EXH. SEF-1Tr
DOCKETS UE-190529/UG-190530
2019 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-190529 Docket UG-190530

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

SUSAN E. FREE

ON BEHALF OF PUGET SOUND ENERGY

REVISED
AUGUST 22, 2019

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF SUSAN E. FREE

CONTENTS

I. INTRODUCTION 1

II. SUMMARY OF PROPOSED ELECTRIC AND NATURAL GAS REQUESTED REVENUE 2

III. REVENUE REQUIREMENTS 5

A. Exh. SEF-3 Net Revenue Change Requested 7

B. Exh. SEF-4 Electric and Natural Gas Summary 14

C. Exh. SEF-5 Electric and Natural Gas Test Year Data 16

IV. INDIVIDUAL ADJUSTMENTS 18

A. Exh. SEF-6 Common Adjustments 20

B. Exh. SEF-7 Electric Only Adjustments 60

C. Exh. SEF-8 Natural Gas Only Adjustments 70

V. ATTRITION BASE AMOUNTS 72

VI. POWER COST ADJUSTMENT MECHANISM 75

VII. CONCLUSION 76

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF SUSAN E. FREE

LIST OF EXHIBITS

Exh. SEF-2	Summary of Qualifications
Exh. SEF-3	Electric and Natural Gas Revenue Net Revenue Change Requested
Exh. SEF-4	Electric and Natural Gas Summary Pages, Detailed Summaries
Exh. SEF-5	Electric and Natural Gas Test Year Rate Base, Working Capital, Allocation Methods and Cost of Capital
Exh. SEF-6	Revenue Requirement Restating and Proforma Adjustments – Common to Electric and Natural Gas
Exh. SEF-7	Revenue Requirement Restating and Proforma Adjustments – Electric Only
Exh. SEF-8	Revenue Requirement Restating and Proforma Adjustments – Natural Gas Only
Exh. SEF-9	Determination of Attrition Basis Amounts for Electric and Natural Gas
Exh. SEF-10	Five Year Cost per Customer
Exh. SEF-11	Exhibit A-1 – Power Cost and Fixed Production Cost Baseline Rate

PUGET SOUND ENERGY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Susan E. Free. My business address is 355 110th Ave. NE, Bellevue, WA 98004. I am the Manager of Revenue Requirement for Puget Sound Energy ("PSE").

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

A. Yes. Please see the First Exhibit to the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-2, for an exhibit describing my education, relevant employment experience, and other professional qualifications.

Q. Please summarize the purpose of your testimony.

A. My testimony and exhibits in this proceeding will address the calculation of the revenue requirement and the associated requested revenue change after attrition for electric and natural gas operations. I also provide an updated baseline rate for use in PSE's Power Cost Adjustment ("PCA") mechanism.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the First Exhibit to the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-2, through the Tenth Exhibit to the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-11.

II. SUMMARY OF PROPOSED ELECTRIC AND NATURAL GAS REQUESTED REVENUE

Q. Please summarize PSE's requested net revenue change to electric and natural gas revenue.

A. PSE is requesting a net revenue change of $139.9 million for electric and $65.5 million for natural gas as reflected in Table 1 below.

Table 1. Net Revenue Change Requested (amounts in millions)

DESCRIPTION	ELECTRIC	GAS	COMBINED
1. Revenue Charge Before Attrition and Riders	$104.5	$86.1	$190.6
2. Changes to Other Price Schedules	$(3.1)	$(32.4)	$(35.5)
3. Net Revenue Change Before Attrition	$101.4	$53.7	$155.1
4. Attrition Adjustment	$44.5	$22.1	$66.6
5. Net Revenue Change After Attrition	$145.9	$75.8	$221.7
6. Reduction to Supported Amount	$(6.0)	$(10.4)	$(16.4)
7. Net Revenue Change Requested	$139.9	$65.5	$205.4

Q. How will PSE change its rates to achieve the requested net revenue change?

A. As discussed in the Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T, PSE's current rate structure is recovering its base revenue in multiple rate schedules. The following provides a summary:

- Base Rates – 2017 general rate case updated for tax reform (Dockets UE-180282 and UG-180283)
- Schedule 141 and 141X– expedited rate filing (Dockets UE-180899 and UG-180900)
- Schedule 149 – natural gas cost recovery mechanism (Docket UG-180514)
- Schedule 95 – electric only to reflect the loss of load and the resulting increase in unit costs associated with the Microsoft exit (Docket UE-190223)

Because PSE's base revenues are being recovered in multiple rate schedules, the requested net revenue change for electric and natural gas will be achieved by changing all of the base and adjusting rate schedules listed above. In its direct filing, PSE has not filed changes to the tariffs for all of the rate schedules listed below. Rather, as discussed by Mr. Piliaris, changes to certain of the schedules will be filed at the same time as the compliance filing in this case. The following is a summary of how PSE is proposing to change its base and adjusting rate schedules in this proceeding or at the time of compliance:

- Base rates will be increased to reflect the revenue requirement requested in this proceeding.
- Schedule 141 and 141X will be set to zero.
- The portion of Schedule 95 that is recovering the loss of load associated with the Microsoft exit will be set to zero.
- The portion of Schedule 149 that is recovering the investment approved in UG-180514 will be set to zero as these amounts are being transferred to base rates.

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

A. No. My testimony will focus only on determining PSE's revenue requirement. I will discuss the amount that base rates are deficient (equivalent to the revenue change before attrition and riders shown on line 1 in Table 1) based on this revenue requirement.

Q. Is PSE proposing an attrition adjustment in this case?

A. Yes. The Prefiled Direct Testimony of Mr. Ronald J. Amen, Exh. RJA-1T, provides the justification and support for a proposed attrition adjustment in this case. Mr. Amen provides the attrition deficiencies associated with PSE's delivery and fixed production revenues and costs, which I rely on to determine the total supported attrition deficiency in this filing. To Mr. Amen's electric attrition deficiency, I add the deficiency associated with power costs. The resulting amounts represent the Net Revenue Change After Attrition presented on line 5 of Table 1. These amounts represent the total revenue deficiency supported by PSE's filing.

As discussed in the Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T, PSE is not requesting the full attrition revenue deficiency in this proceeding but has set the level of its request to 6.9 percent on electric and 7.9 percent for natural gas, shown as the Net Revenue Change Requested on line 7 in Table 1, which would be expected to occur at the compliance filing based on the net revenue change requested in this proceeding.

III. REVENUE REQUIREMENTS

Q. Please explain how this filing was prepared.

A. Per WAC 480-07-510 PSE must provide a detailed portrayal of the restating and pro forma adjustments in its testimony and exhibits. In order to discuss the restating adjustments independent of the pro forma adjustments, PSE has set up each of its adjustments to show the restating adjustments separately from the pro forma adjustments, as the restating adjustments are the basis upon which pro forma adjustments must be calculated per WAC 480-07-510. Additionally, PSE used the following steps to determine the revenue requirement for this proceeding:

1. **Test Year Results of Operation** – PSE started with the test year results of operations for the twelve months ended December 31, 2018, as presented in Exh. SJK-3 to the Prefiled Direct Testimony of Mr. Stephen J. King. The test year rate base is included in Exh. SEF-5. Following the treatment in its most recent general rate case, PSE's rate base was developed using the historical average of the monthly average ("AMA") of the balances for the 13 months ended December 31, 2018. As is discussed later in my testimony, through a restating adjustment, the average net plant in service balances were adjusted to the end of period ("EOP") balances as of December 31, 2018.

2. **Restating Adjustments** – PSE prepared restating adjustments to adjust the test year operating results to reflect the results on a basis the

Commission accepts for determining rates. The restating adjustments are necessary to annualize ongoing costs and revenues that PSE began to incur and realize part way through the test year and to adjust the balances to normalized levels consistent with historical ratemaking practices.

3. **Pro forma Adjustments** – The sum of values resulting from Steps 1 and 2 reflect the restated results of operations upon which pro forma adjustments must be based. Among its pro forma adjustments, PSE has included adjustments to reflect capital projects that will be in service during the rate year. The case includes five pro forma capital additions that are projected to be placed in service before June 30, 2019. The pro forma capital additions are discussed in further detail in the prefiled direct testimonies of Ms. Margaret F. Hopkins, Mr. Joshua J. Jacobs, and Ms. Catherine A. Koch. Additionally, pro forma adjustments to amortize previously deferred costs have been included for consideration and approval by the Commission. The main pro forma deferral adjustments consist of amortization of deferred costs for (i) new qualifying storms, (ii) Advanced Metering Infrastructure ("AMI")[1], and (iii) Get To Zero[2] ("GTZ") projects.

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[1] The deferral of which was approved in Dockets UE-180899 and UG-180900.

[2] As requested for deferral in Dockets UE-190274 and UG-190275.

A. Exh. SEF-3 Net Revenue Change Requested

Q. Would you please explain Exhs. SEF-3E and SEF-3G?

A. Exh. SEF-3E presents the calculation of the electric revenue change before attrition and riders and the net revenue change requested based on the restated and pro forma results, a limited attrition adjustment and changes to other price schedules. It also presents the pro forma cost of capital and the electric conversion factor. Further, it provides the determination of the overall attrition revenue deficiency based on the amounts supported by Mr. Amen and the deficiency associated with power costs.

Exh. SEF-3G presents the calculation of the natural gas base revenue change before attrition and riders and the net revenue change requested based on the restated and pro forma results, a limited attrition adjustment and changes to other price schedules. It also presents the pro forma cost of capital, and the natural gas conversion factor.

The following are descriptions of the individual pages in Exh. SEF-3E and Exh. SEF-3G.

Electric Net Revenue Change Requested

The electric net revenue change requested is shown on page one of Exh. SEF-3E. The schedule shows the test period pro forma and restated rate base, line 1, requested rate of return, line 2, operating income requirement, line 4 and the revenue change before attrition and riders, line 10.

Based on $5.4 billion invested in rate base, a 7.62 percent rate of return and $335.1 million of pro forma base rates operating income, PSE requires a revenue change before attrition and riders for electric base rates of $104.5 million. After the expected reduction to other price schedules, supported by Mr. Piliaris, of $3.1 million on line 15, the net revenue change before attrition is presented on line 17. The attrition adjustment on line 19 is determined as the difference between the net revenue change before and after attrition (line 21 minus line 17). The net revenue change after attrition is determined on pages 4 through 6 of the exhibit and represents the electric attrition deficiency for delivery and fixed production as supported by Mr. Amen plus the deficiency associated with power costs. PSE's net revenue change requested for electric shown on line 25 is $139.9 million.

Natural Gas Net Revenue Change Requested

The gas net revenue change requested is shown on page one of Exh. SEF-3G. This page shows the test period pro forma and restated rate base, line 1, requested rate of return, line 2, operating income requirement, line 4, pro forma operating income, line 6, and the revenue change before attrition and riders, line 10.

Based on $2.1 billion invested in rate base, a 7.62 percent rate of return and $96.0 million of pro forma base rates operating income, PSE requires a net revenue change for natural gas revenues of $86.1 million. After the expected reduction to other price schedules supported by Mr. Piliaris of $32.4 million on line 15 and the limited attrition adjustment supported by Mr. Pilaris and Mr. Amen on lines 19 and 23 of $11.8 million, PSE's net revenue change requested for natural gas shown on line 25 is $65.5 million.

<u>Causes of the Net Revenue Change Before Attrition</u>

As was discussed above, the revenue change before attrition is $101.4 million for electric and $53.7 million for natural gas. Please see the Prefiled Direct Testimony of Mr. Daniel A. Doyle for discussion of why PSE has not achieved its authorized rate of return and what actions the company has taken to improve its earnings prior to filing a request for increased rates. As discussed by multiple witnesses in this filing, the need for the revenue change primarily results from increased investment in safety, reliability and technology infrastructure. Table 2 below provides an overview of the drivers of the net revenue change before attrition requested in this proceeding:

Table 2. Causes for Net Revenue Change Before Attrition (in millions)

Net Revenue Change Before Attrition	Electric	Natural Gas	Combined
Change in Rate Base	$19.7	$26.4	$46.1
Depreciation and Amortization	71.3	45.7	117.0
Deferral Amortizations	10.3	6.6	16.9
Storm Amortization	7.9	0.0	7.9
Revenue and Billing Determinants	(3.5)	(21.8)	(25.3)
Other	(4.3)	(3.2)	(7.5)
Net Revenue Change	$101.4	$53.7	$155.1

Cost of Capital for Electric and Natural Gas

Page two of both Exh. SEF-3E and Exh. SEF-3G reflects the proposed capital structure for PSE 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 Matthew D. MacArthur, Exh. MDM-1T. The requested rate of return is 7.62 percent and 7.02 percent net of tax. Please see the Prefiled Direct Testimony of Matthew D. McArthur, Exh. MDM-1T, for support for the requested capital structure and components of the cost of debt. Please also see the Prefiled Direct Testimony of Dr. Roger A. Morin, Exh. RAM-1T, for support for the requested return on equity of 9.80 percent.

