EXHIBIT NO. ___(KRK-1T)
DOCKET NO. UE-07___/UG-07___
2007 PSE GENERAL RATE CASE
WITNESS: KARL R. KARZMAR

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____**

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

DECEMBER 3, 2007

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF KARL R. KARZMAR

CONTENTS

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, Inc. ("PSE" or the "Company"). 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 will first discuss test year financial statements and ratebase. This will include discussion of a revision to the Company's electric and gas working capital calculation to provide a more straightforward approach and to correct for a deficiency in the way it was being calculated. I will describe the allocation of common expenditures between electric and natural gas. Then I will discuss the current results of operations compared to the results of operations in the last general rate case and the resulting causes of the current revenue deficiency. I will next discuss the gas pro forma and restating adjustments, including a proposed change in the manner in which the Company recovers its costs associated with the Everett Delta Pipeline Expansion.

Finally, I will discuss the gas general rate case revenue deficiency, which is $56,770,922, based upon the adjusted test period operating revenues of $1,068,194,800 and represents a 5.31% average increase.

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 Exhibit No. ___(KRK-3) presents a comparison between the unadjusted gas income statement for the year ending September 30, 2005, the test year for Docket No. UE-060266 et al. (the "2006 general rate case") and the unadjusted gas income statement for the year ending September 30, 2007, the test year for this general rate case filing. Page 3.02 of Exhibit No. ___(KRK-3) presents the gas balance sheet for the same time periods, and page 3.03 of Exhibit No. ___(KRK-3) presents the ratebase calculation for the current test year prior to any pro forma and restating adjustments. Please see the second exhibit to the prefiled direct testimony of Mr. John H. Story, Exhibit No. ___(JHS-3), for the equivalent schedules for electric operations.

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

A. Yes, with one exception. The working capital calculation has been revised to more accurately reflect the total amount and allocation between electric, gas and non-utility functions. The calculation of the test year ratebase with this revision, but before restating and pro forma adjustments, is shown on page 3.03 of Exhibit No. ___(KRK-3).

Q. Would you please explain the working capital calculation?

A. This is the measure, for ratemaking purposes, of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations in order to bridge the gap between the time expenditures for services are required to be provided and the time recovery occurs. 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 accounted for elsewhere by investment in plant or otherwise 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 allowed to earn a return, is deducted. A second deduction is made for non-operating assets that are not earning a return 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 a 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. This represents the capital needed for fuel inventory, such as underground storage, materials and supply inventories, prepayments and cash working capital for example. The gas and electric working capital calculation is shown in Exhibit No. ___(KRK-3), page 3.04.

/////

/////

Q. Please explain how you have revised the working capital calculation in this case.

A. Historically, since the merger in 1997 of Washington Energy Company and Washington Natural Gas Company with and into Puget Sound Power & Light Company in Docket UE-960195, the Company has calculated the electric and gas working capital requirement separately and independently of each other as if they each stood alone with separate investor supplied working capital requirements. In this case however, the Company has taken a much more straightforward approach and calculated the working capital allowance on a combined basis. In utilizing this consolidated methodology, all of the components involved in the development of working capital, including the gas, electric and nonutility components, are evaluated together rather than independently. As a result, a ratable apportionment can be more readily validated.

Q. Please explain how this is done.

A. The combined working capital calculation is shown in detail in Exhibit No. ___(KRK-3), page 3.04, but I will simplify and condense it here for illustrative purposes. Looking at Table 1 below, where dollars are expressed in thousands, investor supplied working capital of $144,745,000 on line 8 is the average invested capital on line 1 minus the total average investment on line 7 and is detailed in Exhibit No.___(KRK-3) page 3.06. Based on its percentage of total average investment, working capital is then prorated based on the relationship of the gas and electric operating investment on lines 3 and 4 and the non-operating investment on line 6. As a result, the working capital allocation to gas and electric utility operating investments and non-utility operating investments is: $37,082,000; $90,806,000; and $16, 857,000, respectively, on lines 10, 11 and 13, which is proportional to gas and electric utility operating investments on lines 3 and 4, and to non-utility operating investments on line 6 of $1,308,708,000; $3,204,772,000; and $594,944,000, respectively, as they should be.

