

**EXHIBIT NO. ___(SEF-1T)
DOCKETS UE-17___/UG-17___
2017 PSE GENERAL RATE CASE
WITNESS: SUSAN E. FREE**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

Docket UE-17___

Docket UG-17___

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

SUSAN E. FREE

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 13, 2017

PUGET SOUND ENERGY

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
SUSAN E. FREE**

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1 **PUGET SOUND ENERGY**

2 **PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**
3 **SUSAN E. FREE**

4 **I. INTRODUCTION**

5 **Q. Please state your name and business address.**

6 A. My name is Susan E. Free, and my business address is 10885 N.E. Fourth Street,
7 Bellevue, Washington 98004. I am employed by Puget Sound Energy (“PSE”) as
8 the Manager of Revenue Requirement.

9 **Q. Have you prepared an exhibit describing your education, relevant**
10 **employment experience, and other professional qualifications?**

11 A. Yes. It is the First Exhibit to my Prefiled Direct Testimony, Exhibit No. ____ (SEF-
12 2).

13 **Q. Please summarize the purpose of your testimony.**

14 A. My testimony and exhibits in this proceeding will address the results of operations
15 and the associated base rates revenue deficiency for gas operations.

16 **Q. Are you sponsoring any exhibits?**

17 A. Yes, I am sponsoring Exhibit No. ____ (SEF-3) through Exhibit No. ____ (SEF-7).

1 certain of the schedules will be filed at the same time as the compliance filing in
2 this case. The following is a summary of how PSE proposes to change its base
3 and adjusting rate schedules in this proceeding or at the time of compliance:

- 4 • Base rates will be increased for the difference between the
5 revenue requirement in the 2011 general rate case and the
6 revenue requirement in this proceeding.
- 7 • Schedule 141 will be set to zero.
- 8 • Schedule 142 will be lowered to remove the portion that is
9 recovering the K-factors that increased PSE's rates during
10 the stay-out period.
- 11 • Schedule 149 will be lowered to transfer the revenue
12 requirement associated with the portion of CRM
13 investment that was approved in PSE's most recent CRM
14 filing under UG-160791. I will discuss this in more detail
15 later in my testimony where I discuss PSE's approach for
16 conforming in principle with the Commission policy
17 statement in UG-120715.

18 **Q. Does your testimony cover the changes to all of the base and adjusting rate**
19 **schedules listed above?**

20 A. No. My testimony will focus only on determining PSE's natural gas revenue
21 requirement. I will discuss the amount that base rates are deficient (as opposed to
22 the overall rate change) based on this revenue requirement. The Prefiled Direct
23 Testimony of Jon A. Piliaris, Exhibit No. ___(JAP-1T), will cover the overall rate
24 change, and will discuss the change to base rates as well as the other natural gas
25 rate schedules discussed above.

1 **III. REVENUE REQUIREMENTS**

2 **A. Exhibit No. ____ (SEF-3) Base Rates Revenue Requirement Deficiency**

3 **Q. Would you please explain Exhibit No. ____ (SEF-3)?**

4 A. Exhibit No. ____ (SEF-3) presents the calculation of the natural gas base rates
5 revenue deficiency based on the pro forma and restated test period. It also shows
6 the requested cost of capital and the natural gas conversion factor. The following
7 are descriptions of the individual pages in Exhibit No. ____ (SEF-3).

8 **Natural Gas Base Rates Revenue Requirement Deficiency**

9 The natural gas base rates revenue requirement deficiency is shown on page one
10 of Exhibit No. ____ (SEF-3). This page shows the test period pro forma and
11 restated rate base, line 1; rate of return, line 2; operating income requirement,
12 line 4; pro forma operating income, line 6; and base rates revenue requirement
13 deficiency, line 10.

14 Based on \$ \$1,760,693,633 invested in rate base, a 7.74% rate of return and
15 \$122,011,947 of pro forma operating income, PSE has a base rates revenue
16 requirement deficiency for natural gas revenues of \$22,992,570.

17 **Cost of Capital Electric and Gas**

18 Page 2 of Exhibit No. ____ (SEF-3) reflects the proposed capital structure for PSE
19 during the rate year and the associated costs for each capital category. The capital
20 structure and costs are presented in the Prefiled Direct Testimony of Brandon
21 Lohse, Exhibit No. ____ (BJL-1T). The rate of return is 7.74 percent and 6.69

1 percent net of tax. Please see the Prefiled Direct Testimony of Brandon Lohse,
2 Exhibit No. ____ (BJL-1T), for a discussion of the components of the cost of debt,
3 including the addition of costs of the facility supporting energy hedging which
4 was previously included in PSE's Power Cost Adjustment ("PCA") mechanism
5 and is currently included in PSE's Purchased Gas Adjustment ("PGA")
6 mechanism. These costs have been included in PSE's cost of capital as they will
7 no longer be tracked in PSE's PCA mechanism pursuant to the settlement
8 agreement approved in Order No. 11 in Docket UE-130617. Additionally, in
9 PSE's next PGA filing for rates effective November 1, 2017, PSE will only
10 include two months of recovery of these costs as they will be included in PSE's
11 overall cost of capital from this proceeding.

12 **Natural Gas Conversion Factor**

13 Page three of Exhibit No. ____ (SEF-3) provides the natural gas conversion factor
14 that is used to adjust the natural gas base rates net operating income deficiency for
15 revenue sensitive items and federal income tax to determine the total natural gas
16 base rates revenue deficiency. The revenue sensitive items are the Washington
17 State utility tax, Washington Utilities and Transportation Commission annual
18 filing fee, and bad debts. The conversion factor used in the revenue requirement
19 calculation is 0.620450 for natural gas operations.