Electric and Natural Gas Conversion Factors

Page three of both Exh. SEF-3E and Exh. SEF-3G provides, respectively, the electric and natural gas conversion factors that are used to adjust the electric and natural gas net operating income deficiency for revenue sensitive items and federal income tax to determine the total electric and natural gas requested net revenue change. The revenue sensitive items are the Washington State utility tax, Washington Utilities and Transportation Commission ("WUTC" or "Commission") annual filing fee, and bad debts. These conversion factors are 0.751381 for electric operations and 0.754097 for natural gas operations.

Q. Did PSE employ a materiality threshold for its proposed restating and pro forma adjustments?

A. Yes. PSE relied on the definition provided in the testimony of Ms. Melissa C. Cheesman on behalf of Commission Staff in PSE's 2017 general rate case, Dockets UE-170033 and UG-170034 when developing its restating and pro forma adjustments. In that proceeding, Commission Staff considered a material effect to be one that impacts the rate of return by one basis point. The materiality threshold relevant to this proceeding based on this definition is shown below in Table 3. For electric, the net operating income threshold is $500,000 and the rate base threshold is $9.5 million. For natural gas, the net operating income threshold is $200,000 and the rate base threshold is $3.7 million.

Table 3. Materiality Thresholds

DESCRIPTION	PER SEF-3E PAGE 1	ROR 1 BASIS POINT LOWER	ELECTRIC MATERIALITY THRESHOLD	PER SEF-3G PAGE 1	ROR 1 BASIS POINT LOWER	NATURAL GAS MATERIALITY THRESHOLD
1. RATE BASE	$5,428,588,081	$5,428,588,081		$2,112,672,666	$2,112,672,666	
2. RATE OF RETURN	7.62%	7.61%		7.62%	7.61%	
3. OPERATING INCOME REQUIREMENT	$413,658,412	$413,115,553		$160,985,657	$160,774,390	
4. PRO FORMA OPERATING INCOME	$335,137,120	$335,137,120		$96,036,531	$96,036,531	
5. NET OPERATING INCOME THRESHOLD	$78,521,292	$77,978,433	542,859	$64,949,126	$64,737,859	$211,267
6. CONVERSION FACTOR	0.751381	0.751381	0.751381	0.754097	$0.754097	0.754097
7. IMPACT ON NET REVENUE CHANGE TO BASE RATES	$104,502,632	$103,780,150	722,481	$86,128,345	$85,848,185	280,159
8. DIVIDE BY RATE OF RETURN FOR RATE BASE THRESHOLD			7.62%			7.62%
9. RATE BASE THRESHOLD ROUNDED			$9,500,000			$3,700,000

PSE utilized this definition and resulting materiality amounts to determine whether there were any standard general rate case adjustments that may be suitable to be discontinued as their results are consistently below the materiality threshold. PSE identified two standard adjustments that are consistently below the thresholds, and PSE requests Commission authorization to discontinue these adjustments in future rate cases. PSE has prepared these restating adjustments as usual and then presented an offsetting pro forma adjustment to remove the restating adjustment. The two adjustments are:

Director's and Officer's Insurance:

This restating only adjustment annualizes insurance proceeds and adjusts the percentage of total premiums charged above the line to align with test year allocation factors. Because PSE periodically adjusts the allocations used to record the insurance expense on the books, there has been little true-up needed to the amounts recognized in any given test year. In the last five Commission Basis Reports, this adjustment has varied between $2,900 and $11,400 for electric and $2,100 and $8,200 for natural gas.

Excise Tax and Filing Fee:

This restating only adjustment restates the level of expense and fees to match test year revenues. Because amounts recorded in the test year are matched to the test year revenue, these adjustments are typically immaterial. In the last five Commission Basis Reports, this adjustment has varied between $-42,000 and $72,000 for electric and $-7,300 and $70,000 for natural gas.

Q. Are there other adjustments in this filing that fall below the calculated materiality threshold but for which you are not asking to discontinue performing in future cases?

A. Yes. Other adjustments do fall below the materiality threshold but have the potential to be material in the future. PSE is not requesting to discontinue performing those adjustments in future cases and has included them in this case. An example is the incentive adjustment, which is below the materiality threshold in this case but has the potential to be material in future cases, depending on whether the four-year average varies greatly from the accrued incentive expense in a given test year. It can also be an immaterial adjustment if the test year accrued incentive expense approximates the four-year historical average. Accordingly, it is better to perform these adjustments in every case in order to ensure they are included when material. Likewise, PSE did include some pro forma adjustments to rate base, such as the HR Tops adjustment, that in total were slightly below the calculated thresholds. In other words, PSE did not utilize the thresholds as a bright line and chose to make adjustments that were close to the thresholds for short-lived assets that warranted inclusion as a pro forma adjustment.

B. Exh. SEF-4 Electric and Natural Gas Summary

Q. Would you please explain both Exh. SEF-4E and Exh. SEF-4G?

A. Exhs. SEF-4E and SEF-4G present an overview of the income statement and rate base starting with the unadjusted test year through the adjusted results of operations.

The first page of Exhs. SEF-4E and SEF-4G presents the impact of each of the respective electric and natural gas restating and pro forma adjustments being made to the December 31, 2018 operating income statement and rate base.

- Column a presents the unadjusted operating income statement and the AMA rate base for PSE as of December 31, 2018 (the test year) and is labeled actual results of operations. As stated above, the income statement amounts are supported by Mr. King.
- Column b presents the total restating adjustments.
- Column c is the sum of columns a and b (actual results of operations plus restating adjustments) and this total is referred to as the restated results of operations.
- Column d presents the total pro forma adjustments.
- Column e is the sum of columns c and d (restated results of operations plus pro forma adjustments) and is referred to as the adjusted results of operations. It is used to calculate the revenue change before attrition and riders.
- Column f presents the revenue change before attrition and riders.
- Column g presents the impact on the operating income and rate base. It is calculated by adding the amount in column f to the adjusted results of operations and shows that the net operating income divided by the adjusted rate base results in the requested rate of return.

Pages two through seven of Exh. SEF-4E and pages two through five of Exh. SEF-4G present a detailed summary schedule for all of the respective electric or natural gas restating and pro forma adjustments that support the summary on page one of Exh. SEF-4E for electric and Exh. SEF-4G for natural gas.

- The first column of numbers on page two of both Exh. SEF-4E and Exh. SEF-4G is the unadjusted net operating income for the year ended December 31, 2018 and the unadjusted rate base for the same period.
- Each column to the right of the first column represents a restating adjustment to net operating income or rate base and has a supporting schedule, which is referenced by the adjustment number shown in each column title.
- These columns are then subtotaled in column ab on page four of Exh. SEF-4E for electric and in column v on page three of Exh. SEF-4G for natural gas.
- The restated results of operations are immediately to the right in column ac for electric and column w for natural gas. The rate of return shown in these columns—6.75 percent on line 38 for electric and 5.02 percent on line 36 for natural gas— are well below (i) PSE's authorized rate of return of 7.60 percent from PSE's general rate case in Dockets UE-170033 and UG-170034, and (ii) the rate of return of 7.49 percent agreed to for earnings sharing purposes in PSE's 2018 expedited rate filing ("ERF") in Dockets UE-180899 and UG-180900.
- The remaining adjustments shown represent the pro forma adjustments to net operating income or rate base.
- These columns are also subtotaled on page seven for electric and page five for natural gas.
    - For electric, column be presents the total pro forma adjustments and bf presents the pro forma results of operations. These are used to calculate the revenue change before attrition and riders in Exh. SEF-3E.

- For natural gas, column as presents the total pro forma adjustments and column at presents the pro forma results of operations. These are used to calculate the revenue change before attrition and riders in Exh. SEF-3G.

C. Exh. SEF-5 Electric and Natural Gas Test Year Data

Q. Would you please explain both Exh. SEF-5E and Exh. SEF-5G?

A. Exhs. SEF-5E and SEF-5G present the respective electric and natural gas test year rate base, working capital, allocation methods and cost of capital.

Rate Base

Pages one and two of Exh. SEF-5E and page one of Exh. SEF-5G present the test year AMA and EOP rate base calculation for electric and natural gas, respectively. Because the Commission approved rate base and working capital on an AMA basis in PSE's last general rate case, the rate base and working capital presented for the test year in this proceeding are also reported on an AMA basis. I discuss in more detail later in my testimony the adjustment that is made to reflect PSE's rate base and working capital on an end of period basis.

Investor Supplied Working Capital

Page three of Exh. SEF-5E and page two of Exh. SEF-5G present the test year working capital calculation for electric and natural gas, respectively, that is included as part of the respective rate base calculations. In PSE's 2017 general rate case, Dockets UE-170033 and UG-170034, the settling parties agreed to a new presentation of investor supplied working capital and also agreed to revised treatment for certain accounts including the inclusion of construction work in progress in the determination of the working capital ratio in the final investor supplied working capital calculation. PSE has used this revised presentation and account treatment in the calculation of test year investor supplied working capital included in this filing.

<u>Allocation Factors</u>

Page four of Exh. SEF-5E and page three of Exh. SEF-5G present the allocation methods and factors used in allocating common expenditures between electric and natural gas operations. Common utility plant is that portion of utility operating plant that is used for providing more than one commodity to customers, i.e., both electricity and natural gas service. Common plant includes costs associated with land, structures, and equipment, which are not charged specifically to electric or natural gas operations. PSE allocates its common utility plant for electric and natural gas by using the four-factor allocation method.

Common operating costs are those costs that are incurred on behalf of both electric and natural gas customers. PSE incurs common costs related to customer accounts expenses, customer service expenses, administrative and general expense, depreciation/amortization, other operating expenses, 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, (2) joint meter reading customers, (3) non-production plant, (4) four-factor allocator, and (5) direct labor allocator. An allocation factor that can be used in assigning total costs between operating costs, capital and non-utility when warranted is also presented on this exhibit.

<u>Cost of Capital</u>

Page five of Exh. SEF-5E and page four of Exh. SEF-5G present the cost of capital for the test year. This exhibit is presented to support the weighted average cost of debt that occurred during the test year, which is used to calculate the tax benefit of interest for restating purposes. PSE is proposing a different weighted average cost of capital for approval in this proceeding, which is supported in the Prefiled Direct Testimony of Dr. Roger A. Morin, Exh. RAM-1T and the Prefiled Direct Testimony of Matthew A. McArthur, Exh. MDM-1T. PSE's proposed weighted average cost of capital in this case is presented on page 2 of both Exh. SEF-3E and Exh. SEF-3G.

IV. INDIVIDUAL ADJUSTMENTS

Q. Please explain the organization of the individual adjustments.

A. Each of the individual adjustments can be common to both electric and natural gas operations or can be related to electric only or natural gas only. Additionally, each of these adjustments can be restating, pro forma or both restating and pro forma. And, even then, an adjustment can be comprised of multiple restating adjustments to the same cost category. In order to identify and summarize adjustments by business or type (electric and natural gas, restating and pro forma), PSE has used a numbering system that helps to identify which of these characteristics exist in each of the adjustments. Exhs. SEF-6E and SEF-6G contain adjustments that are common to both electric and natural gas. Exh. SEF-7 contains adjustments that only pertain to electric service, and Exh. SEF-8 contains adjustments that only pertain to natural gas operations. The letters “E” and “G” designate whether the adjustment relates to electric or natural gas. The letters “R” and “P” specify whether an adjustment is restating or pro forma. Table 4 below provides an overview of all the revenue requirement adjustments being made and identifies whether the adjustment is common, electric or natural gas only, and if it has a restating or pro forma component or both.