Table 1

	Combined Working Capital Calculation	**($ in thousands)**	
1	Average Invested Capital	$5,253,169	
2			
3	Gas Operating Investment	$1,308,708	
4	Electric Operating Investment	$3,204,772	
5	Total Utility Operating Investment	$4,513,480	
6	Non-Operating Investment	$594,944	
7	Total Investment	$5,108,424	
8	Total Investor Supplied Working Capital	$144,745	
9		2.83%	(= 144,745 / 5,108,424)
10	Utility Allowance on Gas Operating Investment	$37,082	(= 2.83% x 1,308,708)
11	Utility Allowance on Electric Operating Investment	$90,806	(= 2.83% x 3,204,772)
12	Total Utility Allowance	$127,888	
13	Non-Operating Working Capital	$16,857	(= 2.83% x 594,944)
14	Total Investor Supplied Working Capital	$144,745	

Q. Are the same results achieved when calculating working capital separately for the electric and gas results of operations?

A. Yes, computing the working capital allowance for electric and gas operations separately and independently of each other, as if they each stood alone with separate investor supplied working capital requirements, yields the same answer, when calculated correctly. Table 2 below illustrates that calculation. Table 2 shows first, the gas calculation and second, the electric computation. Looking at the gas working capital calculation in Table 2, gas working capital is calculated on lines 15 through 29 and electric is separately calculated in lines 30 through 44. In the gas calculation, investor supplied working capital of $144,745,000 on line 25 is the average invested capital on line 15 minus the total average investment on line 24. Based on the percentage, on line 26, of total average investment, working capital then is prorated on lines 27 and 28, based on the relationship of the gas operating investment on line 19 and the non-operating and electric operating investment on line 23. Electric working capital is calculated in a similar manner. The non-operating working capital of $16,857,000 is the result of the non-operating and electric operating working capital of $107,663,000 on line 28 less the $90,806,000 electric component on line 42 and similarly line 43 less line 27. Once again, it can be seen that the working capital allocation to gas and electric utility operating investments and non-utility operating investments of $37,082,000; $90,806,000; and $16,857,000, respectively, are proportional to gas and electric utility operating investments, and to non-utility operating investments of $1,308,708,000; $3,204,772,000; and $594,944,000, respectively, as they should be.

/////

/////

/////

Table 2

	Gas Working Capital Calculation	**($ in thousands)**	
15	Average Invested Capital	$5,253,169	
16	Gas Operating Investment		
17	Gas	$1,242,940	
18	Common	$65,768	
19	Total Gas Operating Investment	$1,308,708	
20			
21	Total Non-Operating Investment	$594,944	
22	Electric Operating Investment	$3,204,772	
23	Total Non-Operating and Electric Operating	$3,799,716	
24	Total Average Net Investment	$5,108,424	
25	Total Investor Supplied Working Capital	$144,745	
26	As a Percent of Average Investment	2.83%	(= 144,745 / 5,108,424)
27	Utility Allowance on Gas Operating Investment	$37,082	(= 2.83% x 1,308,708)
28	Non-Operating and Electric Working Capital	$107,663	(= 2.83% x 3,799,716)
29	Total Investor Supplied Working Capital	$144,745	

	Electric Working Capital Calculation	**($ in thousands)**	
30	Average Invested Capital	$5,253,169	
31	Electric Operating Investment		
32	Electric	$3,081,823	
33	Common	$122,949	
34	Total Electric Operating Investment	$3,204,772	
35			
36	Total Non-Operating Investment	$594,944	
37	Gas Operating Investment	$1,308,708	
38	Total Non-Operating and Gas Operating	$1,903,652	
39	Total Average Net Investment	$5,108,424	
40	Total Investor Supplied Working Capital	$144,745	
41	Investor Supplied Working Capital as a %	2.8335%	(= 144,745 / 5,108,424)
42	Operating Electric Working Capital	$90,806	(= 2.8335% x 3,204,772)
43	Non-Operating and Gas Working Capital	$53,939	(= 2.8335% x 1,903,652)
44	Total Investor Supplied Working Capital	$144,745	

Q. Is the calculation in Table 2 consistent with the methodology applied in the 2006 general rate case?

A. Yes it is consistent with the methodology applied in the 2006 general rate case except that Table 2 reflects a correction to a "spreadsheet error" that was built into the model used in the 2006 general rate case and in the two prior cases. The spreadsheet error improperly includes electric and gas working capital amounts with the electric and gas operating investment. Table 3 below demonstrates the effect if the spreadsheet error is perpetuated in this case. Line 54 of Table 3 includes electric working capital amounts with the electric operating investment. Likewise, line 69 of Table 3 includes gas working capital amounts with the gas operating investment. Working capital accounts should be excluded from the determination of investor supplied working capital.