1 **B. Exhibit No. ____ (SEF-4) Gas Summary**

2 **Q. Would you please explain Exhibit No. ____ (SEF-4)?**

3 A. Exhibit No. ____ (SEF-4) presents the impact of each of the natural gas pro forma
4 and restating adjustments being made to the September 30, 2016 operating
5 income statement and rate base. The first page of Exhibit No. ____ (SEF-4),
6 Summary page, presents the unadjusted gas operating income statement and
7 average of the monthly-averages (“AMA”) rate base for PSE as of September 30,
8 2016 in the column labeled “Actual Results of Operation”. The various line items
9 are then adjusted for the summarized pro forma and restating adjustments, as
10 shown in the column labeled “Adjusted Results of Operations”. This column is
11 the source used to calculate the base rates revenue deficiency. In the second to last
12 column the base rates revenue deficiency is added to the adjusted income
13 statement, and the impact on the operating income and rate base is presented in
14 the final column. The remainder of Exhibit No. ____ (SEF-4) is described below.
15 Pages two through four of Exhibit No. ____ (SEF-4) present a summary schedule of
16 all the natural gas pro forma and restating adjustments. The first column of
17 numbers on page two is the unadjusted net operating income for the year ended
18 September 30, 2016 and the unadjusted rate base for the same period. Each
19 column to the right of the first column represents a pro forma and/or a restating
20 adjustment to net operating income or rate base. Each of these adjustments has a
21 supporting schedule, which is referenced by the page number shown in each
22 column title.

1 **C. Exhibit No. ____ (SEF-5) Natural Gas Test Year Data**

2 **Q. Would you please explain Exhibits No. ____ (SEF-5)?**

3 A. Exhibit No. ____ (SEF-5) presents the actual financial statements for the test year
4 as follows.

5 Income Statements

6 Page one of Exhibit No. ____ (SEF-5) presents the unadjusted natural gas income
7 statement for the twelve months ending September 30, 2016 the test year for this
8 general rate case filing.

9 Balance Sheets

10 Pages two through five of Exhibit No. ____ (SEF-5) present the combined end of
11 period and AMA balance sheets for the test year.

12 Rate Base

13 Page six of Exhibit No. ____ (SEF-5) presents the test year AMA rate base
14 calculations.

15 Working Capital

16 Pages seven through nine of Exhibit No. ____ (SEF-5) present the test year working
17 capital calculation that is included as part of the rate base calculation.

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Allocation Factors

Page ten of Exhibit No. ____ (SEF-5) presents the allocation methods and factors used in allocating common expenditures between electric and natural gas operations.

Q. Please describe the allocation methods used on page ten of Exhibit No. ____ (SEF-5).

A. Page ten of Exhibit No. ____ (SEF-5) 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 natural gas service, to customers. Common plant includes costs associated with land, structures, and equipment, which are not charged specifically to electric or gas operations. PSE allocates its common utility plant for electric and gas by using the four-factor allocation method.

Common operating costs are those costs that are incurred on behalf of both electricity and natural gas customers. PSE incurs common costs related to: customer accounts expenses, customer service expenses, administrative and general expense, depreciation/amortization, other operating expense and taxes other than federal income tax. These common costs are allocated to electric and natural gas using the most appropriate allocation method for the type of cost being allocated. Allocation methods used include: (1) twelve month customer average,

1 (2) joint meter reading customers, (3) non-production plant, (4) four factor
2 allocator, and (5) direct labor.

3 **Q. Are rate base and working capital calculated in the same manner as allowed**
4 **in the last general rate case?**

5 A. Yes, they have been calculated consistent with the manner approved in the 2011
6 general rate case.

7 **Q. Please explain the combined working capital calculation.**

8 A. Pages seven through nine of Exhibit No. ___(SEF-5) present the working capital
9 calculation. Working capital is the measure, for ratemaking purposes, of investor
10 funding of daily operating expenditures and a variety of non-plant investments
11 that are necessary to sustain ongoing operations in order to bridge the gap
12 between the time expenditures for services are required to be provided and the
13 time cost recovery occurs. The purpose of this calculation is to provide a return on
14 the funds the shareholders have invested in PSE for utility purposes that have not
15 been accounted for elsewhere or that are not otherwise already earning a rate of
16 return. The calculation is based on the average of the monthly averages of the
17 actual amounts in the asset and liability accounts for these items during the test
18 year.

1 **IV. INDIVIDUAL ADJUSTMENTS**

2 **A. Exhibit No. (SEF-6) Common Adjustments**

3 **Q. Please explain the adjustments that are common to electric and gas**
 4 **operations.**

5 A. Exhibit No. ____ (SEF-6) presents the common adjustments that apply to both
 6 natural gas and electric operations. Each of the individual adjustments will be
 7 addressed in testimony as indicated below.