Table 4. Summary of Revenue Requirement Adjustments

		ELECTRIC		GAS	
Adj #	ADJUSTMENT	RESTATIN	PROFORMIN	RESTATIN	PROFORMIN
6.01	REVENUES & EXPENSES	6.01 ER	6.01 EP	6.01 GR	6.01 GP
6.02	TEMPERATURE NORMALIZATION	6.02 ER	6.02 EP	6.02 GR	6.02 GP
6.03	FEDERAL INCOME TAX	6.03 ER	N/A	6.03 GR	N/A
6.04	TAX BENEFIT OF INTEREST	6.04 ER	6.04 EP	6.04 GR	6.04 GP
6.05	PASS-THROUGH REV & EXP	6.05 ER	N/A	6.05 GR	N/A
6.06	NORMALIZE INJURIES & DAMAGES	6.06 ER	N/A	6.06 GR	N/A
6.07	BAD DEBTS	6.07 ER	N/A	6.07 GR	N/A
6.08	INCENTIVE PAY	6.08 ER	N/A	6.08 GR	N/A
6.09	EXCISE TAX & FILING FEE	6.09 ER	6.09 EP	6.09 GR	6.09 GP
6.10	D&O INSURANCE	6.10 ER	6.10 EP	6.10 GR	6.10 GP
6.11	INTEREST ON CUSTOMER DEPOSITS	6.11 ER	N/A	6.11 GR	N/A
6.12	RATE CASE EXPENSEs	6.12 ER	N/A	6.12 GR	N/A
6.13	PENSION PLAN	6.13 ER	N/A	6.13 GR	N/A
6.14	PROPERTY AND LIABILITY INSURANCE	6.14 ER	6.14 EP	6.14 GR	6.14 GP
6.15	WAGE INCREASE	6.15 ER	6.15 EP	6.15 GR	6.15 GP
6.16	INVESTMENT PLAN	6.16 ER	6.16 EP	6.16 GR	6.16 GP
6.17	EMPLOYEE INSURANCE	6.17 ER	6.17 EP	6.17 GR	6.17 GP
6.18	AMA TO EOP RATE BASE	6.18 ER	N/A	6.18 GR	N/A
6.19	AMA TO EOP DEPRECIATION	6.19 ER	N/A	6.19 GR	N/A
6.20	DEFERRED G/L ON PROPERTY SALES	N/A	6.20 EP	N/A	6.20 GP
6.21	ENVIRONMENTAL REMEDIATION	N/A	6.21EP	N/A	6.21GP
6.22	AMI	N/A	6.22 EP	N/A	6.22 GP
6.23	RENT EXPENSE	6.23 ER	6.23 EP	6.23 GR	6.23 GP
6.24	GET TO ZERO	N/A	6.24 EP	N/A	6.24 GP
6.25	CREDIT CARD PAYMENT PROCESSING FEES	N/A	6.25 EP	N/A	6.25 GP
6.26	UNPROTECTED EXCESS DEFERRED INCOME TAXES	N/A	6.26 EP	N/A	6.26 GP
6.27	PUBLIC IMPROVEMENT	N/A	6.27 EP	N/A	6.27 GP
6.28	CONTRACT ESCALATIONS	N/A	6.28 EP	N/A	6.28 GP
6.29	HR TOPS	N/A	6.29 EP	N/A	6.29 GP
7.01	POWER COSTS	7.01 ER	7.01 EP	N/A	N/A
7.02	MONTANA ELECTRIC ENERGY TAX	7.02 ER	7.02 EP	N/A	N/A
7.03	WILD HORSE SOLAR	7.03 ER	N/A	N/A	N/A
7.04	ASC 815	7.04 ER	N/A	N/A	N/A
7.05	STORM DAMAGE	7.05 ER	7.05 EP	N/A	N/A
7.06	REGULATORY ASSETS & LIAB	N/A	7.06 EP	N/A	N/A
7.07	COLSTRIP DEPRECIATION	7.07 ER	N/A	N/A	N/A
7.08	ENERGY IMBALANCE MARKET (EIM)	N/A	7.08 EP	N/A	N/A
7.09	HIGH MOLECULAR WEIGHT CABLE	N/A	7.09 EP	N/A	N/A
7.10	ENERGY MANAGEMENT SYSTEM (EMS)	N/A	7.10 EP	N/A	N/A
8.01	REMOVE 2018 CRM	N/A	N/A	N/A	8.01 GP
8.02	PROFORM EXISTING CRM	N/A	N/A	N/A	8.02 GP

A. Exh. SEF-6 Common Adjustments

Q. Please provide an explanation of Exhs. SEF-6E and SEF-6G.

A. Exh. SEF-6 presents the common adjustments that apply to both electric and natural gas operations. An explanation of each of the proposed common adjustments is presented below:

Adjustment Nos. 6.01ER, 6.01EP, 6.01GR and 6.01GP Revenues and Expenses

<u>Electric and Natural Gas Restating – Adjustments 6.01ER and 6.01GR:</u>

The restating adjustments included in this adjustment for electric and natural gas are those that are typically made in a Commission Basis Report ("CBR") that is filed annually under WAC 480-100-257 or WAC 480-90-257. Additional restating adjustments are included for required annualizing adjustments which are not allowed in a CBR. The electric and natural gas restating amounts in Adjustments <u>6.01ER and 6.01GR</u> are summarized as follows:

- For both electric and natural gas, this adjustment removes the credits passed back to customers associated with Schedule 132 Merger Rate Credit (line 2 for electric and lines 4 and 10 for natural gas).

- For electric only, this adjustment removes the credits passed back to customers and the related amortization associated with Schedule 95A Federal Incentive Tracker (lines 3 and 25 for electric only). The tax impacts associated with the Schedule 95A revenue and amortization are removed in the federal income tax adjustment, which is Adjustment 6.03ER.

- For electric only, this adjustment removes the expense associated with creating the regulatory liability associated with production tax credits ("PTCs") that was recorded during the test year (line 26 for electric only). The income tax credit associated with these PTCs is removed in the federal income tax adjustment, which is Adjustment 6.03ER.

- For electric and natural gas, this adjustment removes the accruals and true-ups recognized in the test year for the 2017 and 2018 earnings sharing (line 13 for electric and line 11 for natural gas).

- For electric only, this adjustment reclassifies electric transportation revenues in Other Operating Revenues (line 16) to Sales to Customers (line 7) to support the electric cost of service process.

- Beginning January 1, 2018, PSE began deferring revenue under Dockets UE-171225 and UG-171226 related to the federal tax rate change from 35 percent to 21 percent that became effective with the Tax Cuts and Jobs Act ("TCJA"). PSE continued the deferrals until April 2018 as PSE changed its base rates effective May 1, 2018 under Dockets UE-180282 and UG-180283 to incorporate the impacts to its current rates for the TCJA. Additionally, effective May 1, 2019, the over-collection for the time period January 1, 2018 through April 30, 2018 is being passed back to customers in Schedule 141-Y pursuant to Dockets UE-180899 and UG-180900. Accordingly, PSE's test year revenues need to be annualized for the impacts of the May 1, 2018 rate change, and the deferrals recorded in the period need to be removed from the test year. These annualizing adjustments are found on lines 6, 9 and 15 for electric and lines 5 and 13 for natural gas.

- For gas only, this adjustment includes the annualization of PSE's Schedule 101 revenues for the rate changes associated with its Purchased Gas Adjustment mechanism under Docket UG-180794 (lines 3, 15, and 22).

- Finally, certain other adjustments that are not specifically identified result from the process conducted by cost of service of reconciling the test year and pro forma results that are determined based on applying the most current base rates to the normalized pro forma billing determinants. These amounts are reflected on lines 10 for electric and lines 6 and 21 for natural gas.

Overall, adjustment 6.01ER increases net operating income for electric operations by $8.3 million and adjustment 6.01GR increases net operating income for natural gas operations by $1.0 million.

<u>Electric and Natural Gas Pro Forma Adjustments 6.01EP and 6.01GP:</u>

The pro forma amounts in this adjustment have been determined using the following approach:

- For electric and natural gas, modifies the test year revenues to the revenues that would have been collected during the test year if only the base rates from the 2017 general rate case as modified for tax reform in Dockets UE-180822 and UG-180283 had been in effect for the entire test year. The annualization of base rates revenue was discussed in the restating section. Also, as discussed in section II, my testimony focuses on determining and describing only the change in the revenue requirement related to base rates. Mr. Piliaris covers the change to the other rate schedules, which include Schedule 95 Power Cost Adjustment Clause, Schedule 149 Cost Recovery Mechanism for Pipeline Replacement, Schedule 141 Expedited Rate Filing Rate Adjustment, and Schedule 141X Protected-Plus Excess Deferred Income Tax (EDIT) Reversals Rate Adjustment. For purposes of determining the revenue requirement, the following steps were taken to reflect the revenue in the test year at 2017 general rate case tax reform levels:

- This adjustment removes the decoupling deferrals and amortization, including the associated twenty four month GAAP reserve, to reflect the test year revenue on a volumetric basis (lines 14 and 17 for electric and line 12 for natural gas).
- This adjustment removes the non-tracker/rider non-base rates revenue from the test year (lines 4 and 5 for electric and lines 2 and 10 for natural gas).
- The above two steps result in the test year revenue being reflected on a volumetric basis priced at 2017 general rate case tax reform base rates. Therefore, the final step is to weather normalize these revenues, which is performed in adjustments 6.02EP and 6.02GP and discussed further below in my testimony.

- PSE recognized natural gas revenues associated with curtailment and entitlement constraint periods that occurred during the test year. PSE declared these constraint periods in response to the conditions imposed by PSE’s upstream pipeline service provider, Northwest Pipeline Corp in response to the Enbridge pipeline outage. For the constraint period, if interruptible customers do not reduce or cease consumption and consume unauthorized volumes of natural gas, or if customers do not consume the amount of gas within the entitlement tolerance percentage, then they are required to pay specified amounts for that unauthorized consumption. The events which occurred during 2018 that resulted in the constraint periods were associated with the Enbridge pipeline outage. Therefore, PSE is assuming there will be no such curtailment events in the rate year and so is pro forming these amounts to zero as shown on line 14 of the natural gas pro forma adjustment.

- Line 8 (electric only) represents the migration of Schedule 40 customers, primarily Microsoft, which as of April 1, 2019 began taking service under a special contract. As part of the settlement approved by the Commission in PSE's 2017 GRC, parties agreed that PSE would terminate Schedule 40 in PSE's next general rate case. The remaining customers in Schedule 40 will be migrated to other schedules, with most locations taking service under Schedule 26.

- Finally, line 18 (electric only) represents the estimate of revenues to be received in the rate year from Powerex for the transmission of electricity for Microsoft on PSE facilities. This adjustment is appropriate now that Microsoft is under a special contract.

Overall, adjustment 6.01EP decreases net operating income for electric operations by $25.7 million and adjustment 6.01GP decreases net operating income for natural gas operations by $7.4 million.

Adjustment No. 6.02ER, 6.02GR, 6.02EP and 6.02GP Temperature Normalization

PSE's temperature normalization adjustment to load is supported in the Prefiled Direct Testimony of Lorin I. Molander, Exh. LIM-1T. The pricing of the adjustment to load is supported by Mr. Piliaris. As I discussed above, due to adjustments 6.01E and 6.01G, revenues have been reflected on a volumetric basis at 2017 general rate case base rates levels; therefore, the temperature normalization adjustment is necessary to restate and pro form test year delivered load and revenue to a level which would have been expected to occur had the temperatures during the test year been "normal". For electric operations, this adjustment is based on the difference between the actual test year Generated, Purchased and Interchange ("GPI") load for electric and the temperature normalized GPI megawatt hours ("MWh") adjusted for system losses. For natural gas operations, this adjustment is based on the difference between the actual test year therms and the temperature normalized therms. Because PSE is required to make restating adjustments prior to pro forma adjustments, for development of the revenue requirement, the total adjustment determined by Mr. Piliaris has been segregated between restating and pro forma. The restating adjustment normalizes all non-decoupled revenues in the test year and is equal to the adjustments made in PSE's CBR. The pro forma adjustment normalizes the remaining revenues that were reflected on a volumetric basis as a result of the adjustment to remove the current decoupling deferrals that was discussed above in adjustments 6.01E (line 14) and 6.01G (line 12).

The test year was warmer than normal requiring an adjustment to net operating income to bring revenues up to what would have occurred under normal conditions. The electric temperature load adjustments increase actual GPI by 145,584 MWh, or 135,248 MWh when adjusted for line losses. The natural gas load adjustments increase actual therms by 56.7 million therms. Ms. Molander discusses PSE's weather normalization methodology, and Mr. Piliaris supports the pricing of the load adjustments and their allocation to the rate classes based on the proposed rate class level weather normalization methodology.

