 2006, and 3% effective April 1, 2007. The percentage of wage increase for UA union employees from the test period through the rate year are 3% effective October 1, 2005, 3% effective October 1, 2006, and 3% effective October 1, 2007. The 2005 and 2006 increases for both IBEW and

UA are contractual. The 2007 increases are not yet known and have been left at the 2006 contracted levels of 3% for purposes of this adjustment. The percentage of wage increase for management employees from the test period through the rate year are 3.04% effective March 1, 2005, 3% effective March 1, 2006, and 3% effective March 1, 2007. These management increases have been weighted by prior year actual salary increases, as in prior general rate cases. This is done in order to account for "slippage," as it is sometimes called, that occurs when new management employees are hired at lower salary rates than the more senior employees they are replacing.

The total proforma adjustment reflecting the impact of wage increases and payroll tax changes for both management and represented (union) employees, as discussed above, decreases net operating income by $1,393,820.

**Q. Please explain how these management increases are weighted by prior increases in order to adjust for slippage?**

A. Slippage is determined by measuring the difference between the average wage increase granted during each of a number of historical adjustment periods and the change between the average wage at the beginning and end of each of the same periods for the same class of employees. Projected wage increases then, for the same class of employees, are weighted, or reduced, by the slippage differential.

In order to perform the actual slippage calculation in this case, the Company first calculated the annualized payroll for all management employees for each of the last five years as of March 1st of each year. March 1st is the effective date of annual management salary adjustments. From this, the Company determined the average annual salary per management employee as of March 1st of each year and, in turn, the change in the average annual salary between years. For the years 2002 through 2005, this change was 1.50%, 3.95%, 1.05%, and 1.87% respectively, or 2.15% on average. This was compared to the average wage increase allowed for management employees during those same years of 2.72%, 2.88%, 2.98% and 3.04% respectively, or 3.03% on average. The 2.15% average change between the beginning and end of each adjustment year is 70.94% of the 3.03% average increase at the beginning of each year. This percentage then is applied to the expected compound wage increase of 6.92% from the end of the test year through the rate year ending December 31, 2007, to yield a 4.91 % wage adjustment for management employees after taking slippage into consideration.

## 4.13 Investment Plan

This proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.13, adjusts the Company portion of investment plan expense to reflect the additional expense associated with the wage increases and is based on the current employee contribution rates.

Net operating income is decreased by $59,018 as the result of this adjustment.

**4.14 Employee Insurance**

This proforma adjustment updates the test year insurance payments to the amount for the rate year. For represented employees, the estimated cost is based on the average Company contribution amount of $750 per eligible employee per month. The amounts are the result of negotiations between PSE and the IBEW union and PSE and the UA union. The same average rate was also applied to salaried employees.

These costs are allocated to electric and natural gas based on payroll distribution and then expense, construction and other accounts based on the percentage of payroll charged to these accounts during the test year. The portion of the insurance payments associated with expense during the test year has been determined to be 62.32%.

The effect of this adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.14, is to decrease net operating income by $418,486.

**4.15 Incentive Compensation**

This restating adjustment uses a four year history of incentive compensation made to employees. In his testimony, Mr. Hunt discusses why this expense is appropriate for ratemaking consideration and how the program is similar to the previously allowed incentive compensation programs.

For this calculation, we have used the years 2002 through 2005 and allocated the four-year average to electric and natural gas based on payroll distribution. The incentive is then allocated to O&M and other accounts based on where payroll was charged during the test year. This is consistent with the treatment accorded in the last general rate case. This amount is then compared to actual expenses during the test year and results in an increase in net operating income of $442,417, as shown on Exhibit No. ___(KRK-4), page 4-B, column 4.15.

**4.16 <u>Interest on Customer Deposits</u>**

This proforma adjustment to operating income is the result of customer deposits being treated as a reduction to ratebase. This proforma adjustment adds the cost of interest for this item to operating expense. This presentation is consistent with decisions in prior general rate cases, and as shown on Exhibit No. ___(KRK-4), page 4-C, column 4.16, reduces net operating income by $131,750.