8 **Table 1. Assignments of Common Adjustments**

Adjustment	Katherine J. Barnard Exhibit No. (KJB-1T)	Susan E. Free Exhibit No. (SEF-1T)	Adjustment	Katherine J. Barnard Exhibit No. (KJB-1T)	Susan E. Free Exhibit No. (SEF-1T)
6.01 Revenue and Expenses	X	X	6.12 Rate Case Expenses	X	
6.02 Temperature Normalization	X	X	6.13 Deferred Gain/Loss on Property Sales		X
6.03 Pass Through Revenue and Expense	X	X	6.14 Property & Liability Insurance		X
6.04 Federal Tax	X	X	6.15 Pension Plan		X
6.05 Tax Benefit of Pro forma Interest		X	6.16 Wage Increase		X
6.06 Depreciation Expense	X		6.17 Investment Plan		X
6.07 Normalize Injuries and Damages		X	6.18 Employee Insurance		X
6.08 Bad Debt	X		6.19 Environmental Remediation		X
6.09 Incentive Pay		X	6.20 Payment Processing Costs	X	
6.10 D&O Insurance		X	6.21 South King Service Center		X
6.11 Interest on Customer Deposits		X	6.22 Excise Tax & Filing Fee		X

1 An explanation of each of the common adjustments that I will address is listed
2 below:

3 **Adjustment No. 6.01G Revenues and Expenses**

4 This is a pro forma and restating adjustment which makes the following
5 adjustments to the test year income statement:

- 6 • Modifies the test year revenues to the revenues that would have
7 been collected during the test year if only the base rates from the
8 2011 general rate case had been in effect for the whole test year.
9 As discussed in more detail above, my testimony focuses on
10 determining and describing only the change in the revenue
11 requirement related to base rates. The Prefiled Direct Testimony of
12 Jon A. Piliaris, Exhibit No. ___(JAP-1T), covers the change to the
13 other rate schedules which include Schedule 141 Expedited Rate
14 Filing, Schedule 142 Decoupling and K-Factor, and Schedule 149
15 Gas Cost Recovery Mechanism.

- 16 • The following steps were taken to reflect the revenue in the test
17 year at 2011 general rate case levels.
 - 18 ▪ Removed the decoupling deferrals and amortization to reflect the
19 test year revenue on a volumetric basis (Lines 13 and 14).

 - 20 ▪ Removed the non-tracker/rider non-base rates revenue from the
21 test year (Lines 2 through 3 and 10 through 11). Additional non-
22 tracker/rider non-base rates revenue for gas Schedule 149 Cost
23 Recovery Mechanism is removed in Adjustment 7.01 which is
24 discussed in more detail later in my testimony.

 - 25 ▪ The first two steps result in the test year revenue being reflected on
26 a volumetric basis priced at 2011 general rate case base rates.
27 Therefore, the final step is to weather normalize these revenues
28 which is performed in Adjustment 6.02, discussed below.

- 29 • This adjustment also removes the credits passed back to customers
30 associated with Schedule 132 Merger Rate Credit, which is
31 reflected on lines 6 and 16.

- 32 • Line 12 removes the accruals and true-ups recognized in the test
33 year for the estimated 2014 and 2015 earnings sharing.

- 1 • Lines 4 and 22 annualize the Schedule 101 revenue and associated
2 gas costs based on the amounts approved in PSE’s 2015 and 2016
3 Purchased Gas Adjustment filings.
- 4 • Finally, other miscellaneous adjustments to revenue and to gas
5 costs as supported by Mr. Jon Piliaris are included on Lines 5, 15,
6 23 and 24.

7 Overall, Adjustment 6.01 decreases net operating income for natural gas
8 operations by \$32,674,131.

9 **Adjustment No. 6.02G Temperature Normalization**

10 As I discussed above, due to Adjustment 6.01, revenues have been reflected on a
11 volumetric basis at 2011 general rate case base rate levels for the test year.

12 Therefore, the temperature normalization adjustment is necessary to restate the
13 test year delivered load and revenue to a level which would have been expected to
14 occur had the temperatures during the test year been “normal”. The gas
15 adjustment represents the difference between actual and normalized therms.

16 The test year was warmer than normal requiring an adjustment to net operating
17 income to bring revenues up to what would have occurred under normal
18 conditions. The natural gas load adjustment increases actual therms by 83,004,481
19 therms. The Prefiled Direct Testimony of Dr. Chun K. Chang, Exhibit
20 No. ___(CKC-1T) discusses PSE’s weather normalization methodology, the
21 pricing of the load adjustments, and their allocation to the rate classes based on
22 the proposed rate class level weather normalization methodology. Additionally,
23 the gas adjustment adjusts the purchased gas costs for the change to the PGA
24 revenues.

1 This adjustment increases net operating income for natural gas operations by
2 \$16,069,959.

3 **Adjustment No. 6.03G Pass-through Revenue and Expense**

4 This restating adjustment removes from operating revenues all rate schedules that
5 are a direct pass through of specifically identified costs or credits to customers,
6 such as the conservation rider, municipal and property taxes, and the low income
7 rider. The associated expense that is recorded in the test year for these direct pass
8 through tariffs is also removed in this adjustment. Additionally, Schedule 106
9 revenue and amortization associated with recovery or pass-back of previous PGA
10 deferrals are removed for natural gas operations.

11 The net impact of this adjustment increased net operating income for natural gas
12 by \$736,148.

13 **Adjustment No. 6.04G Federal Income Tax**

14 This adjustment restates the test year for the appropriate level of federal income
15 tax ("FIT") expense for this case. The impact of this restating adjustment is shown
16 on Exhibit No. ___(SEF-6), page 6.04 and increases net operating income for gas
17 by \$700,822.

18 **Adjustment Nos. 6.05E&G Tax Benefit of Pro Forma Interest**

19 As in prior rate filings, PSE has included an adjustment to capture the tax benefit
20 of pro forma interest for electric and gas operations, which in the test year is all
21 recognized below the line. This adjustment recognizes the tax deduction related to

1 the level of interest associated with the restated and pro forma rate base utilizing
2 the new capital structure and interest rate adopted in this rate filing. The
3 adjustment for the tax benefit of pro forma interest on electric operations
4 increases net operating income by \$53,350,177 and on gas operations increases
5 net operating income by \$18,425,659.