The error becomes even more apparent in Table 3, below, when one compares the working capital allocation to (1) gas utility operating investment, $15,787,000 (line 59); (2) electric utility operating investment $50,902,000 (line 74); and (3) non-utility operating investment $78,056,000 (line 60 plus line 75, the way this spreadsheet is constructed). These working capital allocations clearly are not proportional to gas and electric utility operating investments, and non-utility operating investments of $1,308,708,000; $3,204,772,000; and $594,944,000, respectively, as they should be.

/////

/////

/////

/////

Table 3

	Gas Working Capital Calculation	($ in thousands)	
47	Average Invested Capital	$5,253,169	
48	Gas Operating Investment		
49	Gas	$1,242,940	
50	Common	$65,768	
51	Total Gas Operating Investment	$1,308,708	
52			
53	Total Non-Operating Investment	$594,944	
54	Electric Operating Investment & Electric WC accounts	$3,286,904	(= 3,204,772 + 82,132)
55	Total Non-Operating and Electric Operating	$3,881,848	
56	Total Average Net Investment	$5,190,556	
57	Investor Supplied Working Capital	$62,613	
58	As a Percent of Average Investment	1.21%	(= 62,613 / 5,190,556)
59	Utility Allowance on Gas Operating Investment	$15,787	(= 1.21% x 1,308,708)
60	Non-Operating and Electric Working Capital	$46,826	(= 1.21% x 3,881,848)
61	Investor Supplied Working Capital	$62,613	

	Electric Working Capital Calculation	($ in thousands)	
62	Average Invested Capital	$5,253,169	
63	Electric Operating Investment		
64	Electric	$3,081,823	
65	Common	$122,949	
66	Total Electric Operating Investment	$3,204,772	
67			
68	Total Non-Operating Investment	$594,944	
69	Gas Operating Investment & Gas WC accounts	$1,371,321	(= 1,308,708 + 62,613)
70	Total Non-Operating and Gas Operating	$1,966,265	
71	Total Average Net Investment	$5,171,037	
72	Investor Supplied Working Capital	$82,132	
73	Investor Supplied Working Capital as a %	$1.5883%	(= 82,132 / 5,171,037)
74	Operating Electric Working Capital	$50,902	(= 1.5883% x 3,204,772)
75	Non-Operating and Gas Working Capital	$31,230	(= 1.5883% x 1,966,265)
76	Investor Supplied Working Capital	$82,132	
77	Utility Allowance on Electric Operating Investment	$50,902	
78	Total Investor Supplied Working Capital	$144,745	(= 62,613 + 82,132)

This spreadsheet error resulted in an overlap of the distinct elements comprising the working capital requirement determination. In the process the Company did not reconcile the Company's total working capital need against the sum of the parts (gas working capital, electric working capital and non-utility working capital). The practice of incorrectly and independently calculating the working capital requirement resulted in an understatement of investor supplied utility working capital. With this filing, the Company has corrected that computational deficiency, thereby eliminating the resulting distortion and understatement of utility working capital.

Q. Having corrected for the computation error described above, is this otherwise consistent with the methodology applied in the 2006 general rate case?

A. Yes it is, but there is an additional adjustment to the calculation of electric working capital, related to Construction Work in Progress ("CWIP"), that is shown on Exhibit No. ___(KRK-3), page 3.04, which I have not discussed here because it is made after all of the foregoing, and we are proposing no change with respect to its calculation. This adjustment excludes electric CWIP from the allocation process as the result of a WUTC Staff recommendation and subsequent Commission order in Cause No. U-83-54.[1] The exclusion of electric CWIP in this case is consistent with the treatment in the Company's prior electric filings since that case. This adjustment is made so that non-operating working capital is not

[1] Testimony of Merton Lott, WUTC Accounting Analyst, June 1984 at page 13, beginning on Line 6. "It should be noted that I have proposed a slightly different method of allocating working capital than was accepted by the Commission in Cause U-81-41, a prior Puget case. In that case, working capital was allocated to all investments including CWIP. The major reason I excluded CWIP from the allocation process is that I do not believe that construction activities would tend to have positive working capital related to them." Accepted in the Fourth Supplemental Order in that Cause at page 17, without endorsement.

distorted by the exclusion of CWIP from being treated as part of electric operating investment for allocation purposes.