**4.17 <u>Deferred Gains/Losses on Property Sales</u>**

The purpose of this restating and proforma adjustment is to provide the customer with the net gains or losses from sales of utility real property since the last general rate case. The gains and losses are allocated to gas and electric based on the use of the property. The amount of the net gain is amortized over a three-year period, with the deferred amount being included in working capital. This adjustment is done in compliance with the settlement agreement for property sales from Docket UE-89-2688-T.

This adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.17, increases net operating income by $456,881.

**4.18 General Office and Crossroads Relocation**

During the test year the Company relocated employees from its Bellevue General Office Building and its Crossroads Building to the PSE Building. The purpose of the consolidation was to bring key work groups and support functions together and avoid the cost of a major upgrade that would have been required on the 50 year old General Office building. This restating adjustment removes the General Office and Crossroads Building from operating expense and ratebase. The adjustment also pro forms in the yearly cost associated with the lease of the PSE Building. The purpose of this consolidation is discussed by Mr. Story in his testimony.

The effect of this adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.18, is to decrease net operating income by $751,245 and decrease ratebase by $1,746,177.

### 4.19 Low Income Amortization

This proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.19, removes amortization of the Company's Low Income Program. Such costs are recovered through a tracker outside of general rates and the revenues associated with this program were removed in the revenue adjustment.

The effect of this adjustment is to increase net operating income by $1,361,790.

### 4.20 Director and Officer Insurance

This restating adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.20, removes the portion of Director and Officer insurance that should be allocated to Company subsidiaries. The amount is determined by dividing non-utility assets by Puget Sound Energy, Inc. assets and applying that percentage to this insurance cost.

The effect of this adjustment is to increase net operating income by $3,192.

### 4.21 Pipeline Capacity Additions

#### 1. Everett Delta Pipeline Expansion

The Everett Delta pipeline expansion, which was completed and placed into service in November 2004, was necessary to reduce the reliance on the North Seattle lateral as the sole supply for a large portion of the Company's gas customer base and to provide increased gas supply for existing needs and anticipated growth in the North Seattle to Everett system and the Marysville area (at the northernmost limits of the system).

Northwest Pipeline Corporation ("NWP") built and operates the pipeline under Federal Energy Regulatory Commission ("FERC") authority, but the pipeline itself is owned by PSE and leased back to NWP. In accordance with the Lease Agreement, PSE is leasing the pipeline to NWP for the first five years of service. At the end of the lease, PSE and NWP will petition FERC for approval for NWP to abandon service to PSE, thus enabling PSE to operate the gas pipeline. PSE will also request a Pressure Authorization from the Commission for operation of the pipeline. The meter station and scrubber will continue to be operated by NWP.

During the five year lease period, NWP is paying PSE a monthly lease amount based on PSE's results of operations of the Everett Delta gas pipeline and its authorized rate of return on the investment, including recovery of depreciation and other expenses, consistent with normal rate-making practices (cost-of-service basis). NWP is charging PSE a demand charge for the transportation of gas through the pipeline equal to the lease payment plus NWP's operations and maintenance costs. The Lease Agreement provides for an annual demand charge adjustment based on the actual results of operations, and there is an annual true-up of the demand charge to actuals. In addition, the demand charge is recovered through the Company's PGA Mechanism during the lease period. Thus, any revenue requirement variation in the test year related to the Everett Delta Pipeline Expansion can be eliminated for general ratemaking purposes.

At the end of the lease period, it will be necessary to have a revenue neutral transition tariff in place to transfer the recovery of the Everett Delta pipeline expansion from the PGA Mechanism into general rates, in order to ensure proper general ratemaking treatment. However, the Company is not proposing a transition tariff in this filing.

The proforma adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.21, removes the test year revenue requirement discrepancy associated with the Everett Delta pipeline expansion. The effect of this adjustment is to increase net operating income by $176,569.

**2. <u>Evergreen Pipeline Capacity Purchase</u>**

**Q. Is there a ratemaking adjustment required for the Duke Energy Trading and Marketing ("DETM") pipeline capacity purchase discussed by Mr. William Donahue in his testimony, Exhibit No. ___(WFD-1T)?**

A. The DETM transaction, which occurred subsequent to the test year, relates to purchases of existing contracts for pipeline capacity on existing pipelines. A separate accounting petition, Docket No. UG-060019, was filed by the Company, and was approved by the Commission on January 25, 2006. This accounting order provides for the ratemaking treatment of this transaction and no ratemaking adjustment is necessary in this proceeding as a result.