6 **Adjustment No. 6.06G Depreciation Study**

7 This restating adjustment calculates the impact of implementing the depreciation
8 study discussed in the Prefiled Direct Testimony of John J. Spanos, Exhibit
9 No. ____ (JJS-1T). Please refer to the Prefiled Direct Testimony of Katherine J.
10 Barnard, Exhibit No. ____ (KJB-1T), for a detailed discussion of this adjustment.

11 The result of the restating adjustment, which impacts depreciation expense,
12 federal income tax expense, accumulated depreciation and accumulated deferred
13 income taxes, increases net operating income by \$13,174,098 and increases rate
14 base by \$6,587,049 for natural gas operations.

15 **Adjustment Nos. 6.07E&G Injuries and Damages**

16 This restating adjustment is prepared in accordance with the 2009 general rate
17 case order in Dockets UE-090704 and UG-090705. This adjustment restates
18 injuries and damages by adjusting actual test year accruals and payments of
19 injuries and damages to the three-year average of the most recent accruals and
20 payments. This adjustment increases net operating income for electric operations
21 by \$69,387 and decreases net operating income for natural gas operations by
22 \$57,738.

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Adjustment No. 6.08G Bad Debt

This restating adjustment calculates the appropriate bad debt rate to apply to natural gas operations. Please refer to the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ____ (KJB-1T), for a detailed discussion of this adjustment. This adjustment decreases net operating income for natural gas operations by \$158,835.

Adjustment Nos. 6.09E&G Incentive Pay

This restating adjustment uses a four-year average of incentive compensation paid to employees, which is allocated between electric and natural gas operations. The Prefiled Direct Testimony of Thomas M. Hunt, Exhibit No. ____ (TMH-1T) explains why this expense is appropriate for ratemaking consideration and how the program is similar to previously allowed incentive compensation programs. In this proceeding PSE is including officers’ pay as part of the four-year average, consistent with treatment before PSE’s 2009 general rate. In both the 2009 and 2011 general rate cases, while requesting no precedent be set, PSE refrained from seeking recovery of officers’ incentive payouts due to the then-current economic situation.

For this calculation, PSE used the payouts which occurred in March for years 2013 through 2016, which related to calendar years 2012 through 2015. Since the March 2017 payout will not be finalized by the time this case is filed, the time period used to calculate the average will be updated to include the March 2017 payout for the 2016 calendar year in PSE’s supplemental filing once the 2017

1 payout amount is known and measurable. The incentive payment is allocated to
2 operations and maintenance (“O&M”) based on the distribution of wages during
3 the test year. The four-year average of the payouts is allocated between electric
4 and natural gas O&M using the direct labor allocator.

5 This adjustment increases net operating income for electric operations by
6 \$157,551 and for natural gas operations by \$213,058.

7 **Adjustment Nos. 6.10E&G Directors and Officers (“D&O”) Insurance**

8 This restating adjustment removes the portion of D&O insurance that should be
9 allocated to non-utility activity. This adjustment also annualizes the most current
10 premiums, which became effective during the test year for the Directors and
11 Officers insurance.

12 In the restated amount, premiums are first annualized to reflect the most current
13 insurance rates in the test year since insurance premiums become effective each
14 May. The total annualized amount is then allocated to O&M in the same manner
15 as the test year D&O insurance, which is based on where direct labor is charged.

16 To allocate the restated insurance expense between utility and non-utility activity,
17 PSE uses an allocation methodology evenly weighted between the 1) allocation of
18 directors’ fees and 2) allocation of covered employees’ salaries. The restated
19 D&O insurance applicable to O&M is then allocated between electric and gas
20 operations based on the average number of customers allocator.

21 This adjustment increases net operating income for electric operations by \$16,141
22 and for natural gas operations by \$11,636.

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Adjustment Nos. 6.11E&G Interest on Customer Deposits

This restating adjustment reflects the impact of interest associated with using customer deposits as a reduction to rate base. Since this interest is originally recorded below the line in the test period, this restated adjustment adds to operating expense the cost of interest for this item based on the most currently implemented annual interest rate, which for 2016 is 0.49%. Pursuant to WAC 480-100-113(9), the interest rate paid on customer deposits is determined annually based on the interest rate for a one year Treasury Constant Maturity as of the fifteenth day of January of that year. This approach is consistent with prior general rate cases. This adjustment will be updated during the course of this proceeding for the interest rate that will become effective in January 2017. The impact of this restating adjustment decreases net operating income for electric operations by \$108,171 and for natural gas operations by \$30,709.

Adjustment No. 6.12G Rate Case Expenses

This restating adjustment replaces test year rate case expense with a normalized level for rate recovery. Please refer to the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for a detailed discussion of this adjustment. The result of this natural gas restating adjustment decreases net operating income by \$280,617.

Adjustment Nos. 6.13E&G Deferred Gains and Losses on Property Sales

The purpose of this restating and pro forma adjustment is to provide customers with the gains and losses from sales of utility real property completed since the

1 last general rate case. The gains and losses are allocated between gas and electric
2 based on the use of the property and amortized over three years with the deferred
3 balance included in working capital. This adjustment is done in compliance with
4 the settlement agreement for property sales from Docket UE-89-2688-T. The
5 deferred gains and losses approved in the 2011 general rate case were each over-
6 amortized due to their three-year amortization periods being shorter than PSE's
7 recent stay-out period. These over-amortized balances were used to offset the new
8 deferred gains and losses being requested for recovery in this proceeding.

9 This adjustment increases net operating income for electric operations by
10 \$171,200 and decreases net operating income for natural gas operations by
11 \$105,090.