The electric restating and pro forma adjustments increase net operating income for electric operations by $4.0 million and $6.8 million, respectively. The natural gas restating and pro forma adjustments increase net operating income for natural gas operations by $31,955 and $13.4 million, respectively.

Adjustment No. 6.03ER and 6.03GR Federal Income Tax

This adjustment restates the test year for the appropriate level of federal income tax ("FIT") expense for this case before the deduction for interest. On December 22, 2017, the President signed the TCJA into law. The TCJA resulted in excess deferred income tax assets and liabilities (including both "protected" and "unprotected"). The turn-around of the protected excess deferred taxes on the Average Rate Assumption Method ("ARAM") that occurred during the test year have not been adjusted pursuant to the Internal Revenue Service ("IRS") normalization requirements. This is discussed in more detail in the Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T. This adjustment includes the removal of the income tax credit associated with the PTC liability and the tax impacts associated with Schedule 95A that were removed in Adjustment 6.01ER discussed earlier. There is no comprehensive pro forma adjustment required for federal income taxes other than the federal tax impacts taken in all individual pro forma adjustments. The impact of this restating adjustment decreases net operating income for electric by $14.9 million and increases net operating income for natural gas by $1.2 million.

Adjustment No. 6.04ER, 6.04EP, 6.04GR, 6.04GP Tax Benefit of Interest

As in prior general rate cases, PSE has included an adjustment to capture the tax benefit of interest for electric and natural gas operations, which in the test year is all recognized below the line. This adjustment recognizes the tax deduction related to the level of interest associated with the restated and pro forma rate base.

The restating adjustment is calculated using the restated rate base and the weighted average cost of debt of 2.94 percent that was realized during the test year and that is shown on page five of Exh. SEF-5E and page four of Exh. SEF-5G. The pro forma adjustment is calculated using the pro forma rate base and the requested weighted average cost of debt of 2.87 percent that is shown on page two of both Exh. SEF-3E and Exh. SEF-3G. The restating adjustments increase net operating income by $33.1 million for electric and by $12.9 million for natural gas operations. The pro forma adjustments decrease net operating income by $0.4 million for electric and by $0.2 million for natural gas operations.

Adjustment No. 6.05ER, 6.05GR - Pass-through Revenue and Expense

This restating adjustment 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 rider, municipal and property taxes, the low-income rider and the decoupling adjustment mechanism. The associated expense that is recorded in the test year for these direct pass through tariffs are also removed in this adjustment.

The revenues and expenses associated with the electric residential exchange benefits provided by the Bonneville Power Administration, the electric green power program and the gas carbon offset program have also been removed along with the associated amortization. The green tags purchased as part of the green power program are recorded in Account 557 power costs and these amounts are removed in Adjustment 7.01ER Other Power Cost Expenses. Finally, renewable energy credit revenues passed back to customers and the associated amortization have been removed as well.

The net impact of these restating adjustments is to decrease net operating income for electric by $2.0 million and for natural gas by $1.4 million.

Adjustment No. 6.06ER, 6.06GR - Injuries and Damages

This restating adjustment restates injuries and damages to the three-year average of accruals and payments. When necessary, amounts are allocated to operations and maintenance ("O&M") based on the distribution of wages and then allocated between electric and natural gas based on the average number of customer's allocator. This adjustment increases net operating income for electric operations by $0.07 million and decreases natural gas operations by $1.3 million.

Adjustment Nos. 6.07ER, 6.07GR - Bad Debt

Consistent with prior cases, 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. This adjustment is calculated for electric and natural gas operations. Since it takes four months to write-off a bill, the ratio of the write-off versus revenue is offset four months. For example, a write-off booked in December is actually related to revenue that was recognized during the previous August. Using this relationship between August revenues and December write-offs results in the calculation of an appropriate percentage of write-offs associated with revenues in the test year. The bad debt percentage for a given year is calculated by taking the actual write-offs for the test year and dividing them by the net revenues for twelve months ending in August for each of the years. The net test year revenues as adjusted are multiplied by the calculated average bad debt percentage to determine the amount of restated bad debt expense. This normalized amount is compared to the actual test year level of bad debt expense to determine the effect on income. This bad debt percentage is also used in the conversion factor when determining the final revenue requirement.

The impact of this adjustment on net operating income is an increase of $0.3 million for electric and a decrease of $0.1 million for natural gas.

Adjustment No. 6.08ER, 6.08GR - Incentive Pay

Consistent with prior general rate cases, 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, Exh. TMH-1T, explains why this expense is appropriate for recovery in rates.

For this calculation, PSE used the payouts that occurred in March for years 2016 through 2019, which related to calendar years 2015 through 2018. The incentive payment is allocated to O&M based on the distribution of wages. The four-year average of the payouts is allocated between electric and natural gas O&M using the direct labor allocator.

This restating adjustment increases net operating income for electric operations by $0.2 million and decreases net operating income for natural gas operations by $0.2 million.

Adjustment Nos. 6.09ER, 6.09EP, 6.09GR, 6.09GP - Excise Tax and Filing Fee

This restating adjustment adjusts the test year to actual expense for the Washington State excise tax and WUTC filing fee that should be recorded for these costs. The restating adjustments increase net operating income for both electric and natural gas operations by $0.1 million. As discussed in section III.A of my testimony, PSE is requesting to discontinue these rate making adjustments in future proceedings. Therefore, an equal and offsetting pro forma adjustment has been included that decreases net operating income for both electric and natural gas operations by $0.1 million.

Adjustment Nos. 6.10ER, 6.10EP, 6.10GR, 6.10GP - Directors and Officers ("D&O") Insurance

This adjustment is both a restating and pro forma adjustment. The restating adjustment removes the portion of D&O insurance that should be allocated to non-utility activity. This restating adjustment also annualizes the most current premiums, which became effective during the test year for D&O insurance. To allocate the restated insurance expense between utility and non-utility activity, PSE uses an allocation methodology evenly weighted between the 1) allocation of directors' fees and 2) allocation of covered employees' salaries. The total amount is then allocated to O&M expense in the same manner as the test year D&O insurance, which is based on where direct labor is charged. The restated D&O insurance applicable to O&M is then allocated between electric and natural gas operations based on the average number of customers allocator. This restating adjustment increases net operating income for electric operations by $5,301 and natural gas operations by $3,831. As discussed in section III.A of my testimony, PSE is requesting to discontinue these rate making adjustments in future proceedings. Therefore, an equal and offsetting pro forma adjustment has been included that decreases net operating income for electric operations by $5,301 and natural gas operations by $3,831.

Adjustment Nos. 6.11ER, 6.11GR Interest on Customer Deposits

This restating adjustment annualizes and allows recovery for the 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. Pursuant to WAC 480-90-113(9) and 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, which is 2.57 percent for 2019. This approach is consistent with prior general rate cases. The impact of this restating only adjustment decreases net operating income for electric operations by $0.8 million and for natural gas operations by $0.2 million.

Adjustment Nos. 6.12ER, 6.12GR - Rate Case Expenses

Consistent with prior rate cases, this restating adjustment uses the average of the last two power cost only rate cases (“PCORC”) and the last two general rate cases to determine a normalized level of expense. The average cost for a general rate case using this methodology is $2.2 million. This cost is allocated 50 percent to electric and 50 percent to natural gas, which results in a $ 1.1 million average cost for each energy group. The average cost for a power cost only rate case is $273,000.

The average costs for a general rate case are normalized for recovery over two years and the average costs of a power cost only rate case are normalized over four years. These normalized amounts are then compared to the amount PSE had actually recorded in the test year for each type of rate case expense.

This restating adjustment decreases net operating income for electric operations by $0.5 million and for natural gas operations by $0.4 million.

Adjustment Nos. 6.13ER, 6.13GR - Pension Plan

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

In PSE's 2009 and 2017 general rate cases, the Commission allowed and then affirmed that the actual four-year average of cash contributions ending with the historical test year should be used for setting rates. [3]

As determined by the plan actuary, PSE made tax deductible cash contributions totaling $78 million for the four-year period ending December 31, 2018. The four-year average of $19.5 million is allocated to O&M based on the distribution of

[3] Paragraph 80 in Order 11 in Dockets UE-090704 and UG-090705. Paragraph 177 in Order 08 in Dockets UE-170033 and UG-170034.

wages and then allocated between electric and natural gas based on the direct labor allocator.

This restating adjustment decreases net operating income for electric operations by $1.7 million and natural gas operations by $0.8 million.

Adjustment Nos. 6.14ER, 6.14EP, 6.14GR, 6.14GP - Property and Liability Insurance

This adjustment is both a restating and pro forma adjustment. The restating adjustment annualizes the most current property and liability insurance premiums, which became effective during the test year. Common property and liability insurance is allocated to electric and natural gas operations based on the non-production plant or number of customers' allocation factor. This restating adjustment increases net operating income for electric operations by $0.3 million and decreases net operating income for natural gas operations by $0.1 million.

The pro forma adjustment reflects the known and measurable premium increases for property and liability insurance expense based on premium renewals in April 2019. Further updates will be made to policies that will have new premiums during the course of the proceeding. Common property and liability insurance is allocated to electric and natural gas operations based on the non-production plant or number of customers' allocation factor. This pro forma adjustment decreases net operating income for electric operations by $0.4 million and decreases net operating income for natural gas operations by $24,481.

Adjustment Nos. 6.15ER, 6.15GR, 6.15EP, 6.15GP - Wage Increase

This is a restating and pro forma adjustment that reflects the impact of wage increases and payroll tax changes, as described in the Prefiled Direct Testimony of Thomas M. Hunt, Exh. TMH-1T. The restating adjustment annualizes the effect of the wage increases and payroll tax changes during the test year.

For represented (union) employees, the adjustment reflects the known annual wage increases that were granted in the approved contracts for the International Brotherhood of Electrical Workers ("IBEW") and United Association of Plumbers and Pipefitters ("UA") union employees. The contracted wage increase percentage for IBEW union employees is six percent through December 31, 2018, which is fully included in the test year. The contracted wage increases for UA union employees is three percent effective October 1, 2018.

The average wage increase used in the restating adjustment for non-union employees includes the known wage increase of three percent that was paid effective March 1, 2018. As in prior rate cases, this increase has been weighted by prior year actual salary increases. This is done to account for "slippage," as it is sometimes called, that occurs when new non-union employees are hired at lower salary rates than the more senior employees they are replacing.

This adjustment decreases net operating income for electric operations by $61,810 and for natural gas operations by $0.4 million.

The pro forma adjustment pro forms the impact of wage increases and payroll tax changes that occur after the test year and are also described in the Prefiled Direct Testimony of Thomas M. Hunt, Exh. TMH-1T.

For represented (union) employees, the adjustment reflects the known annual wage increases that were granted in the approved contracts for the IBEW and UA union employees. The contracted wage increase percentage for IBEW union employees is three percent effective January 1, 2019. The contracted wage increases for UA union employees is three percent effective October 1, 2019 and 2.75 percent effective October 1, 2020. This results in a compounded wage increase over the test year level of 5.83 percent.

The average wage increase used in the wage adjustment for non-union employees includes the known, declared wage increase of 3.5 percent effective March 1, 2019, plus an estimated 2.87[4] percent increase effective March 1, 2020. This results in a compounded wage increase over the test year levels of 3.83 percent for non-union employees after the application of slippage.

Q. What is the overall impact of the pro forma wage adjustment on net operating income?

A. The pro forma adjustment decreases net operating income for electric operations by $3.0 million and for natural gas operations by $1.9 million.

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4 The March 1, 2020 estimated increase of 2.87 percent is based on the same methodology used for bad debt expense, which is a three-year average based on five years of history after removing the highest and lowest year.

Q. Please explain how the non-union increases in the above wage adjustment were adjusted for slippage.

A. Slippage is determined by taking the ratio of 1) the change between the average annual wage at the beginning and end of each for the past four years to 2) the compounded declared wage increase declared during the same four-year period. This slippage ratio is then applied to the restated or pro forma declared wage increase percentage in order to calculate a weighted, or reduced, declared percentage increase that takes into account the actual change in annual salaries over time.