**Q. Why did the Company request an accounting order?**

A. As a result of the transaction with DETM, the Company received pre-paid discounts of $42 million and $13 million, respectively for the Northwest Pipeline ("Northwest") and Westcoast Energy Inc. ("Westcoast") capacity contracts described by Mr. Donahue in his testimony. The Northwest capacity is not needed for customers until 2010 or 2011 and the Westcoast capacity is needed currently, but the assumed tariff rates are more than current market value. The discounts were paid to compensate for the Northwest capacity payments that must be made until 2010 or 2011 when the capacity is needed and the difference between the assumed tariff rates and market value of the Westcoast capacity.

The Company requested the accounting order so that it would be able to defer the income (pre-paid discount), or "park" it so to speak, as a deferred credit or other regulatory liability on the balance sheet, for later matching against the related expense (capacity payments) in the income statement. The amounts included as such in other regulatory liabilities are those that would have been included in net income or other comprehensive income in the current period under the general requirements of the Uniform System of Accounts, but for it being probable that such items will be included in a different period for purposes of developing rates that the utility is authorized to charge. By properly matching revenues and expenses in this manner, the Company's results of operations are not distorted by the timing differences in the income statement arising from the transactions.

**Q. What would be the ratemaking consequences absent the Commission's accounting order regarding the payments under the DETM contracts?**

A. Absent an accounting order, the Company would have to report and footnote the unusual income on its financial statements in the current period. For ratemaking purposes, it would restate its results of operations consistent with the treatment requested and authorized in the accounting order. Ratebase would only be affected to the extent working capital changes, but would not be adjusted for rate making purposes since it would be the same whether there is an accounting order or not. In any event, it can not be determined at this time what the affect on ratebase might be. That would only become apparent in a future test period.

**Q. Is there any interest obligation in connection with the $42 million received from DETM for the Northwest Pipeline capacity which the Company has deferred and recorded as a regulatory liability?**

A. No. The Company has purchased capacity that it anticipates will be needed in 2011. In so doing, the Company has created an obligation, or liability, to the pipeline to purchase the capacity at a price that compensates the Company for such capacity purchases until it is needed. There is no shareholder interest to account for since the structure of the transaction involved a payment from DETM to the Company. There is also no customer interest to account for because the Company's customers did not provide any capital to effect this transaction. Similar principles apply to the $13 million received for the Westcoast contract, and no interest is due to the Company or customers.

## 4.22 **Depreciation and Amortization**

Since the mid 1980's, an adjustment has been included in the Company's general rate case filings which pro formed test year depreciation expense to an average-of-monthly-averages ("AMA") calculation based on the AMA plant balances included in the test period ratebase. The Company is proposing that actual depreciation expense for a test period be used in calculating a revenue deficiency unless there is a change in depreciation rates or there is a restatement needed to properly reflect depreciation expense. The same applies to electric ratebase and Mr. Story explains the reasons for making this change in his testimony.

The impact of this adjustment as proposed by the Company reflects no change to net operating income or ratebase, as shown on Exhibit No. ___(KRK-4), page 4-C, column 4.22. We have provided a calculation of the AMA depreciation adjustment in the accounting workpapers in compliance with WAC 480-07-510(3)(b).

**Q. In Order No. 6 in Docket No UG-040640, the Company's last general rate case, the Commission set forth a requirement that the test year level of depreciation expense related to the Company's gas water heater and conversion burner rental programs be continued until PSE's next general rate proceeding. Has the Company recorded the proper level of depreciation in accordance with the Order?**

A. Yes, test year depreciation for the Company's water heater and conversion burner rentals in that proceeding was $8,646,741, and rental depreciation has been maintained at that level subsequent to the order.

**Q. Are you proposing a depreciation adjustment for the gas water heater and conversion burner rental program in this case?**

A. No.

**Q. The Commission further indicated in its Order that at the time of PSE's next general rate proceeding, the issue may be reexamined. Have you reexamined the issue in this proceeding?**

A. Yes. Although the revenue requirement for water heater and conversion burner rentals continues to decline, the Company recommends that the associated test year level of depreciation expense be continued until PSE's next general rate proceeding or until the Commission decides otherwise.