12 **Adjustment Nos. 6.14E&G Property and Liability Insurance**

13 This pro forma adjustment reflects the actual premium increases for property and
14 liability insurance expense based on premiums currently in place. Updates will be
15 made to policies that will have new premiums during the course of the
16 proceeding. Common property and liability insurance is allocated to electric and
17 natural gas operations based on the non-production plant or number of customers'
18 allocation factor. This adjustment increases net operating income for electric
19 operations by \$66,147 and for natural gas operations by \$45,174.

20 **Adjustment Nos. 6.15E&G Pension Plan**

21 This restating adjustment calculates pension expense based on a four-year average
22 of cash contributions to PSE's qualified retirement fund.

1 In the 2009 general rate case, the Commission affirmed that the actual four-year
2 average of cash contributions ending with the historical test year should be used
3 for setting rates. Using cash contributions instead of expenses recognized under
4 the Financial Accounting Standards Board Accounting Standards Codifications
5 allows for consistency when applying this adjustment.

6 As determined by the plan actuary, PSE made tax deductible cash contributions
7 totaling \$86.1 million for the four-year period ending September 30, 2016. The
8 four-year average of \$21.5 million is allocated to O&M based on the distribution
9 of wages and then allocated between electric and natural gas based on the direct
10 labor allocator.

11 This adjustment decreases net operating income for electric operations by
12 \$1,184,945 and for natural gas operations by \$572,091.

13 **Adjustment Nos. 6.16E&G Wage Increase**

14 This pro forma adjustment pro forms the impact of wage increases and payroll tax
15 changes, as described in the Prefiled Direct Testimony of Thomas M. Hunt,
16 Exhibit No. ____ (TMH-1T). For represented (union) employees, the adjustment
17 reflects the known annual wage increases that were granted in the approved
18 contracts for the International Brotherhood of Electrical Workers (“IBEW”) and
19 United Association of Plumbers and Pipefitters (“UA”) union employees. Since
20 the contract for IBEW-represented employees runs from December 11, 2014
21 through March 31, 2017, PSE will include the new contracted IBEW wage
22 increase as soon as the new contract is in place if known during the course of this

1 proceeding. The contracted wage increase percentage for IBEW union employees
2 is 6 percent through December 31, 2015, which is fully included in the test year;
3 and 2.75 percent effective January 1, 2016. This results in a compounded wage
4 increase over the test year level for IBEW of 0.69 percent for IBEW-represented
5 employees.

6 The contracted wage increases for UA union employees was three percent
7 effective October 1, 2016. This results in a compounded wage increase over the
8 test year level of three percent. PSE will include the new contracted UA wage
9 increase if it becomes known during the course of this proceeding.

10 The average wage increase used in the wage adjustment for non-union employees
11 includes the known wage increase of 2.91 percent that was paid effective March
12 1, 2016 plus an estimated three percent increase effective March 1, 2017. This
13 results in a compounded wage increase over the test year levels of 4.25 percent
14 for non-union employees. PSE will update the actual wage increase for March 1,
15 2017 once it becomes known during the course of this proceeding. As in prior rate
16 cases, this increase has been weighted by prior year actual salary increases. This
17 is done to account for “slippage,” as it is sometimes called, that occurs when new
18 non-union employees are hired at lower salary rates than the more senior
19 employees they are replacing.

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

3 A. Slippage is determined by measuring the difference between the average wage
4 increase granted during the last four periods and the change between the average
5 wage at the beginning and end of each of the same periods. Projected wage
6 increases for the employees are then weighted, or reduced, by the slippage
7 differential.

8 In order to perform the actual slippage calculation in this case, PSE first obtained
9 the annualized payroll for all non-union employees as of March 1st for each of the
10 last five years, which is the effective date of annual non-union salary adjustments.
11 From this, PSE determined the average annual salary per non-union employee and
12 calculated the actual percent increase for the years 2014 to 2017, and compared
13 this to the projected percent wage increase for non-union employees. Average
14 salary change per non-union employees as of March 1st for the years 2014 through
15 2017 was 3.61%, 2.91%, .49% and 2.27% respectively, or 2.40% on average
16 when compounded. This was compared to the average wage increase granted for
17 non-union employees during those same years of 2.87%, 2.86%, 2.91% and 3%
18 respectively, or 3.04% on average when compounded. The 2.40% average change
19 in wages between the beginning and end of each year is 78.78% of the 3.04%
20 average wage increase given at the beginning of each year. This slippage
21 percentage is applied to the 4.25% compound wage increase for March 31, 2017
22 to yield an effective wage increase of 3.35% that is used for non-union
23 employees. As amounts for March 2017 used in the slippage calculation represent

1 estimates, they will be updated to actual amounts during the course of this
2 proceeding.

3 **Q. What payroll taxes are included in the adjustment?**

4 A. The payroll taxes included in the adjustment are Social Security (Federal
5 Insurance Contribution Act or “FICA”), Medicare, Federal Unemployment Tax
6 (“FUTA”) and State Unemployment Tax (“SUTA”).

7 **Q. How are the payroll taxes for the wage adjustment calculated?**

8 A. The Medicare Tax applies the actual percent tax rate to the wage increase. FICA,
9 FUTA and SUTA tax calculations include wage limits where the payroll taxes are
10 only calculated up to the wage limit of the employee. Accordingly, the payroll tax
11 on FICA, FUTA and SUTA in this adjustment are calculated by employee to test
12 for the wage limits.

13 **Q. What is the overall impact of the wage adjustment on net operating income?**

14 A. This adjustment decreases net operating income for electric operations by
15 \$1,497,038 and for natural gas operations by \$972,167.