In order to perform the actual slippage calculation in this case, PSE first obtained the annualized payroll for all non-union employees as of March 1st for each of the last five years, which is the effective date of annual non-union salary adjustments. From this, PSE determined the average annual salary per non-union employee and calculated the actual percent increase in annual wages for the years 2014 to 2018 for restating and 2017 to 2020 for pro forma and compared this to the declared percent wage increase for non-union employees for those periods. Average salary change per non-union employees as of March 1 of each year for the restating and pro forma time periods covered by the slippage calculation are listed below in Table 3. The slippage percentage utilized for March 1, 2020 was determined by taking the annual declared increases, salaries and number of employees during the period March 1, 2015 through March 1, 2019 and determining the three-year average after removing the high and low amounts. This methodology follows how the normalized bad debt percentage is determined.

Table 5. Slippage Percentages for Restating and Pro forma Periods

March 1, 2015	2.91%
March 1, 2016	0.49%
March 1, 2017	1.47%
March 1, 2018	-2.48%
March 1, 2019	6.97%
March 1, 2020	1.62%

The above slippage percentages result in a compound average salary increase over the restating period of .58 percent and over the pro forma period of 1.89 percent. This was compared to the average declared wage increase granted and projected (for 2020) for non-union employees during those same years as shown in Table 6 below.

Table 6. Declared Wage Increases for Restating and Pro forma Periods

March 1, 2015	2.86%
March 1, 2016	2.91%
March 1, 2017	2.85%
March 1, 2018	3.00%
March 1, 2019	3.50%
March 1, 2020	2.87%

The above declared wage increase percentages result in a compound percentage increase over the restating period of 3.04 percent and over the pro forma period of 3.20 percent.

Accordingly, for the restating period the slippage percentage is 19 percent (.58% ÷ 3.04%) and for the pro forma period, the slippage percentage is 59% (1.89% ÷ 3.20%). The restating slippage percentage of 19 percent is applied to the restating declared wage increase of 0.50 percent[5] to yield the 0.10 percent wage increase percentage utilized in the restating adjustment. The pro forma slippage percentage of 59 percent is applied to the pro forma declared wage increase of 6.47 percent[6] to yield the 3.83 percent wage increase percentage utilized in the pro forma adjustment.

Q. What payroll taxes were included in the above wage adjustment?

A. The payroll taxes included in the adjustment are Social Security (Federal Insurance Contribution Act or "FICA"), Medicare, Federal Unemployment Tax ("FUTA"), and State Unemployment Tax ("SUTA"). PSE's costs have not changed due to the Washington Paid Family and Medical Leave law as PSE was able to have its short-term disability program approved as a voluntary Paid Medical Plan. And, for the Paid Family Plan, employees pay 100 percent of the cost per the state law.

Q. How were the payroll taxes for the above wage adjustment calculated?

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

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5 The stated wage increase of 3.00% effective March 2018 for two months not included in the test year (3.00% ÷ 12 x 2).

6 The stated wage increases of 3.50% and 2.87% effective March 1, 2019 and March 1, 2020 compounded.

Q. Would you please continue discussing the common adjustments?

A. Yes. The next common adjustment is:

Adjustment Nos. 6.16ER, 6.16GR, 6.16EP, 6.16GP - Investment Plan

This is a restating and pro forma adjustment. The restating adjustment adjusts the PSE portion of investment plan expense to reflect the annualized expense associated with the wage increases during the test year and is based on the current employee contribution rates. This adjustment decreases net operating income for electric operations by $13,157 and for natural gas operations by $4,190.

The pro forma adjustment adjusts the PSE portion of investment plan expense to reflect the additional expense associated with the pro forma wage increases and is based on the current employee contribution rates. This adjustment decreases net operating income for electric operations by $0.2 million and for natural gas operations by $0.1 million.

Adjustment Nos. 6.17ER, 6.17GR, 6.17EP, 6.17GP - Employee Insurance

Please see the Prefiled Direct Testimony of Thomas M. Hunt, Exh. TMH-1T, for a detailed description of PSE's employee benefits. This is both a restating and pro forma adjustment. The restating adjustment annualizes the effect of the benefit cost increases during the test year. PSE's benefit costs included in this adjustment are Long Term Disability, Basic Life Insurance and Wellness Credits. These costs are allocated to O&M based on the distribution of wages during the test year and then to electric and natural gas based on the direct labor allocator. The effect of the restating adjustment is to decrease net operating income for electric operations by $23,850 and for natural gas operations by $10,645.

The pro forma adjustment adjusts the test year employee benefits expense to the most current average cost per participant based on the 2018 participant count times the average cost as of February 2019. As the average benefits cost is subject to change, PSE will be updating these costs during the course of this proceeding. The effect of the pro forma adjustment is to decrease net operating income for electric operations by $0.7 million and for natural gas operations by $0.3 million.

Adjustment No. 6.18ER, 6.18GR – AMA to EOP Rate Base

As discussed earlier in my testimony, PSE's test year rate base was developed using historical AMA balances for the 13 months ended December 31, 2018. This restating only adjustment adjusts the average net plant in service balances to actual EOP balances as of December 31, 2018.

Q. Why is the use of EOP rate base appropriate in this GRC?

A. The use of EOP rate base is a tool the Commission continues to recognize as a useful means to address regulatory lag. EOP rate base requires no estimates or projections and instead is based on the actual plant values that are in service and providing benefits to customers at the end of the test year. Reflecting rate base at EOP values provides a more representative picture of the plant and associated depreciation expense in place during the rate effective period; in contrast, the use of AMA balances for rate base requires the plant to have been in place prior to the start of the test year in order for the investment to be fully reflected in rates.

Q. Has the Commission supported the use of EOP rate base?

A. Yes. In Order 08 in Dockets UE-111048 and UG-111049, the Commission stated that it is open to measuring rate base "at the end, or subsequent to the end of the test-year rather than the test-year average."[7] Subsequently, the Commission allowed the use of EOP rate base as a means to address regulatory lag in: PSE's 2013 expedited rate filing, Dockets UE-130137 and UG-130138; Pacific Power and Light's 2013 general rate case, Docket UE-130043; and most recently Avista's 2017 general rate case, Dockets UE-170485 and UG-170486.[8] Furthermore, in PSE's 2017 general rate case, the Commission reiterated that EOP rate base was among the tools the Commission has adopted to avoid the 27 month regulatory lag that often occurs through traditional AMA historical ratemaking.[9]

Q. Why is the use of EOP rate base appropriate for PSE in this proceeding?

A. As is discussed by multiple witnesses, PSE is experiencing significant regulatory lag related to its ongoing capital investment in its traditional pipes and wires business and most notably in its information technology ("IT") infrastructure. The use of EOP rate base in this proceeding will partially address the direct cause of the regulatory lag.

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7 *See WUTC v. PSE,* Dockets UE-111048 & UG-111049, Order 08 ¶ 491 (May 7, 2011).

8 *See WUTC v. Avista*, Dockets UE-170485 & UG-170486, Order 07 ¶ 203 (Apr. 26, 2018).

9 *See WUTC v. PSE,* Dockets UE-170033 & UG-170034, Order 08 ¶ 326 (Dec. 5, 2017).

Q. Are increased customer growth and achieved savings expected to offset PSE's needed level of future investment?

A. No. The earnings erosion that PSE is currently experiencing is not a temporary matter. For the foreseeable future, PSE must continue to invest in both its IT and transmission and distribution infrastructure to maintain the security, safety, and reliability of these systems. Absent rate relief, PSE will see its earnings continue to erode. Exhibit SEF-10 provides a comparison of the five-year compound growth rate for O&M, depreciation and amortization expenses and customer counts for the 2013 through 2018 period. This information clearly demonstrates that the growth in customers does not offset the growth in depreciation and amortization expenses.

Q. How does end of period rate base help to address PSE's demonstrated earnings erosion?

A. As discussed earlier, end of period rate base will partially address earnings erosion as it shortens the time frame between when the investment has been placed in service and when the investment is included in rates. Investments recovered in a general rate case on an AMA basis can have up to 27 months of lag. Additionally, investments made during the general rate case test year are only partially included in rates, due to the effects of the AMA convention. Use of end of period rate base still results in regulatory lag, but the lag is shorter—between fourteen and twenty months, depending on the month the investment was made.

Q. How does the increased spending in technology investments affect the earnings erosion and further support the use of end of period rate base?

A. As discussed in Ms. Hopkins' testimony, as utilities continue to rely more on technology solutions to meet evolving customer needs and growing security risks, IT assets have become as fundamental to the provision of utility service as the classic pipes and wire infrastructure investments. Security and reliability of the IT systems are critical and of growing importance in this day of increased cyber-security threats as well as the NERC/CIP[10] compliance requirements. However, the regulatory lag associated with these assets has a far greater impact on earnings erosion than the typical transmission and distribution ("T&D") expenditures, due to the shorter lives of the IT assets and the associated impact on PSE's depreciation and amortization expenses. The typical T&D investment life ranges between 30 to 50 years, which means the annual depreciation on those assets range between two and three percent per year. However, technology investments typically have a depreciable life of ten years or less and in many circumstances only a three to five-year life. Therefore, the impact of the typical 27-month regulatory lag is far greater on these short-lived assets and creates significant earnings erosion if not addressed. To illustrate the issue, Table 7 provides a comparison of the under-recovery of depreciation expense associated with a $1 million investment.

[10] North American Electric Reliability Corporation-Critical Infrastructure Protection.

Table 7. Demonstration of Lag on $1 Million Investment

	T&D Asset	IT Asset
Asset Life	30 yrs	5 yrs
Annual Depn Rate	3%	20%
Annual Depn expense impact	$33,333	$200,000
Depreciation Exp. incurred but not recovered in rates:		
Traditional AMA (27 months)	$75,000	$450,000
EOP Rate base	$41,667	$250,000
% of delayed or lost recovery		
Traditional AMA	8%	45%
EOP rate base	4%	25%

As can be seen in Table 7, under traditional ratemaking, where there is typically a minimum 27-month lag, the recovery delayed or lost through regulatory lag is approximately eight percent for a T&D investment; however, in the case of a technology related asset with a five-year depreciable life, the recovery delayed or lost through regulatory lag is approximately 45 percent. The delay or loss through regulatory lag for a technology-related asset is six times greater than for a T&D investment. Table 7 shows that even utilizing end of period rate base in a general rate case, there is delayed or lost recovery of 25 percent of the technology related asset.

Q. Please explain the adjustment.

A. The adjustment adjusts rate base and working capital from an AMA basis in the test year results to an EOP basis utilizing the same account treatment as was used in Adjustments 5.01E/5.01G, 5.02E/5.02G and 7.03ER with the only difference being the amounts used for the calculation were December 31, 2018 EOP balances instead of AMA. The resulting adjustment is an increase to electric rate base of $182.8 million and an increase to natural gas rate base of $150.7 million.

Q. Is there another adjustment that is appropriate when EOP rate base is used?

A. Yes. The following is the EOP restating adjustment that adjusts depreciation expense from an AMA basis to an EOP basis.

Adjustment No. 6.19ER, 6.19GR – AMA to EOP Depreciation

The adjustment restates depreciation expense as if the end of period balances were in effect for the entire test period. There are five categories of depreciable assets that are included in this adjustment based on the depreciation methodology from the depreciation study in PSE's 2017 general rate case and the limited depreciation study in this case. The five categories are: 1) Standard, 2) Not Studied, 3) End of Life, 4) Underlying Asset and 5) Retired End of Life. Each of these categories is described in Table 8 below along with the methodologies used to calculate the adjustment to depreciation expense for purposes of determining EOP expense.

Table 8. Summary of Methodologies Used to Adjust Depreciation Expense

Type	Treatment	Justification
Standard	December 2018 balance x depreciation rate in effect each month of the restating period	These accounts were studied in the 2017 general rate case and so standard treatment can be used when determining end of period depreciation expense.
Not Studied (includes ARC Depreciation and ARO Accretion)	December 2018 depreciation expense is used for each month of the restating period	An end of period adjustment recognizes the change in the depreciable balance over the restating period. But since this category of assets was not studied, in the 2017 general rate case, no change in depreciation rates occurred and so using December's depreciation amount uses the most current expense.
End of Life	No EOP adjustment is made for this category of depreciation	The depreciation for this class of assets is based on the NBV of the assets amortized to a set termination date. The NBV is based on a static depreciable base value. Therefore, an EOP adjustment is not warranted.
Retired End of Life	December 2018 depreciation expense is used for each month of the restating period	Assets relate to unrecovered reserves from the 2017 general rate case study which have been fully amortized.
Underlying Asset	December 2018 depreciation expense is used for each month of the restating period	Treated the same as not studied as it is related to ARC Depreciation and ARO Accretion

The restating adjustment results in a decrease to net operating income of $16.9 million for electric and $9.7 million for natural gas. Additionally, to recognize the full impact of the increases in depreciation expense on the EOP accumulated depreciation, PSE increased the balance of accumulated depreciation by the respective increases in depreciation expense. Finally, the change to book depreciation expense necessitates a change to deferred taxes, which are decreased by 21 percent of the change to accumulated depreciation. For electric operations the impact on rate base of this adjustment is a decrease of $16.9 million. For natural gas operations the impact on rate base of this adjustment is a decrease of $9.7 million.