Q. Why is this adjustment necessary?

A. This adjustment is made as an alternative to another accepted method of allocation, which would instead include electric CWIP with other utility non-operating investments before allocating working capital.[2] This adjustment effectively causes working capital to be adjusted between electric utility operating investment and non-operating investment exclusive of CWIP. As discussed previously, this is done to be consistent with a prior case, where a Staff witness did not believe CWIP required any working capital, but, in the process of elimination, made this adjustment so as not to distort the remaining working capital associated with non-operating investments.

Q. Is gas working capital allocated in the same manner?

A. No. Gas has been treated differently based on Commission precedent. Gas working capital does not include the above discussed CWIP refinement. Although it makes sense for both the gas and electric working capital to be

[2] Puget Sound Power & Light Company general rate case, Cause No. U-81-41, Second Supplemental Order, dated March 12, 1982, at page 9. "We accept the staff investor- supplied working capital allowance calculation method, as we have done in many prior proceedings, because it is shown here to represent the better and more accurate calculation of the actual investor-supplied contribution to the working capital needs of the Company." Re: balance sheet investor supplied working capital approach of Staff witness Michael P. McE11iott, testimony dated November 24, 1981.

calculated similarly, the Company is not proposing a conforming change for gas in this proceeding.

Q. How does the current working capital allowance compare to the working capital allowance in the 2006 general rate case?

A. Before adjusting for electric CWIP, the gas and electric working capital in this case are $37,082,000 and $90,806,000, respectively, compared to $10,823,000 and $23,135,000, respectively, in the 2006 general rate case (as filed but corrected for the above described spreadsheet error).

Q. What is causing such a sizeable increase in working capital?

A. The increase in working capital on the gas side is driven largely by rising prices for natural gas and, in turn, customer accounts receivable, storage gas and unbilled revenue. Similarly, electric customer accounts receivable and unbilled revenues are up. Also, on the electric side, storm deferrals have risen and inventories are higher. Materials and supplies have increased due to higher prices, longer procurement lead times and greater quantities needed to support a larger construction program and greater anticipated storm response requirements. Dollar throughput has nearly tripled in the last few years, and procurement lead times for some items have changed from a few weeks to several months. The price of copper has tripled in recent years and other heavily used metals, such as aluminum and high-quality steel used for transformer cores, have also experienced significant price increases. Global demand for raw materials, especially in the Asian countries (i.e., China, Korea, India), have put price pressures on an already tight supply.

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

A. Page 3.05 of Exhibit No. ___(KRK-3) 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 operations and maintenance ("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; and (5) direct labor.

III. CAUSES OF THE REVENUE DEFICIENCY

Q. Would you please describe the causes of the revenue deficiency?

A. Yes. To determine the major causes of the changes between two regulatory filings the Company uses a unit analysis. This analysis is simply the major categories of the income statement or ratebase that are determined for each of the regulatory periods, divided by the deliveries for that period. This calculation determines the major categories' unit cost for that particular period. The prior period that is used in this calculation has also been adjusted for the restating and pro forma adjustments that were allowed in the 2006 general rate case. The difference between the current period and prior period unit costs are then multiplied by deliveries for the current regulatory period. This product determines how much that major category has increased or decreased in cost since the last regulatory period taking into consideration load growth.

Exhibit No. ___(KRK-6) shows this calculation for the difference between the adjusted test period for this general rate filing, as determined in Exhibit No. ___(KRK-4) and the 2006 general rate case. Costs driving the current proposed increase include: increases of $7.0 million and $1.5 million in distribution operating expenses and customer accounting expenses, respectively, offset partially by a $5.4 million reduction in administrative and general expenses; increased depreciation and amortization expense of $18.9 million and $2.3 million, respectively, of which approximately $13.7 million is related to a new depreciation study which Richard Clarke discusses in his testimony; and a change in ratebase, that increases the revenue requirement by $20.5 million, of which approximately $5.0 million is related to the requested change in rate of return. A $4.2 million adjustment for Everett Delta, which I discuss later in my testimony, also contributes to the increase. Taxes and other make up the remainder of the difference.

IV. GAS PRO FORMA AND RESTATING ADJUSTMENTS

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

A. Exhibit No. ___(KRK-4) presents the impact of each of the gas pro forma and restating adjustments being made to the September 30, 2007 operating income statement and balance sheet. The first page of Exhibit No. ___(KRK-4), Summary page, presents the unadjusted operating income statement and Average-of-the-Monthly-Averages ratebase for the Company as of September 30, 2007 in the column labeled "Actual Results of Operation". The various line items are then adjusted for the summarized pro forma and restating adjustments, as shown in the column labeled "Adjusted Results of Operations". 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 remainder of Exhibit No. ___(KRK-4) is composed of two sections, described below.