16 **Q. Would you please continue discussing the common adjustments?**

17 A. Yes. The next common adjustment is:

18 **Adjustment Nos. 6.17E&G Investment Plan**

19 This pro forma adjustment adjusts the PSE portion of investment plan expense to
20 reflect the additional expense associated with the wage increases and is based on

1 the current employee contribution rates. This adjustment decreases net operating
2 income for electric operations by \$106,542 and for natural gas operations by
3 \$51,438.

4 **Adjustment Nos. 6.18E&G Employee Insurance**

5 Please see the Prefiled Direct Testimony of Mr. Thomas M. Hunt, Exhibit
6 No. ___(TMH-1T), for a detailed description of PSE's employee benefits. This
7 pro forma adjustment adjusts the test year employee benefits expense—including
8 employee insurance, Long Term Disability, Basic Life Insurance and Wellness
9 Credits—to the most current average cost per participant. As these costs are
10 subject to change, PSE will be updating these costs during the course of this
11 proceeding.

12 These costs are allocated to O&M based on the distribution of wages during the
13 test year and then to electric and natural gas based on the direct labor allocator.

14 The effect of this adjustment is to decrease net operating income for electric
15 operations by \$121,751 and for natural gas operations by \$58,781.

16 **Adjustment Nos. 6.19E&G Environmental Remediation**

17 PSE has had deferred accounting for its environmental remediation costs and
18 recoveries since the early 1990s. Details of PSE's environmental remediation
19 requirements and efforts are provided in the Prefiled Direct Testimony of John K.
20 Rork, Exhibit No. ___(JKR-1T).

1 Paragraph 6 (e) in Final Order No. 01 in Docket No. UE-070724 (“Environmental
2 Order”) states:

3 Allowed net deferred costs will be amortized over a five year
4 period on the date all costs, net of recoveries, become known and
5 declared prudent. The deferrals will be consistent with the
6 Commission’s Merger Order in Docket UE-960195.

7 One result of Docket UE-070724 was to bring the treatment of environmental
8 deferrals in alignment for electric and gas. The gas environmental treatment was
9 approved in Docket UG-920781.

10 As stated by Mr. Rork, the potential for future recoveries from insurance policies
11 has declined in relation to amounts previously recovered. Additionally, as
12 discussed by Mr. Rork, although there are still some viable third-party claims that
13 remain, PSE believes it has substantially exhausted known third-party claims for
14 remediation sites. Accordingly, PSE is requesting recovery of certain of its net
15 deferred environmental costs.

16 To be consistent with the intent of the Environmental Order, remediation deferrals
17 for gas and electric are treated similarly.¹ The amount of deferred net costs PSE is
18 seeking for recovery in this case has been determined as follows:

- 19 1. Only actual costs are being requested for recovery. In this
20 direct filing, PSE is including actual costs through
21 September 30, 2016. These costs will be updated to more
22 current amounts during the course of this proceeding.

¹ *In re Petition of PSE For An Accounting Order Regarding the Accounting Treatment for Costs of its Electric Environmental Remediation Program*, Docket UE-070724, Order 01, ¶ 5 (October 8, 2008).

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- 2. In order to maintain insurance and third-party recoveries to offset future remediation costs on existing environmental sites, PSE is proposing to include only a portion of the unassigned insurance and third party recoveries to offset the actual costs included in this proceeding.
 - a. The Prefiled Direct Testimony of John K. Rork, Exhibit No. ___(JKR-1T), explains that insurance and third-party recoveries are segregated into two categories—site specific and not site specific or unassigned.
 - b. Actual site specific recoveries were assigned 100% against the actual September 30, 2016 deferred costs for those sites. Actual site specific recoveries will be updated to more current amounts during the course of this proceeding.
 - c. The portion of unassigned recoveries to apply against all September 30, 2016 deferred costs was determined by taking the actual costs as of September 30, 2016 as a proportion of the estimated total cost of all existing remediation projects. The estimated total cost was determined as the midpoint between the high and low estimate of total future costs. Actual unassigned recoveries will be updated to more current amounts during the course of this proceeding.
- 3. Consistent with paragraph 6 (e) of the Environmental Order, a five-year amortization period is being requested for the net deferred costs.

The following table depicts the total costs and recoveries included for recovery in this filing:

1

Table 2. Environmental Deferred Costs and Recoveries

Description	Electric	Gas
Actual Costs through September 30, 2016	\$ 9,596,412	\$ 77,757,936
Less Site Specific Recoveries	-	(5,565,453)
Subtotal Net Deferred Costs	9,596,412	72,192,483
Total Unassigned Recoveries	(5,344,209)	(50,267,725)
Portion of Actual to Total Expected Costs	46%	58%
Unassigned Recoveries to Include	(2,483,527)	(29,385,479)
Total Net Deferral Requested	\$ 7,112,885	\$ 42,807,005
Amortization Over a Five Year Period	\$ 1,422,577	\$ 8,561,401

2

Based on the above, after taking income taxes into consideration, the adjustment

3

decreases net operating income for electric operations by \$924,675 and for natural

4

gas operation by \$5,564,911.

5

Adjustment Nos. 6.20 Payment Processing Costs

6

The adjustment incorporates the costs associated with the no-fee credit card

7

program approved in Order 01 in Dockets UE-160203 and UG-160204. Please

8

refer to the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit

9

No. ___(KJB-1T) for the detailed discussion on this adjustment.

10

The impact of this pro forma adjustment is to decrease net operating income for

11

natural gas by \$2,225,700.