Q. Would you please continue discussing the common adjustments?

A. Yes. The next common adjustment is:

Adjustment Nos. 6.20EP, 6.20GP - Deferred Gains/Losses on Property Sales

The amortization of deferred gains and losses can sometimes require an annualizing restating adjustment if newly granted amortizations are not fully reflected in a given test year. During the current test year, however, no annualizing restating adjustment is necessary as a full year of amortizations from Dockets UE-170033 and UG-170034 have been reflected in the test year. Accordingly, this adjustment is a pro forma adjustment only with the purpose of providing customers the gains and losses from sales of utility real property completed since the last general rate case. The gains and losses are allocated between electric and natural gas based on the use of the property and amortized over three years. The pro forma adjustment decreases net operating income for electric operations by $0.4 million. For natural gas operations, the adjustment increases net operating income by $0.1 million

Adjustment Nos. 6.21EP, 6.21GP - Environmental Remediation

The amortization of environmental deferrals could potentially require an annualizing restating adjustment if newly granted amortizations are not fully reflected in a given test year. During the current test year, however, no annualizing restating adjustment is necessary as a full year of amortizations from Dockets UE-170033 and UG-170034 have been reflected in the test year. This pro forma only adjustment amortizes over five years the outstanding environmental remediation costs that have been deferred since September 2016, which is the end of the test year in PSE's prior general rate case. This adjustment also amortizes over five years a corresponding amount of the third party and insurance proceeds, either directly assigned or pro-rated, that are deferred as of December 31, 2018. This adjustment follows the draft allocation methodology that has been developed in collaboration with Commission Staff.

Q. Please provide an update on the process that PSE and Commission Staff have been engaged in to develop a methodology for allocating third party and insurance proceeds for environmental remediation accounts.

A. In paragraph 54 of the multiparty settlement agreement in Dockets UE-170033 and UG-170034, it was agreed that PSE and Commission Staff would commence a process to determine a methodology for assigning third party and insurance recoveries ("proceeds") for environmental remediation received by PSE, and this process was to commence by March 15, 2018. PSE and Commission Staff fulfilled this requirement with their first meeting on the environmental remediation assignment methodology, which was held on February 13, 2018. Additionally, in the multiparty settlement agreement, PSE agreed to update the Commission on the process. PSE provided an update in its 2018 expedited rate filing in Dockets UE-180899 and UG-180900.

PSE and Commission Staff have developed a draft methodology addressing how proceeds should be treated, which bases the treatment of proceeds on the type of proceeds received and the type of deferral being offset. It segregates deferrals into three categories:

- Additional costs associated with projects previously reviewed and approved for amortization in Dockets UE-170033 and UG-170034;
- New projects whose costs would have been covered by legacy policies that comprised the unassigned recoveries that existed and were reviewed in Dockets UE-170033 and UG-170034; and
- New projects that cannot be tied to prior recoveries that may or may not have new recoveries specific to the project.

The draft methodology also indicates that treatment of any other unassigned recoveries that were not assessed in the 2017 general rate case and that are not connected to a specific site will be determined in a future proceeding. PSE has no such recoveries in this proceeding.

The portion of non-direct unassigned recoveries that were applied against all new cost deferrals since September 30, 2016 was determined pursuant to the 2017 general rate case and the draft methodology by taking the actual deferred costs as of December 31, 2018 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.

The impact of this annualizing adjustment decreases net operating income by $0.1 million for electric operations and by $0.7 million for natural gas operations.

Q. Would you please continue discussing the common adjustments?

A. Yes. The next common adjustment is:

Adjustment Nos. 6.22EP, 6.22GP – Advanced Metering Infrastructure ("AMI")

Installation of PSE's advanced metering infrastructure began in 2016 under a strategy explained in the Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T. AMI provides a communication network and metering equipment in PSE's electric and natural gas service territory that will eventually replace its existing Automated Meter Reading ("AMR") system. This pro forma adjustment is comprised of the following three components:

1. The rate year amortization of the deferral of the return on AMI plant in service between October 2016 through June 2018 that was allowed as part of the settlement agreement in PSE's 2018 ERF, Dockets UE-180899 and UG-180900;

2. The rate year amortization of the deferral of the depreciation of current AMI plant that was allowed as part of the settlement agreement in PSE's 2018 ERF; and

3. The rate year depreciation expense and AMA rate base for AMI pro forma plant additions occurring after the end of the test year through June 30, 2019.

Q. Please explain the deferral of the return on AMI investment.

A. Per the 2018 ERF settlement agreement, settling parties agreed that beginning March 2019, PSE could defer for consideration in this proceeding, the return on the $60.5 million of AMI investment that was in service in the ERF test year, June 30, 2018, at 7.49 percent. PSE was not authorized to defer the return on any investment occurring after June 2018. The Commission approved the settlement. PSE believe it is appropriate to allow recovery of this deferred balance because the deferred return is associated with assets that were in service as of June 30, 2018, the end of the ERF test year and were providing benefits to customers.

PSE has calculated the monthly deferred return through April 2020, up to the start of the rate year in this proceeding, based on the declining balance of the June 2018 AMI plant in service. The amortization period requested for this deferral is three years and the resulting amounts are shown on Line 18 of adjustments 6.22EP and 6.22GP.

Q. Please explain the deferral of depreciation expense on AMI investment.

A. The 2018 ERF settlement agreement also allowed PSE to defer, beginning March 2019, the depreciation expense on all AMI investment. PSE is only including in this part of the adjustment the depreciation expense for AMI plant in service through June 2019. PSE will continue to defer depreciation on plant in service from July 2019 forward for consideration in a future rate proceeding. The adjustment includes actual depreciation expense on actual AMI investment in March 2019 and a monthly forecast of depreciation expense for April through June that includes plant in service for those months. PSE will update the April through June estimates to actual amounts during the course of this proceeding. The June 2019 monthly depreciation expense is then accumulated through April 2020, up to the beginning of the rate year in this proceeding. Included in the deferral is an offset or reduction to depreciation expense for avoided depreciation resulting from the retirement of automatic meter reading ("AMR") equipment during the same time period. The net deferred expense is amortized over three years and presented on line 19 of adjustments 6.22EP and 6.22GP. Additionally, the rate year AMA of the deferral balance is included in rate base as shown on lines 8 through 11 of the adjustment. Inclusion in rate base is consistent with treatment of other deferrals.

Q. Please explain the pro forma plant portion of the adjustment.

A. Lines 3 through 6 of Adjustment 6.22EP and 6.22GP reflect the rate year AMA balances of ~~the same underlying plant investment as is included in the depreciation deferral adjustment~~plant investment made from January through March of 2019 and forecasted amounts from April through June of 2019. Deferred taxes associated with the tax depreciation of the project were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). Associated AMI depreciation expense net of the avoided AMR depreciation are presented on lines 16 and 17 of this adjustment. By limiting the pro forma adjustments used for the depreciation deferral and for the pro forma plant adjustment to June 2019, PSE is requesting known and measurable amounts that have been offset by the benefit of the avoided depreciation on the AMR investment. Also, the estimated costs can be trued up in PSE's supplemental or rebuttal filing. Additionally, because the return and depreciation deferrals are covering the periods leading up to the rate year and the pro forma plant adjustment is for the rate year, there is no double counting of the investment included in this adjustment.

This pro forma adjustment decreases net operating income for electric operations by $4.9 million and for natural gas operations by $2.1 million. The adjustment also increases rate base for electric operations by $28.2 million and for natural gas operations by $13.9 million.

Q. Would you please continue discussing the common adjustments?

A. Yes. The next common adjustment is:

Adjustment Nos. 6.23ER, 6.23EP, 6.23GR, 6.23GP –Rent Expense

Please see the Prefiled Direct Testimony of Douglas S. Loreen, Exh. DSL-1T for a detailed description of the changes to PSE's rent profile. This is a restating and pro forming adjustment intended to provide transparency for the impact of the change in PSE's rent costs in the rate year. The restating adjustment annualizes rents and operating expenses, tenant improvement amortizations, and sub-leasing revenues associated with the vacated PSE building. The adjustment pro forms the annualized base rents, operating expenses, and tenant improvement amortizations in the Bellevue EST Building and the Bothell campus expansions.

Furthermore, PSE will be closing service offices in 2019 for the Oak Harbor, Bellingham, Ellensburg, and South Whidbey (Freeland) offices. Rent and operating expenses are removed from the test year as part of the pro forming adjustment.

PSE owns land and buildings at the Vernell location, which is discussed in Mr. Loreen's testimony. These assets are already included in test year rate base and require no further adjustment. The restating adjustment removes Vernell leasing revenues, as the tenant vacated the property during the test year.

The restating adjustment increases net operating income for electric operations by $0.3 million and for natural gas operations by $0.5 million. The pro forma adjustment increases net operating income for electric operations by $0.4 million and for natural gas operations by $0.1 million.

Adjustment Nos. 6.24EP, 6.24GP – Get To Zero

Q. What are the Get To Zero ("GTZ") projects?

A. As discussed in the Prefiled Direct Testimony of Mr. Josh J. Jacobs, Exh. JJJ-1T, the GTZ projects comprise a customer-focused initiative to expand self-service options, remove obstacles for customers, provide proactive communication and quickly anticipate and solve problems for customers when they occur. The initiative includes several projects such as: a complete pse.com website refresh; a major update to the mobile app, which is available as an update to the myPSE outage app for Apple (iOS) and Google (Android) devices; integrated work management tools for Electric Meter Operations and Meter Network Services; additional enhancements to the Integrated Voice Response ("IVR") automated phone system; and further improvements to PSE's billing, payment, credit and collections processes.

Q. Please explain the adjustment for GTZ.

A. This pro forma adjustment includes the post-test year investment for the GTZ projects, based on actual costs through March 2019 and estimated costs for the projects through June 2019, which can be trued up in PSE's supplemental or rebuttal filing.

The AMA plant balance was calculated for the rate year. The depreciation expense was calculated monthly, and the resulting monthly-accumulated depreciation was then averaged in the same manner as the project cost. Deferred taxes associated with the tax depreciation of the projects were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h).

In Dockets UE-190274 and UG-190275, PSE has a pending accounting petition associated with deferral of depreciation expense beginning May 2019 for GTZ assets placed in service after the test year in PSE's ERF proceeding. At the time of this filing, the Commission has not yet considered PSE's accounting petition. However, considering the length of a general rate case proceeding, it is reasonable and appropriate to include an adjustment in this case in the event the accounting petition is approved during the course of the case, so as not to allow the deferral to be outstanding for a great length of time. If the Commission denies PSE's accounting petition, this adjustment would no longer be necessary.

This adjustment includes the rate year amortization expense and rate base amount for deferred costs for the GTZ assets placed in service between July 2018 and June 2019. PSE will continue to defer depreciation for GTZ assets placed in service from July 2019 forward for consideration in a future rate proceeding. PSE is requesting a three-year amortization period from the date rates will become effective for this proceeding, May 1, 2020.

By limiting the pro forma adjustments used for the depreciation deferral and for the pro forma plant adjustment to June 2019, PSE will be requesting known and measurable amounts in this proceeding. Additionally, because the depreciation deferral is covering the period leading up to the rate year and the pro forma plant adjustment is for the rate year, there is no double counting of the investment included in this adjustment.

This pro forma adjustment decreases net operating income by $9.6 million for electric and by $4.9 million for natural gas. This pro forma adjustment also increases rate base by $25.9 million for electric and by $13.2 million for natural gas.

Q. Would you please continue discussing the common adjustments?

A. Yes. The next common adjustment is:

Adjustment Nos. 6.25EP, 6.25GP – Credit Card Payment Processing Fees

The amortization of credit card payment processing fee deferrals could potentially require an annualizing restating adjustment if newly granted amortizations are not fully reflected in a given test year. During the current test year, however, no annualizing restating adjustment is necessary as a full year of amortizations from Dockets UE-170033 and UG-170034 have been reflected in the test year.