Pages 4-A through 4-D of Exhibit No. ___(KRK-4) present a summary schedule of all the pro forma and restating adjustments. The first column of numbers, on page 4-A, is the unadjusted net operating income for the year ended September 30, 2007 and the unadjusted ratebase for the same period. Each column to the right of the first column represents a pro forma 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-D 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>Temperature Normalization</u>

This adjustment, as shown on Exhibit No. ___(KRK-4), page 4-A, column 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. Please see Ms. Janet Phelps' prefiled direct testimony, Exhibit No. __ (JKP-1T), for a discussion on the Company's methodology for temperature normalization.

This adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.01, decreases net operating income by $15,228,597.

4.02 Revenue and Purchased Gas Expenses

This restating and pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.02, restates sales revenues and purchased gas costs for rate changes during the test year to reflect the revenue that would have been collected and purchased gas costs that would have been incurred if the changes had been in effect during the entire test period. It also includes other necessary test year true up adjustments. Please refer to Ms. Phelps' prefiled testimony, Exhibit No. __ (JKP-1T), for a discussion of these adjustments.

This adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.02, increases net operating income by $16,941,026.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustments are:

4.03 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. The demand charge, including adjustments, has been and is currently being recovered through the Company's Purchased Gas Adjustment ("PGA") mechanism. Thus, to date, the revenue requirement related to the Everett Delta pipeline expansion has been eliminated for general ratemaking purposes.

It was contemplated that, at the end of the lease period, it would 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, in this proceeding, the Company is proposing to commence recovery of the Everett Delta pipeline expansion now in general rates instead of through the PGA mechanism and thereby eliminating the need for a future transition tariff. It is proposed that effective with the date new rates go into effect as a result of this proceeding, future Everett Delta lease payments from NWP be credited against the Everett Delta pipeline demand charge. Although this increases the revenue deficiency in this proceeding, the resulting general operating revenue increase will be offset by a reduction in the Company's PGA rates as a result of crediting the lease payment against the demand charge. New PGA rates are expected to go into effect on October 1, 2009 coincident or nearly coincident with new general rates going into effect as a result of this proceeding. The resulting impact on customers will be neutral.

This pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.03, decreases net operating income by $2,697,729.

4.04 <u>Federal Income Taxes</u>

This schedule adjusts actual Federal income tax expense to the restated level based on the test year for this case. As PSE's normal tax year ends December 31, this adjustment recalculates the test year using expenses and tax adjustments for the twelve months ended September 30, 2007.

The effect of this adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.04, is to increase net operating income by $378,373.

4.05 <u>Tax Benefit of Pro Forma Interest</u>

This pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-A, column 4.05, uses a ratebase method for calculating the tax benefit of pro forma 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 $7,156,868.

4.06 Depreciation and Amortization

This restating adjustment calculates the impact of implementing the depreciation study discussed in the prefiled direct testimony of Mr. Richard Clarke, Exhibit No. ___(CRC-1T). PSE hired Mr. Clarke and his firm, Gannett Fleming, Inc., to evaluate the Company's depreciation rates and provide an update to the current depreciation rates, which are based on a depreciation study as of December 31, 2000. Mr. Clarke also provides an explanation in his testimony of some of the major changes between the new depreciation rates and the current depreciation rates. The largest change in gas depreciation rates is attributable to the rate change on gas services. Excluding bare steel, services were previously considered to have a 40 year service life with 35% salvage and were being depreciated at a rate of 3.11 % of original cost. The new study indicates 75% net salvage is appropriate, moving the depreciation rate to 4.58%. This alone accounted for $8.1 million of the of the $13.7 million increase. The other large change in gas rates is attributable to the rate changes on computer equipment. This equipment was being depreciated at rates varying from 3.7% to 13.24%. The new study reduces the depreciable life of this equipment to five years and changes the accrual rate to 20%. This change increases gas depreciation expense by $4.2 million.

To adjust the test year depreciation expense to the new depreciation rates, we used the relationship of the new depreciation rate for each specific asset account to the old depreciation rate for the same account times the test year depreciation expense for that particular account. Mr. Story provides an example of how this was done, in his testimony and discussion of the electric depreciation adjustment, which was prepared the same way.

The results of this calculation are shown on lines 1-4 of this adjustment for gas plant and common plant allocated to gas. Lines 6 through 15 of this adjustment remove the impacts of Statement of Financial Accounting Standard 143, Accounting for Asset Retirement Obligations, which are not includable in rates.