1 **Adjustment Nos. 6.21E&G South King Service Center**

2 PSE purchased the South King Service Center, which it had previously been
3 leasing, and placed it into service on the purchase date of August 31, 2016. As a
4 service center, the facility provides services to both electric and gas customers.
5 This pro forma adjustment captures the addition of the net plant, land, and
6 associated depreciation as well as the retirement of the existing leasehold
7 improvements that were capitalized during the time the building was under lease.
8 Additionally, the adjustment removes the monthly lease payments from the test
9 year. PSE anticipates the operating expenses associated with the facility will not
10 change from the test year levels.

11 The total capital cost recorded for the South King Service center was
12 \$30,669,675, which is allocated between electric and gas based on the four-factor
13 allocator. The gross plant balance of the purchase was calculated on an AMA
14 basis for the rate year and, when compared to the test year AMA, results in an
15 increase to rate base of \$18,038,011 for electric and \$8,812,259 for natural gas.
16 These can be found on line 3 of each adjustment.

17 Line 14 of each adjustment represents the adjustment to bring depreciation
18 expense to an annual amount based on the proposed depreciation rates in the
19 depreciation study. The test year amounts shown on this line represent test year
20 depreciation based on the existing depreciation rate. Accordingly, in order to
21 prevent double counting of the portion of the depreciation study adjustment Nos.
22 6.06E&G that adjusts the test year depreciation expense for the South King

1 building, line 15 shows the amount included in the depreciation study adjustment
2 in order to recognize the test year depreciation expense has already been partially
3 adjusted. The total of lines 14 and 15 for these two adjustments is \$89,248 for
4 electric and \$43,601 for natural gas.

5 The accumulated depreciation on the building purchase was calculated on an
6 AMA basis for the rate year and is shown on line 5 of each adjustment, and the
7 corresponding adjustment to recognize the portion of the adjustment to
8 accumulated depreciation already recognized in the depreciation study
9 adjustments is included on line 6. The total of lines 5 and 6 for these two
10 adjustments are equal to (\$1,189,138) for electric and (\$580,939) for natural gas.

11 As the leasehold improvements previously capitalized on PSE's books were
12 purchased with the building, they were retired on the purchase date. Their AMA
13 balance in the test year is adjusted to zero on line 4 of each adjustment resulting in
14 an adjustment for electric of (\$2,296,591) and for natural gas of (\$1,121,972). The
15 AMA balance in the test year of their accumulated amortization is adjusted to
16 zero on line 7 of each adjustment resulting in an adjustment for electric of
17 \$1,087,774 and for natural gas of \$531,419. Because the leasehold improvements
18 were not fully amortized by the time they were retired, the negative reserve that
19 resulted from their retirement was transferred to the building capital asset. Finally,
20 their amortization expense from the test year is adjusted to zero on line 16
21 resulting in an adjustment for electric of (\$393,262) and for natural gas of
22 (\$192,123).

1 The deferred taxes associated with the tax depreciation of the South King Service
2 Center were calculated in the manner prescribed by the Internal Revenue Code
3 Regulations, Section 1.167(1)-1(h). For the service center the deferred tax
4 calculation is based on thirty-nine year tax depreciation which is not eligible for
5 bonus depreciation. The adjustment to the accumulated deferred tax liability
6 (“ADIT”) is shown on line 8 of each adjustment and the effect of the ADIT
7 already included in the depreciation study adjustments is shown on line 9. The
8 total effect of lines 8 and 9 for these two adjustments is \$275,003 for electric and
9 \$134,349 for natural gas.

10 Finally, the rent charged to O&M during the test year was eliminated in both
11 adjustments on line 13 and totals (\$363,750) for electric and (\$177,706) for
12 natural gas.

13 This adjustment increases rate base by \$15,915,060 and net operating income by
14 \$434,046 for electric operations and increases rate base by \$7,775,116 and net
15 operating income by \$212,048 for natural gas operations.

16 **Adjustment Nos. 6.22E&G Excise Tax and Filing Fee**

17 This restating adjustment adjusts the Washington State excise tax and WUTC
18 filing fee to the amount that should be recorded for these costs based on the level
19 of applicable revenue recorded in the test year. This adjustment increases net
20 operating income for electric operations by \$10,262 and for natural gas operations
21 by \$33,509.

1 **B. Exhibit No. ____ (SEF-7) Gas Only Adjustments**

2 **Q. Please explain Exhibit No. ____ (SEF-7).**

3 A. Exhibit No. ____ (SEF-7) presents the gas only adjustment in this case, which is
4 described in more detail below:

5 **Adjustment No. 7.01 Gas Cost Recovery Mechanism**

6 On December 31, 2012, the Washington Utilities and Transportation Commission
7 issued a policy statement in Docket UG-120715 for the accelerated replacement
8 of natural gas pipeline facilities with elevated risk. This policy statement requires
9 each gas company requesting a special pipe replacement cost recovery mechanism
10 (“Gas CRM”) to file with the Commission a pipe replacement program plan
11 (“PRPP”). In accordance with the policy statement, PSE developed and filed on
12 May 31, 2013, a PRPP under Docket PG-131839. The Two-Year Action Plan
13 filed with the PRPP listed the Aldyl “HD”, Wrapped Steel Mains, and Wrapped
14 Steel Services projects that were planned for completion in the 2013 Gas CRM
15 year, as well as the prioritization for projects in the Gas CRM years 2014 and
16 2015. On October 30, 2013 the Commission issued Order 1 approving PSE’s
17 PRPP, including the Two-Year Action Plan component.