**Q. Would you please explain the basis for your recommendation?**

A. In Order No. 6 in Docket No UG-040640, the Commission stated at paragraph 226 that it would "accept Staff's alternative proposal, rejecting its proposed Adjustment 2.17 and the associated ratebase adjustment, but requiring that the test year level of depreciation expense be continued until PSE's next general rate proceeding."

Staff's alternative proposal, set forth in its post-hearing brief, recommended that "the test year level of depreciation expense related to water heater and conversion burner rentals be maintained until the Company's next general rate case. This will ensure that customers will not provide a greater recovery of depreciation expense than would otherwise be in place after September 1, 2005." In the Order, it was noted that this proposal apparently would result in a credit balance (*i.e.,* credit for customers) after about 2006, because at that point the $31 million in ratebase will have been fully depreciated and customers will be paying about $8 million per year in depreciation for a ratebase asset that no longer exists.[1]

Subsequent to the test year in the Company's 2004 general rate case, a plant adjustment was made resulting in the posting of previously unclassified rental water heater and conversion burner units from retirement work in progress to the depreciation reserve. Consequently, the rental plant values are currently

[1] Order No. 06, Docket No. UG-040640 et al., at ¶ 223.

$11 million higher than expected during the 2004 general rate case and it will take longer to achieve the planned depreciation at the $8 million per year rate.

Accordingly, to address the same concerns that were expressed in the 2004 general rate case, the Company recommends that the test year level of depreciation be continued. This will ensure that customers do not provide a greater recovery of depreciation expense than would otherwise be in place and that these plant balances will be reduced through depreciation to their appropriate values.

**Q. How did the water heater and conversion burner rental program originally become a contested general rate case issue?**

A. In its 2001 general rate case, Docket Nos. UE-011570 et al., the Company filed a new depreciation study which showed that water heater and conversion burner rental equipment had been significantly under depreciated for a number of years. The Company should have been recovering more through depreciation from historical rental customers than it had been. Consequently, new and significantly higher rental depreciation rates were proposed and agreed upon.

Because of this and the resulting rate spread and rate design implemented to begin recovering the new rates, a higher burden was placed on both rental and non-rental customers than before. Since it would not be appropriate to put the entire burden of rental depreciation issues related to prior years on current rental customers, only a portion was allocated to current rental customers. There was also a concern that raising rental rates too far or fast would cause attrition in rental customers and reduced recovery of rental costs in turn.

The Company believes that its proposal in this case is an appropriate and reasonable next step to take in working toward resolving this historic rental depreciation issue.

## IV. CALCULATION OF THE REVENUE DEFICIENCY

**Q. Would you please explain what is presented in Exhibit No. ___(KRK-5)?**

A. This Exhibit presents the calculation of the revenue deficiency based on the pro forma and restated test period. The different pages in this Exhibit are:

**5.01 <u>General Rate Increase</u>**

This schedule, shown on Exhibit No. ___(KRK-5), page 5.01, shows the test period proforma and restated ratebase, line 1, and net operating income, line 6. Based on $1,180,351,743 invested in ratebase, an 8.76% rate of return and $78,261,323 of net operating income the Company would have a revenue deficiency of $40,439,958.

**5.02 <u>Cost of Capital</u>**

This schedule, shown on Exhibit No. ___(KRK-5), page 5.02, reflects the proposed capital structure for the Company during the rate year and the associated costs for each capital category. The capital structure and costs are presented in the testimony of Mr. Donald Gaines, Exhibit No. ___(DEG-1CT). The rate of return is 8.76% and 7.57% net of tax.

**5.03 <u>Conversion Factor</u>**

The conversion factor, shown on Exhibit No. ___(KRK-5), page 5.03, is used to adjust the net operating income deficiency by revenue sensitive items and Federal income tax to determine the total revenue deficiency. The revenue sensitive items are the Washington State utility tax, Washington WUTC filing fee, and bad debts. The conversion factor used in the revenue requirement calculation, taking into consideration the adjustments discussed earlier, is 62.16003%.