This pro forma adjustment recalculates the three-year amortization, based on the final deferral amount of $3.8 million (versus the estimated deferral balance of $4.3 million utilized in the 2017 general rate case). Additionally, the amortization period included in the 2017 general rate case was three years and expires in

December 2020 part way through the rate year. Accordingly, this adjustment only includes the eight months of amortization expense that will exist in the rate year.

The result of this pro forma adjustment on net operating income is an increase of $0.5 million for electric operations and $0.3 million for natural gas operations.

Adjustment Nos. 6.26EP, 6.26GP – Unprotected DFIT Removal from Rate Base

As stated previously, the TCJA resulted in both protected and unprotected excess accumulated deferred income tax ("ADIT") assets and liabilities. Unprotected excess ADIT consists mainly of ADIT on non-plant related deferred assets and liabilities. The December 2017 ADIT balances that were determined using the historical 35 percent tax rate were revalued at the new lower corporate tax rate of 21 percent, resulting in excess ADIT balances to be returned to customers. Unlike the protected ADIT, the unprotected ADIT balances are not turning around. In the settlement agreement that was conditionally approved by the Commission in PSE's 2018 expedited rate filing in Dockets UE-180899 and UG-180900, the pass back of the unprotected ADIT was left to be determined in this general rate case. This pro forma adjustment reflects the amortization over a four-year period and the decrease in DFIT balances associated with passing back the unprotected DFIT balances. PSE is proposing a four-year period to act as an offset to the additional storm amortizations that are recovered over a four-year period. There is no tax effect on the amortization in order to gross it up for revenue requirement purposes. The rate base impact is determined by beginning amortization at the start of the rate year and pro forming the rate base amounts to their rate year AMA balances. This pro forma adjustment increases net operating income for electric operations by $9.0 million and increases net operating income for natural gas operations by $0.7 million. This pro forma adjustment also increases rate base by $4.5 million for electric operations and by $0.3 million for natural gas operations.

Adjustment Nos. 6.27EP, 6.27GP – Public Improvement

This pro forma adjustment adjusts rate base and operating costs for the Public Improvement program, which is explained in the Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T. The adjustment increases both electric and natural gas rate base for post-test year additions to plant placed in service during January – March of 2019, and for additions forecasted to be in service during April – June 2019 and can be trued up to actuals at PSE's supplemental or rebuttal filing and are net of the associated retirements during the same period. The adjustment calculates depreciation expense, accumulated depreciation, and deferred FIT based on the composite depreciation rates approved in the 2017 general rate case. Plant balances as of June 2019 are pro formed to their rate year AMA balances. Deferred taxes associated with the tax depreciation of the project were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). The impact of this pro forma adjustment is an increase in rate base of $12.9 million for electric and $6.0 million for natural gas. This pro forma adjustment also decreases net operating income by $0.3 million for electric and by $0.1 million for natural gas.

Adjustment Nos. 6.28EP, 6.28GP – Contract Escalations

This pro forma adjustment reflects the most recent negotiated contract escalation rates for outside services related to the following expense classifications; transmission, distribution, customer accounts, and administration and general. The calendar year 2019 escalation rates were applied on a pro forma basis to actual 2018 expense amounts for the contracted services referred to above. The impact of this adjustment is a decrease to net operating income of $1.3 million to electric operations and a decrease of $0.3 million to natural gas operations.

Adjustment Nos. 6.29EP, 6.29GP - HR Tops

This is a pro forma adjustment for the software HR TOPS with an estimated total cost of $10.3 million that will be in service by the end of June 2019, which can be trued up to actuals in PSE’s supplemental or rebuttal filing. The project is discussed in the Prefiled Direct Testimony of Margaret F. Hopkins, Exh. MFH-1T. The adjustment calculates depreciation expense, accumulated depreciation, and deferred FIT, which are pro formed to their rate year AMA balances. Deferred taxes associated with the tax depreciation of the project were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). The impact of this pro forma adjustment is an increase in rate base of $5.5 million for electric and $2.8 million for natural gas. This pro forma adjustment also decreases net operating income by $0.5 million for electric and by $0.3 million for natural gas

B. Exh. SEF-7 Electric Only Adjustments

Q. Please explain the electric only adjustments.

A. Explanations of the electric only adjustments are as follows:

Adjustment No. 7.01ER, 7.01EP - Power Costs

This adjustment is both a restating and pro forma adjustment. The restating adjustment found in column (c) of Adjustment 7.01ER is applied in the same manner as in a commission basis report and is intended to depict power costs under normal temperature and power supply conditions. Test year power costs are adjusted to recognize the changes in load and generation from test year levels summarized below. The following changes in load and generation are priced at the mid-C flat dollar per MWh embedded in rates that were in effect for the month being repriced.

1) the change in load used in the weather normalization adjustment (Adjustment No. 6.02ER), and

2) the adjustment to reflect hydro and wind volumes at normal levels based on levels assumed in the most recent general rate case as they are also impacted by weather.

Additionally, the following non-weather adjustments to power costs were made consistent with PSE's established commission basis reporting:

1) A GAAP only non-settled fuel valuation for gas for power storage is removed as the true amount recorded as power costs for fuel is valued at the time the inventory is used and is not valued at the financial statement date.

2) True-ups made in 2018, which were related to the one-time fixed production cost deferral in place during 2017, were removed.

3) An adjustment is required for the equity component of the TransAlta Centralia Coal Transition Power Purchase Agreement ("PPA") approved by the Commission in Docket UE-121373. This adjustment is necessary to make actual booked expenses, which do not include regulatory adjustments, match the recovery built into rates.

Overall, this restating adjustment decreases net operating income for electric operations by $7.6 million.

The pro forma adjustment, lines two through nine, represent the power costs that are projected to be incurred during the rate year. The calculation of rate year projected power costs is explained in the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-1CT. The change in power costs between the 2017 GRC rate effective date of December 18, 2017, and the current proceeding, are shown in Exh. PKW-3C and in more detail in Exh. PKW-13C.

Line 13 represents the production operations and maintenance costs ("production O&M") presented by Mr. Ronald J. Roberts in Exh. RJR-5.

Line 14 presents the transmission expenses that are related to the Third AC, Northern Intertie and Colstrip transmission lines. This category of costs is left at its historical test year level and requires no adjustment.

Line 15 presents revenues associated with variable transmission earned under PSE's Open Access Transmission Tariff ("OATT"). Consistent with the 2017 general rate case, the variable transmission revenues included in this adjustment are calculated by re-pricing the most recent three-year average of transmission volumes across the respective lines at the most current OATT tariff rate. During 2016, a 193 MW reservation by Powerex on the Northern Intertie was not renewed. Therefore, to accommodate for this known and measurable change, the average of the volumes from 2017 and 2018 associated with the Northern Intertie revenues were used; the 2016 transmission volumes associated with the Northern Intertie were not included. New OATT rates under the formula rate will be finalized by June 3, 2019 and their impact on this adjustment will be included when power costs are updated during the course of this proceeding.

Finally, the amount of the Coal Transition PPA between PSE and TransAlta Centralia Generation LLC, discussed above, does not change in the rate year but like the other variable production related energy costs, a production factor is applied to it. These pro forming adjustments represent an increase to restated net operating income of $3.3 million.

Q. Do you have any further explanations with respect to the power costs in Adjustment 7.01?

A. Yes. As power costs and O&M costs are also included in other adjustments, it is necessary to reduce the total power cost adjustment by these amounts to avoid a double count in the revenue requirement. Page 2 of Adjustment 7.01[11], provides these adjustments and presents a reconciliation of the rate year projections included in the testimonies of Mr. Wetherbee and Mr. Roberts, to the final adjusted rate year power cost and O&M projections included in Adjustment 7.01. Specifically, test year benefits and taxes are re-classified out of Mr. Wetherbee's power cost total and Mr. Roberts' production O&M total and reflected separately

[11] Page 2 of 11 of Exh. SEF-7.

on lines 15a and 15d on page 1 of the PCA/Fixed Production baseline rate shown in Exh. SEF-11. The rate year power costs excluding the benefits and taxes have been adjusted to test year power cost levels by the appropriate production factor discussed later in my testimony and are the amounts reflected in Adjustment 7.01.

Q. Will you update the PCA mechanism's baseline rate in this proceeding?

A. Yes. PSE will update the PCA mechanism baseline rate later in this proceeding to reflect the most current information available. The schedule, shown in Exh. SEF-11, presents the PCA baseline rate based on all fixed production and variable power costs included in the adjusted results of operations in this filing. PSE requests approval of this baseline rate as it is utilized for purposes of determining the imbalance for sharing under PSE's PCA mechanism as well as used for setting amounts in PSE's decoupling mechanism.

Q. Please continue with your discussion of the adjustments.

A. The following are additional electric only adjustments.

Adjustment No. 7.02ER, 7.02EP - Montana Electric Tax

This restating adjustment adjusts the test year amount of Wholesale Energy Transaction Tax ("WET") and Electricity and Electrical Energy License Tax ("EEL") to the amount that is related to the Colstrip generation included in the restating power cost adjustment (Adjustment 7.201ER). The fuel and operating and maintenance costs associated with this generation are reflected in the power cost adjustment. This restating adjustment decreases net operating income for electric operations by $0.1 million.

The pro forming adjustment adjusts the restated taxes to the amount that is projected to be incurred during the rate year based on the power generated at Colstrip at the current tax structure. This pro forma adjustment increases net operating income for electric operations by $0.5 million.

Adjustment No. 7.03ER - Wild Horse Solar

This restating adjustment removes the effects of the solar project at PSE's Wild Horse wind facility. This power project is a demonstration project and PSE is not requesting recovery of the costs associated with it at this time. This restating adjustment increases net operating income for electric operations by $0.2 million and decreases rate base by $1.6 million.

Adjustment No. 7.04ER - ASC 815

This restating adjustment removes the effect of Accounting Standards Codification 815, which represents mark-to-market gains or losses recognized for derivative transactions. This accounting pronouncement is not considered for rate making purposes. This adjustment decreases net operating income for electric operations by $32.9 million.

Adjustment No. 7.05ER, 7.05EP - Storm Damage

This restating and pro forma adjustment adjusts the test year expense level of storm damage expense of $10.3 million to the normalized level of storm damage expense, based on the average of the most recent six years as has been done in prior general rate cases. In his testimony, Mr. King discusses an error in the test year that was made related to normal and deferred storm expense. Under the terms of the 2017 general rate case multiparty settlement agreement, PSE's storm deferral mechanism has a cumulative annual cost threshold of $10 million for deferral of qualifying storms and qualifying events, and storms with a total qualifying cost less than $500,000 do not qualify for deferral and are not counted toward the threshold. A qualifying storm event occurred on January 27, 2018 and the $447,000 cost of this event was below the $500,000 floor for deferral. However, the costs for this event was inadvertently included in the $10 million threshold calculation used to determine the amount of qualifying storm costs to defer. Thus, in 2018, PSE over deferred and under expensed storm costs by $447,000. To accommodate for this error, even though it was not recorded on the books in the test year, this adjustment includes the $447,000 in 2018 for the calculation of the six year average of normal storm expense. By doing so, the correction of the error is incorporated into the restating adjustment when the six year average normal storm amount that includes the $447,000 is compared to the test year normal storm expenses that do not include the $447,000. This restating adjustment decreases net operating income for electric operations by $11,001.

The amortization of storm deferrals could potentially require an annualizing restating adjustment if newly granted amortizations are not fully reflected in a given test year. During the current test year, however, no annualizing restating adjustment is necessary as a full year of amortizations from Dockets UE-170033 and UG-170034 have been reflected in the test year. The pro forma adjustment for storm calculates the impact on amortization of new storm deferral balances that have not been previously approved. At the time of preparing this, PSE had storm deferral balances for nine storm events that have not previously been approved totaling $54.1 million[12].These storms are discussed in the Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T. The last two storm events occurred in February 2019, so all qualifying costs are now known and deferred. This adjustment will be updated during the course of this proceeding to add additional qualifying storm events should they occur. The impact of this annualizing adjustment on electric operations is a decrease to net operating income of $10.7 million.