On lines 21 and 22 the impact on current federal income tax and deferred taxes are presented. There is a shift between these two tax types because the higher book depreciation rates reduce currently payable taxes, but because tax depreciation does not change, deferred taxes are lower as the result of a normalizing entry.

On lines 27 and 28 ratebase is adjusted for the impact of the change in depreciation expense as it would impact accumulated depreciation and the change in deferred taxes on the balance sheet. The effect of all these adjustments is to decrease net operating income by $13,654,359 and decrease ratebase by $4,463,810.

/////

/////

/////

Q. In Docket No UG-060267, the Company's last general rate case, the Company proposed 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 or until otherwise decided by the Commission. Has the Company recorded the proper level of depreciation in accordance with its proposal?

A. Yes, depreciation for the Company's water heater and conversion burner rentals has been maintained at, or higher than, the test year level in the Company's 2006 general rate case subsequent to the order in that case. During the test year ended September 30, 2007, this amount was $8,594,247.

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

A. No, but as discussed above, the Company is proposing new depreciation rates for its gas and electric plant in service, including its rental water heater and conversion burner program. Accordingly, the Company is recommending in this proceeding that depreciation rates for rentals now be maintained at a minimum level of the $7,664,300 total restated amounts proposed, as a result of the new depreciation study, until the next general rate proceeding.

/////

/////

Q. Why are you making this recommendation?

A. Parties have expressed concerns in the past that because of the unusually high depreciation rates approved for rental equipment as the plant value declines customers could end up providing for greater recovery of depreciation expense than is being recorded. This is unlikely to occur because depreciation is recorded on the original cost, rather than net book value. Regardless, the Company does not object to continuing this practice, for the present.

Q. Why are rental depreciation rates unusually high?

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 recovering. Consequently, new and significantly higher rental depreciation rates were proposed and agreed upon.

Q. Did the Company raise rental rates to recover the higher depreciation?

A. Yes, because of the resulting rate spread and rate design implemented to begin recovering the new rates, a higher burden was placed on rental customers. However, because it would not have been appropriate to put the entire burden of rental depreciation issues related to prior years on current rental customers, and because there were also concerns that raising rental rates too far or fast would cause attrition in rental customers and reduced recovery of rental costs, only a portion, albeit significant, has been allocated to current rental customers. The remainder is being recovered in general rates.

Q. How does the new depreciation study affect rentals?

A. The new depreciation study confirms the appropriateness of the higher depreciation rates. With the new depreciation rates, rentals are still below parity. However, the rental program metrics are improving, and rentals are expected to come into parity on their own momentum with the new depreciation rate levels. Accordingly, we recommend that rentals receive no larger increase as a percentage than the highest increase in total proposed for other customers. The Company believes that its proposal in this case is an appropriate and reasonable measure to continue in working toward resolving this historic rental depreciation issue, now in its final stages. The Company expects that, by the next general rate proceeding, there will be enough historical evidence to allow the new depreciation rates to operate as designed, without any minimum provisions.

4.07 Pass Through Revenues and Expenses

This is a restating adjustment which removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as the conservation tracker, municipal taxes and the low income program. The associated expense for these direct pass through tariffs are also removed in this adjustment. The schedules for these revenues are not adjusted in a general rate case filing; therefore their impact on net operating income is being removed.

The net impact of this adjustment is to increase net operating income by $1,428,845.

4.08 <u>Bad Debts</u>

This restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years after removing the high and low years, which is the method used in PSE's 2006 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-B, column 4.08, decreases net operating income by $228,386.

4.09 Miscellaneous Operating Expense and Ratebase

This restating and pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.09, adjusts the test year for several different items.

1. Amortization of Deferred Taxes Regulatory Asset

This adjustment is intended to pro form out the amortization of a regulatory asset associated with the deferred taxes related to indirect overheads. The IRS changed the method of deduction for indirect overhead costs and required 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 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.

In accordance with the order, the Company is amortizing this deferral over a two year period, including the amortization of the carrying costs associated with the declining balance of the regulatory asset. This amortization will be completed during the course of this proceeding and this adjustment is to eliminate the test year amortization of $1,015,556, as there will be none during the rate year.

2. Service Contract Baseline Charges

Increase in Service Contract Baseline Charges – As discussed in the prefiled direct testimony of Ms. Susan McLain in Exhibit No. ___(SML-1CT), baseline charges on service contracts are expected to increase. This adjustment, which increases transmission expense by $6,661 and distribution expense by $442,344, represents the expected percentage increase over test year costs. These amounts may be trued-up for changes to contract price increases during the course of these proceedings as warranted.