## V. PROPOSED REVISION TO THE PGA MECHANISM

**Q. Please describe the Company's PGA Mechanism**

A. As is typical in the industry, the Company does not make a profit on the sale of the natural gas it acquires on behalf of its customers. Instead, the cost of acquiring natural gas supplies is recovered as a dollar-for-dollar pass-through in base rates, which are adjusted periodically through the PGA Mechanism.

Technically, the PGA Mechanism is a rate adjustment clause that enables the Company to timely recover the cost of gas it purchases without proceeding with a general rate case. It does this by setting base rates through a general rate proceeding using an estimated cost of gas and then adjusting for any differences by accumulating excess gas costs or gas cost savings in a deferral account. The excess or savings in the deferral account is passed through to customers in periodic tariff filings – generally every twelve months.

**Q. Why is the PGA Mechanism important?**

A. The PGA Mechanism enables the Company to communicate current pricing trends to customers and at the same time insulate them from normal fluctuations in the market price of gas. This is important because the cost of the natural gas consumed by customers typically comprises more than half of their PSE gas bill and the price of natural gas can vary significantly in between general rate cases. The deferral account helps smooth these ups and downs, but consistent upward or downward market pressures will roll through in the nature of rate increases or decreases, respectively, within several months of these market trends.

This price volatility also makes the PGA Mechanism critical to the Company's financial strength and to fair rates for customers. Otherwise, prices that are higher than estimated in the Company's most recent rate case would rapidly degrade the Company's earnings. For example, a 25% variation or swing in the cost of purchased natural gas could amount to more than the Company's entire earnings capability of its gas operations. Prices that are lower than estimated in the Company's most recent rate case would rapidly result in customers paying more than was determined to be fair and reasonable in that rate case from the perspective of cost-based ratemaking.

**Q. Please explain the revision the Company is proposing to its PGA Mechanism.**

A. As discussed by Mr. Mills, the Company is proposing to open a new line of credit that is dedicated to supporting the Company's wholesale market hedging activities. The Company is proposing in this case that the costs associated with such a credit facility that are used to support transactions for the core gas portfolio be passed through the PGA Mechanism. The Company is also proposing to track the fees and costs of this new credit line that are associated with electric portfolio hedging and pass them through as part of the Company's Power Cost Adjustment ("PCA") Mechanism, as described in Mr. Story's testimony.

The Company proposes to track the set up fees and any interest costs in separate accounts from other bank fees and interest payments so that the costs would be easily identifiable and could be audited for reasonableness. As further explained by Mr. Mills in his testimony, it would be a relatively simple matter for the Company to allocate that portion of the costs associated with the new credit facility to the electric or core gas portfolios.

**Q. How would this change be implemented?**

A. The Company is proposing a modification of its Purchased Gas Adjustment Mechanism tariff schedule, Rule No. 26, to effect the change. The revised tariff schedule is included in Exhibit No. ___(JKP-11).

**Q. Are you proposing an adjustment for the PGA in this case?**

A. No.

## VI. PSE'S PROPOSALS TO ADDRESS REGULATORY LAG AND ATTRITION RELATED TO GAS OPERATIONS

### A. Discussion and Analysis of Gas Operations Regulatory Lag and Attrition

**Q. Mr. Story discusses regulatory lag and attrition at length in his testimony and particularly with regard to electric operations. Is the Company currently being impacted by regulatory lag and attrition on its gas operations?**

A. Yes, the Company is particularly impacted with respect to its natural gas service. Although the Company has the PGA Mechanism, which I discussed earlier, this addresses only the potential mismatch between commodity costs built into rates and current market costs. The PGA Mechanism does not address significant regulatory lag and attrition problems associated with the Company's high level of capital investment in natural gas infrastructure to address customer growth, maintenance of its aging system, and increased safety regulations or other requirements. As discussed by Ms. Sue McLain in her testimony, on average, the Company has made investments (other than for new customer connections) of approximately $60 million in gas infrastructure each year since 2001. PSE anticipates investments of $113 million will be required in 2006 and $89 million in 2007 for similar types of gas infrastructure. This represents a 45% increase over PSE's 2004 and 2005 investments of $140 million, and system analysis indicates that similar ongoing gas system investments will be needed for several years beyond 2007

**Q. Why are these capital investments causing an attrition problem?**

A. The problem is largely caused by the lag between the time when the investments are made and the time when rates reflecting such costs become effective. The consequence is particularly acute with respect to replacement of PSE's aging infrastructure, because plant put into ratebase twenty or thirty years ago has a much lower average cost then the capital additions which are replacing it. For example, as Ms McLain explains in her testimony, the cost to install one foot of 2-inch diameter plastic gas main has increased from $3 per foot in 1974 to nearly $22 per foot in 2004. Contributing to this rise is the fact that not only have the costs of materials and labor increased but current requirements for construction permitting and inspection and preventative actions to minimize soil erosion have also grown.