Adjustment No. 7.06EP - Regulatory Assets and Liabilities

The amortization of new regulatory assets and liabilities could potentially require an annualizing restating adjustment if newly granted amortizations are not fully reflected in a given test year. During the current test year, however, no annualizing restating adjustment is necessary as a full year of amortizations from Dockets UE-170033 and UG-170034 have been reflected in the test year.

This pro forma adjustment adjusts all production related regulatory assets and liabilities that were previously recovered through the PCA mechanism to their rate year amounts. The amortization of power costs related to regulatory assets and liabilities are considered variable costs and have been adjusted in Adjustment 7.01EP. The remaining amortization for regulatory assets and liabilities not related to power costs are considered fixed costs and are included in PSE's electric decoupling mechanism. As a result, although the rate base section of this

[12] The January 27, 2018 storm event discussed above is not included in these nine events.

adjustment reflects the AMA of the rate year for both power cost *and* non-power cost regulatory assets and liabilities, only the *non-power cost* regulatory asset and liability amortization for the rate year is reflected in this adjustment. The regulatory assets and liabilities for which amortization expires part way through the rate year only include amortization for the applicable months during the rate year. Additionally, regulatory assets and liabilities that have deferred taxes will also have excess deferred income taxes, the handling of which is included in Adjustment 6.26EP Amortization of Unprotected Deferred Taxes. The overall impact of this adjustment is an increase to electric net operating income of $9.1 million and a decrease to rate base of $23.4 million.

Adjustment No. 7.07ER – Colstrip Depreciation

This restating adjustment calculates the impact of implementing the limited depreciation study update discussed in the Prefiled Direct Testimony of John J. Spanos, Exh. JJS-1T for Colstrip Units 3 and 4. Mr. Spanos conducted a full depreciation study in PSE's 2017 general rate case. In this case, PSE hired Mr. Spanos and his firm, Gannett Fleming, Inc., to evaluate PSE's depreciation rates for Colstrip Units 3 and 4 in light of the recently passed Washington Clean Energy Transformation Act discussed in the Prefiled Direct Testimony of Mr. David E. Mills, Exh. DEM-1T. The Prefiled Direct Testimony of John J. Spanos, Exh. JJS-1T, provides an update to the current depreciation rates to ensure that the Colstrip Units 3 and 4 assets will be fully depreciated by December 31, 2025, as required by the new law. Additionally, this adjustment removes the restated level of depreciation expense for Colstrip Units 1 and 2 consistent with the discussion of these plants in the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1CT.

To adjust the test year depreciation expense to the new depreciation rates, PSE used the relationship of the new depreciation rate for each specific asset account to the old depreciation rate for that account multiplied by the restated depreciation expense for that particular account. The results of this calculation for all asset accounts for Colstrip Units 3 and 4 were then totaled and compared to the total restated depreciation expense for the test period for those units that is included in Adjustment 6.19ER with the difference between the two being the adjustment.

The full impact of the depreciation adjustment was used to adjust rate base in recognition that accumulated depreciation is on an end of period basis. Finally, based on the Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T, the treatment of the EDIT reversals must be consistent with the treatment of depreciation expense and rate base. Because depreciation expense for Colstrip Units 1 and 2 is being removed, the ARAM for Colstrip Units 1 and 2 in the amount of $2.2 million is also removed on line 6. For Colstrip Units 3 and 4, the specific tax rate including ARAM that is specific to Colstrip Units 3 and 4 was used to tax effect the adjustments to depreciation expense and ADIT. This restating adjustment increases net operating income by $1.7 million and decreases rate base by $11.0 million.

Adjustment No. 7.08EP - Energy Imbalance Market

This pro forma adjustment removes the rate base, operating costs and amortization associated with PSE's participation in the Energy Imbalance Market ("EIM"). As discussed in the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-1CT, in PSE's 2017 general rate case, parties agreed to exclude the EIM benefits and the related EIM fixed costs from the settled revenue requirement and that both would be included in PSE's PCA mechanism imbalance calculation. Consistent with Staff's recommendation in the 2017 general rate case, because EIM benefits are not known and measurable, PSE is removing the EIM associated capital and operating costs from the revenue requirement and will continue to include the fixed costs in the PCA imbalance calculation to be matched with the actual EIM benefits as they occur. The impact of this pro forma adjustment is an increase in electric net operating income of $4.5 million and a decrease to electric rate base of $3.3 million.

Adjustment No. 7.09EP – High Molecular Weight Cable Replacement

This pro forma adjustment adjusts rate base and operating costs for the High Molecular Weight Cable Replacement program, which is explained in the Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T. The adjustment increases electric rate base for post-test year additions to plant placed in service January through March of 2019, and for additions forecasted to be in service April through June 2019, net of the associated retirements during the same period. The April through June 2019 estimates will be trued up to actuals during the course of this case. The adjustment calculates depreciation expense, accumulated depreciation, and deferred FIT based on the depreciation rates approved in the 2017 general rate case. Plant balances as of June 2019 are pro formed to their rate year AMA balances. Deferred taxes associated with the tax depreciation of the project were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). This pro forma adjustment decreases electric net operating income by $0.3 million and increases electric rate base by $11.9 million.

Adjustment No. 7.10EP – Energy Management System

This pro forma adjustment relates to the Energy Management System ("EMS") upgrade discussed by Ms. Hopkins. The EMS upgrade project went into service in January 2019 and this adjustment pro forms rate base to rate year AMA for this project. The depreciation expense was calculated monthly, and the resulting monthly-accumulated depreciation was then averaged in the same manner as the project cost. Deferred taxes associated with the tax depreciation of the projects were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). This adjustment increases rate base by $4.4 million and decreases net operating income by $2.4 million.

C. Exh. SEF-8 Natural Gas Only Adjustments

Q. Please explain the natural gas only adjustments.

A. Based on paragraph 70 of the Commission policy statement in Docket UG-120715, PSE must transfer its investment that has been approved for recovery in its gas Cost Recovery Mechanism ("CRM") into base rates. The first time PSE transferred investment from its CRM into base rates was in its 2017 general rate case. The transfer of the recovery of assets from the CRM to base rates and the resulting rate case adjustment in this filing follows the same methodology that was used in the 2017 general rate case. Table 9 presents the CRM filings and supporting Pipeline Replacement Program Plan (“PRPP”) filings that are relevant in this case.

Table 9. CRM Investment

CRM Program Year	CRM Docket Number	Supporting PRPP	Total Investment	Treatment
Nov 2016 - Oct 2017	UG-170692	PG-160294	$45,517,704	Transfer to Base Rates
Nov 2017 - Oct 2018	UG-180514	PG-170693	$60,284,764	Transfer to Base Rates
Nov 2018 - Oct 2019	UG-190464	PG-170693	$9,377,979	Leave in Schedule 149

Consistent with the method used in the 2017 general rate case, in order to achieve the transfer described above, the following steps were performed.

1. Include a general rate case adjustment to pro form the 2016/2017 and 2017/2018 investment to the rate year levels to align with their expected balances at the time rates are changed in this filing. The adjustment will also remove the Schedule 149 revenue associated with these layers as that portion of Schedule 149 will be set to zero in the compliance filing for this case in order to recognize that their recovery will be included in base rates (Adjustment 8.02GP).

2. Remove from the test year the November and December 2018 balances, which will be included in the 2018/2019 investment that will continue to be recovered in the CRM mechanism (Adjustment 8.01GP).

3. The Schedule 149 CRM filing in Docket UG-190464 will go into effect on November 1, 2019. Those rates will be separated between the portion recovering the 2016/2017 and 2017/2018 investment and the portion recovering the 2018/2019 investment. The 2016/2017 and 2017/2018 layers, will be set to zero in May 2020 during the compliance filing in this proceeding.

Q. Please describe the adjustments for CRM.

A. The following two rate case adjustments have been made based on the methodology described above.

Adjustment No. 8.01GP– Remove Schedule 149 CRM from the Test Year

The test year contains two months – November and December 2018 – that are included in PSE's 2018/2019 CRM investment and that will not be transferred to base rates and will continue to be recovered in Schedule 149 after the rates from the case go into effect. Therefore, these amounts are being removed from this filing in order to prevent double recovery of these assets. This pro forma adjustment increases natural gas net operating income by $31,240 and decreases rate base by $9.3 million.

Adjustment No. 8.02 GP – Transfer Schedule 149 CRM

In this adjustment, the 2016/2017 and 2017/2018 CRM investment included in the test year is being pro formed to the rate year levels to align with their expected balances at the time rates are changed in this filing. This pro forma adjustment decreases gas net operating income by $5.3 million and decreases gas rate base by $6.4 million.

V. ATTRITION BASE AMOUNTS

Q. Is PSE proposing an attrition adjustment in this case?

A. Yes. The Prefiled Direct Testimony of Mr. Ronald J. Amen, Exh. RJA-1T, provides the justification and support for a limited proposed attrition adjustment in this case. For many of the cost categories, Mr. Amen determines the attrition factors to use for his adjustment from historical information provided in PSE's annual Commission Basis Reports. He then applies the attrition factors to a base amount in order to grow the cost categories to the expected level in the rate year.

Q. Did you determine the base amounts Mr. Amen uses in his attrition analysis?

A. Yes. The base amounts must be determined in order to have an appropriate starting point for the attrition analysis. Attrition base amounts are a combination of certain test year, restating and pro forma adjustments. Additionally, the attrition base amounts should not include power or purchase gas costs. Therefore, it is necessary to independently develop the attrition base amounts which I have done in Exh. SEF-9.

Q. Please provide an overview of the attrition base amounts presented in Exh. SEF-9.

A. Exh. SEF-9 consists of two pages. The first page contains the information used to develop the electric attrition base amounts, and the second page contains the information used to develop the natural gas attrition base amounts.

In order to not overstate the results of the attrition analysis in the rate year, attrition base amounts should not include most pro forma adjustments; however, they should include most restating and annualizing adjustments. Because of this, the most logical point from which to develop the attrition base amounts is PSE's restated results of operations. The following information explains how the electric and natural gas attrition base amounts were determined.

Electric Attrition Base Amounts:

The following describes each column on page 1 of Exh. SEF-9:

- Column a begins with the restated results of electric operations from Exh. SEF-4E page 4 of 7.
- Columns b-d remove the adjustments to move PSE's rate base and depreciation from AMA to EOP in order to not overstate the attrition results in the rate year.
- Column e removes the adjustment to Colstrip depreciation expense that is included in the restated results of operations in order to not overstate the attrition results in the rate year.
- Column f removes the current period decoupling deferrals from other operating revenues. Because Mr. Piliaris independently calculates the revenues for the attrition analysis, the current period decoupling deferrals, the removal of which are in a proforma adjustment that are not included in the restated results of operations, must be performed.
- Column g removes the variable power costs and revenues that are included in the restated results of operations.
- Column h presents the resulting attrition base amounts for electric used by Mr. Amen.

Natural Gas Attrition Base Amounts:

The following describes each column on page 2 of Exh. SEF-9:

- Column a begins with the restated results of natural gas operations from Exh. SEF-4G page 2 of 4.
- Columns b-c remove the adjustments to move PSE's rate base and depreciation from AMA to EOP in order to not overstate the attrition results in the rate year. Also, the current period decoupling deferrals are removed in column d.
- Column e removes purchase gas costs and revenues that are included in the restated results of operations.

- Column f presents the resulting attrition base amounts for natural gas used by Mr. Amen.

VI. POWER COST ADJUSTMENT MECHANISM

Q. Please summarize Exhibit A-1 in Exh. SEF-11 and explain its importance.

A. Exhibit A-1 is important for two reasons. First, Exhibit A-1 identifies the specific production related costs that are being updated in any given base rates filing, which make up the baseline rate that is used to calculate changes in revenue deficiency in a PCORC. Second, Exhibit A-1 will also be the source of information used in designating both the variable and the fixed components of the total baseline rate, the former of which will be used in tracking the over or under collection of variable power costs in the PCA mechanism and the latter to be used in setting the fixed production costs in the decoupling mechanism.

This variable baseline rate multiplied by the actual delivered load for a period is the amount of variable power costs that are included in customers' rates. The product of this calculation will be compared against only the actual allowable variable power costs during the reporting period plus any adjustments in Exhibit B, such as the Centralia Equity Adder and the EIM fixed costs, to determine the imbalance for sharing against which the bands are applied to determine the deferral balance at the end of each PCA period. PSE requests approval of this schedule in order to provide certainty in its accounting for the PCA mechanism once new rates go into effect.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.