3. FAS 106 Curtailment Gain

Adjustment of one-time FAS 106 Curtailment Gain – During the test period, a settlement was reached in which IBEW members elected to receive a lump sum payment in lieu of future post-retirement medical benefits. A one-time curtailment gain of $455,000 was recognized in relation to this settlement as a reduction to O&M expense. The $168,077 being removed from O&M in this adjustment represents the amount of the total curtailment gain that was booked to gas in the test period.

4. Summit Purchase Option Buyout

On September 14, 2007, the Company filed a petition with the Commission for an order that authorizes deferred accounting treatment related to the termination and extinguishment of a purchase option in the lease for PSE's corporate headquarters facilities in Bellevue. This pro forma adjustment is made to reflect the deferred accounting treatment being requested in that docket, No. UE-071876, (the "accounting petition"). The requested deferred accounting treatment is for the proceeds, net of incremental transaction costs, resulting from a Settlement Agreement to amend the PSE lease for its corporate headquarters buildings by terminating and removing the purchase option and by extending the existing lease terms in consideration of a $20 million (USD) payment to the Company by Summit REIT, Inc. The Company is requesting that the total deferred balance be amortized over seven years commencing January 1, 2008 and shaped in accordance with scheduled near-term contractual lease increases. The proceeds net of transaction costs are approximately $18.9 million. The adjustment shown on page 4.09, line 8, adjusts the test year rent expense for the Company's headquarters by the contractual annual rent increases between September 2007 and October 2009. This increase to lease expense is offset by the adjustment shown on line 10, which is made to represent the rate year amortization of the deferred payment, and is shaped to the scheduled rent increases being requested in the accounting petition. These two adjustments together decrease operating expenses by $260,021.

5. <u>Ratebase Adjustment</u>

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 increase net operating income by $428,022 and to increase ratebase by $2,458,688.

4.10 <u>Property Taxes</u>

This pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.10, reflects the estimated property tax levy rates to be paid in 2008 based upon 2007 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 $996,079.

4.11 <u>Excise Tax and Filing Fee</u>

This restating adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.11, 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 $304,305.

4.12 Director and Officer Insurance

This restating adjustment, shown on Exhibit No. ___(KRK-4), page 4-B, column 4.12, 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 total Puget Sound Energy, Inc. assets and applying that percentage to this insurance cost. This result is then compared to what was actually booked during the test year.

The effect of this adjustment is to reduce net operating income by $16,002.

4.13 Interest on Customer Deposits

This pro forma adjustment to operating income is the result of customer deposits being treated as a reduction to ratebase. This pro forma 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 4.13, reduces net operating income by $321,319.

4.14 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, which more accurately reflects the actual time frame that has been experienced between general rate case filings over the past several years. This same two year time frame was approved in the Company’s 2006 general rate case and is the time frame that is consistent with the Company’s anticipated timing of future rate case filings.

The average cost for a general case using this methodology is $2.95 million. This cost is allocated 50% to electric and 50% to natural gas which results in a $1.47 million dollar average cost for each energy group.

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 $43,996 as shown on Exhibit No. ___(KRK-4), page 4-C, column 4.14.

4.15 Deferred Gains/Losses on Property Sales

The purpose of this restating and pro forma 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 4.15, decreases net operating income by $142,791.

4.16 Property and Liability Insurance

This pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.16, reflects the actual and 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 $115,718.

4.17 <u>Pension Plan</u>

This restating adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.17, adjusts the test year to reflect cash contributions to the Company's qualified retirement fund. As the Company has not needed to make any tax deductible cash contribution, as determined by its plan actuary, the cost of the pension plan is determined to be zero for the test period.

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 increase net operating income by $265,753.