18 Consistent with the approved Action Plan, in October 2014, PSE submitted to the
19 Commission its final 2014 Gas CRM program year filing for the time period of
20 November 2013 through October 2014, which was approved in Docket UG-
21 141212. The total amount of investment for that period (“the 2014 layer”) was
22 \$18,073,753. On June 1, 2015, PSE filed its second PRPP in Docket PG-160294,

1 which contained an updated Master Plan and Two-Year Plan covering 2015 –
2 2017. The second PRPP was approved on April 7, 2016. In October 2015, PSE
3 submitted its 2015 Gas CRM program year filing for the time period of November
4 2014 through October 2015, which was approved in Docket UG-151159. The
5 total amount of investment for that period (“the 2015 layer”) was \$42,608,867.
6 The most recent Gas CRM filing with the Commission was filed in Docket UG-
7 160791 for the 2016 program year. It was based on PSE’s Two-Year Plan from
8 Docket PG-160294, and the rate filing was approved on October 27, 2016 for
9 rates effective November 1, 2016. The total amount of investment (“the 2016
10 layer”) included in that filing was \$51,815,963, which represented actual
11 investment from November 2015 through September 2016, and a forecasted
12 amount for October 2016, which will be trued up in PSE’s next Gas CRM filing
13 on June 1, 2017, for rates effective November 1, 2017.

14 Paragraph 62 of the Commission policy statement says “the CRM would have an
15 effective life of four years with a general rate case filing required at the end of the
16 life to fold plant investment into base rates and adjust the CRM” (p. 16).

17 Additionally, paragraph 70 of the policy statement, says “after the Commission
18 has approved a CRM for a company, any general rate case filing must include all
19 plan investment in base rates and reset the tariff to exclude any CRM recovery.”

20 By the time rates are effective in this general rate case, there will be four years of
21 investment included in PSE’s Gas CRM program, and this is PSE’s first general
22 rate case after PSE began utilizing the gas cost recovery mechanism. Accordingly,
23 an adjustment is required to maintain conformity with the policy statement. The

1 policy statement is not prescriptive on how paragraphs 62 and 70 should be
2 implemented. PSE believes that the intent of paragraphs 62 and 70 of the policy
3 statement is to not end up with an impact on rates when transferring the recovery
4 of Gas CRM investment. However, in determining how to structure this
5 adjustment, it has become clear that transferring cost recovery of PSE's Gas CRM
6 investment from Schedule 149 to base rates poses some unique challenges. First,
7 Gas CRM investment is currently being recovered on an accelerated basis in
8 Schedule 149 on a modified end of period basis while the base rates revenue
9 requirement is based on historical rate base on an AMA basis. Additionally, at the
10 time rates are set in this proceeding, PSE will have very recently implemented its
11 fourth rate change under Schedule 149, which will be effective November 1,
12 2017. That rate change would theoretically include the 2014 through 2016 layers
13 that were discussed above plus the investment that occurred between November
14 2016 through September 2017 with one forecasted month for October 2017
15 ("2017 layer").

16 After carefully considering these challenges, PSE proposes the following
17 approach to transition the Gas CRM investment into base rates:

- 18 • In the next gas Schedule 149 CRM filing, PSE will include
19 recovery of the following:
 - 20 ▲ Two months of recovery covering the period November
21 through December 2017 for the 2014 through 2016 layers –
22 the 2016 layer will have had October 2016 trued up from
23 its current budgeted amount to actual. Therefore, there will
24 be no rate recovery for the 2014 through 2016 layers in
25 Schedule 149 for January 2018 forward as it will be
26 included in base rates from this proceeding. (See bullet 2).

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▲ Twelve months of recovery for the 2017 layer as would normally be included

- In the base rates revenue requirement in this proceeding, include an adjustment to pro form the rate base and depreciation expense for the 2014 through 2016 layers to the rate year (January through December 2018) and remove the associated Schedule 149 revenue for these layers. This will have the effect of establishing a deficiency associated with these layers that will be incorporated in the base-rates rate change in this proceeding.

PSE believes this treatment is consistent with the intent of the policy statement as it will effectuate the transfer of the rate recovery for the Gas CRM investment from Schedule 149 to base rates with minimal rate impact associated with the 2013 through 2016 layers of Gas CRM investment.

Line 2 of the adjustment removes \$6.3 million of Schedule 149 revenues that were recognized in the test period.

Line 5 of the adjustment brings depreciation expense to an annual amount based on the proposed depreciation rates in the depreciation study. The test year amounts shown on this line represent test year depreciation based on the existing depreciation rate. Accordingly, line 6 shows the amount of adjustment that has been included in the depreciation study adjustment² for gas mains and services in order to recognize that test year depreciation expense has already been partially adjusted.

Line 23 of the adjustment pro forms the test year AMA for Gas CRM investment to the rate year AMA balances. The accumulated depreciation was calculated on

² Page 6 of Exhibit No. ____ (SEF-6).

1 an AMA basis for the rate year utilizing the new depreciation rates effective
2 January 1, 2018 and is shown on line 24. Line 25 contains the corresponding
3 adjustment to recognize the partial adjustment to accumulated depreciation that
4 has already been performed in the depreciation study adjustment.³ Line 26 shows
5 the adjustment for the accumulated deferred federal income taxes (“ADIT”) at the
6 rate year level calculated in the manner prescribed by Internal Revenue Code
7 Regulations, Section 1.167(1)-1(h). Finally, the adjustment on line 27 shows the
8 corresponding adjustment to recognize the partial adjustment to ADIT that has
9 already been performed in the depreciation study adjustment.⁴

10 The overall impact of this adjustment shown on lines 20 and 29 is a decrease to
11 net operating income of \$4,003,724 and an increase to rate base of \$19,011,708

12 V. CONCLUSION

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

14 **A.** Yes, it does.

³ *Id.*

⁴ *Id.*