**Q. How does the Company propose to address these issues affecting its gas operations?**

A. As discussed by Mr. John Story, the Company is proposing a new Depreciation Tracker that would true up revenues for changes in depreciation expense related to natural gas transmission and distribution capital investment.

**Q. Is the Company requesting an attrition adjustment for its gas operations in this case based on the trended methodology that the Commission has accepted in some historic rate cases?**

A. No, as Mr. Story explains in his testimony, we believe that the measures we are proposing better address regulatory lag and attrition in the Company's current operating environment. However, for informational purposes, the Company prepared an analysis consistent with this historic methodology for both its natural gas and electric service. The general guidelines used and trending methodology applied in this analysis are the same as Mr. Story describes in his testimony.

**Q. What did the trended attrition analysis for gas operations show?**

A. Once the impacts of the PGA related costs were removed and ratebase was adjusted for the impact of the bonus tax depreciation, the estimated attrition between the test year and the rate year is calculated to be $34.9 million net operating income under recovery. This analysis is shown in Exhibit No. ___(KRK-6), which is explained in Exhibit No. ___(KRK-7).

**Q. How would these results be applied if the Company was requesting an attrition adjustment in this filing based on the trended methodology?**

A. If the Company were requesting a traditional attrition adjustment in this case, the $34.9 million net operating income under recovery would be added to the Company's gas revenue requirement net operating income deficiency for this filing.

**Q. Did the Company perform any other analysis as a check on the traditional trended attrition analysis?**

A. Yes. In addition to the trending of revenues and costs as described above, we compared the results to the Company's rate year financial forecast of revenue and costs.

**Q. What was the result of this analysis?**

A. The financial forecast projects that there will be an approximately $20.4 million net operating income under recovery in the rate year, which is moderately less than the trended attrition result discussed above. The results of this analysis, put on a comparable basis, are shown on page 6.02 of Exhibit No. ___(KRK-6).

**Q. What were the major differences between the trended results of attrition and the financial model?**

A. As can be seen on line 7 page 6.02 of this exhibit, the primary difference is largely the result of higher net sales forecast in the Company's financial model. Forecast sales volumes are 2.15% greater than the attrition analysis and greater sales margins are forecast as a result. Also, the attrition analysis indicates much higher growth in Administrative and General Expenses. Such differences are not uncommon when comparing results, given the differing methodologies employed, and the total variation between the attrition results and the financial forecast is not large. In general, it can be concluded that given the requested rate relief, the Company's gas operations will be impacted by the effects of attrition by $20 to $30 million in the first rate year, absent any mitigating measures.

## B. <u>The Depreciation Tracker and Natural Gas Decoupling Mechanism Will Help Address These Issues</u>

**Q. Will the Company's proposed Depreciation Tracker eliminate the erosion in cost recovery caused by the attrition you describe above?**

A. It will not eliminate the problem, but it will help. As described in Mr. Story's testimony, the Depreciation Tracker only adjusts for the increased depreciation expense associated with these capital investments. This means that rates are adjusted for the return-of, but not for the return-on these investments. The return-on the investment would not be addressed until the next general rate proceeding.

It is in this regard that the Depreciation Tracker helps, but it is only part of the solution. Other measures, such as the Company's proposed gas decoupling mechanism, would still be needed to better address the affects of attrition.

**Q. Will the Company's proposed decoupling mechanism mitigate the affects of attrition as described above?**

A. Yes, the attrition problems caused by increased investments in energy efficiency and natural gas infrastructure, combined with declining use per natural gas customer, will be mitigated by the decoupling mechanism that is described in Mr. Ron Amen's testimony, Exhibit No. ___(RJA-1T).

## VII. CONCLUSION

**Q. Does this conclude your testimony?**

A. Yes, it does.

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