4.18 <u>Wage Increase</u>

This pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-C, column 4.18, reflects the impact of wage increases and payroll tax changes, as described in the prefiled direct testimony of Mr. Tom Hunt, Exhibit No. ___(TMH-1T). For represented (union) employees, the adjustment annualizes the wage increases granted in 2007, 2008, and 2009. The percentage of wage increase for IBEW union employees from the test period through the rate year are 3.5% effective June 20, 2007, 3.25% effective April 1, 2008, and 3.25% effective April 1, 2009. The percentage of wage increase for UA union employees from the test period through the rate year are 3.11% effective October 1, 2007, 2.85% effective October 1, 2008, and 2.84% effective October 1, 2009. The 2007, 2008 and 2009 increases for both IBEW and UA are contractual. Corrected UA wage increases are shown in the prefiled direct testimony of Mr. Tom Hunt, Exhibit No. ___ (TMH-1T). The revenue requirement will be updated later in this proceeding to reflect the corrections. The percentage of wage increase for non-union employees from the test period through the rate year are 1.10% effective January 1, 2007, 3.02% effective March 1, 2007, 0.24% effective July 2, 2007, 3.5% effective March 1, 2008, and 3.5% effective March 1, 2009. These 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 pro forma adjustment reflecting the impact of wage increases and payroll tax changes for both management (non-union) and represented (union) employees, as discussed above, decreases net operating income by $1,443,449.

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 plus two separate adjustments in 2007. March 1st is normally 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 plus the two additional adjustment months in 2007 and, in turn, the change in the average annual salary between years. For the years 2004 through 2007, this change was 1.05%, 1.87%, 2.95% and 2.44%, respectively, or 2.14% on average. This was compared to the average wage increase allowed for management employees during those same years of 2.98%, 3.04%, 2.73% and 4.40%, respectively, or 3.45% on average. The 2.14% average change between the beginning and end of each adjustment year is 61.97% of the 3.45% average increase at the beginning of each year. This percentage then is applied to the expected compound wage increase of 7.72% from the end of the test year through the rate year ending October 31, 2009, to yield a 4.79% wage adjustment for management employees after taking slippage into consideration.

4.19 **Investment Plan**

This pro forma adjustment, shown on Exhibit No. ___(KRK-4), page 4-D, column 4.19, 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 $61,108 as the result of this adjustment.

4.20 **Employee Insurance**

This pro forma 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 $842 and $843, respectively, per UA and IBEW eligible employee per month in 2008 and $910 each per eligible employee per month in 2009. The amounts are the result of negotiations between PSE and the UA union and PSE and the IBEW 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 55.72%.

The effect of this adjustment, shown on Exhibit No. ___(KRK-4), page 4-D, column 4.20, is to decrease net operating income by $577,422.

4.21 Incentive Compensation

In his prefiled direct 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 2004 through 2007 and allocated the four-year average to electric and natural gas based on payroll distribution. The year 2007 is the current incentive amount estimated to be paid and will be trued up to actual during the course of this proceeding.

The incentive is then allocated to O&M and other accounts based on where payroll was charged during the test year. This amount is then compared to actual expenses during the test year and results in a decrease in net operating income of $288,202, as shown on Exhibit No. ___(KRK-4), page 4-D, column 4.21.

/////

/////

/////

/////

V. CALCULATION OF THE REVENUE DEFICIENCY

A Revenue Deficiency Based on the Pro Forma and Restated Test Period

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

A. Exhibit No. ___(KRK-5) presents the calculation of the revenue deficiency based on the pro forma and restated test period. The different pages in Exhibit No. ___(KRK-5) are:

5.01 General Rate Increase

This schedule, shown on Exhibit No. ___(KRK-5), page 5.01, shows the test period pro forma and restated ratebase, line 1, and net operating income, line 6. Based on $1,349,395,044 invested in ratebase, an 8.60% rate of return and $80,738,731 of net operating income the Company would have a revenue deficiency of $56,770,922.

5.02 Cost of Capital

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 prefiled direct testimony of Mr. Donald E. Gaines, Exhibit No. ___(DEG-1T). The rate of return is 8.60% and 7.29% net of tax.

5.03 Conversion Factor

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 62.19600%.

B. Wholesale Market Hedging Activities

Q. Please explain the revision the Company made to its PGA Mechanism related to the Company's hedging program.

A. As discussed in the prefiled direct testimony of Mr. Donald Gaines, Exhibit No. ___(DEG-1T), the Company has opened a new line of credit that is dedicated to supporting the Company's wholesale market hedging activities. The Commission approved the Company's proposal, made in the 2006 general rate case, to pass through to customers, via the PGA Mechanism, the costs associated with such a credit facility that are used to support transactions for the core gas portfolio. As proposed in that case, the Company is tracking the set up fees and any interest costs in separate accounts from other bank fees and interest payments so that the costs are easily identifiable and can be audited for reasonableness.

/////

Q. How was this change implemented?

A. The Company modified its PGA Mechanism tariff schedule, Rule No. 26, to effect the change.

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

A. No. That portion of the costs associated with the new credit facility core gas portfolios are being charged to customers through the PGA and have no impact on the revenue requirement in this proceeding.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.