EXHIBIT NO. RCS-1CT
DOCKET NO. UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: RALPH C. SMITH

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-170033** **Docket No. UG-170034** **(*Consolidated*)**

PREFILED
DIRECT TESTIMONY OF
RALPH C. SMITH
ON BEHALF OF
PUBLIC COUNSEL

JUNE 30, 2017

CONFIDENTIAL PER PROTECTIVE ORDER
IN DOCKETS UE-170033 AND UG-170034
(Confidential Information Is Shaded in Grey)

REDACTED VERSION

PREFILED DIRECT TESTIMONY OF RALPH C. SMITH (RCS-1CT)

DOCKETS UE-170033 and UG-170034 (*Consolidated)*

TABLE OF CONTENTS

EXHIBITS LIST

Exhibit RCS-2	Qualifications of Ralph C. Smith.
Exhibit RCS-3	Electric Revenue Requirement
Exhibit RCS-4	Natural Gas Revenue Requirement
Exhibit RCS-5	Data Requests Re: Plant Held for Future Use: PSE Responses to Public Counsel Data Request No. 297 and ICNU Data Request Nos. 63 (revised with Attachment A), 65, and 67
Exhibit RCS-6	Data Requests Re: Temperature Normalization (without Attachments): PSE Responses to WUTC Staff Data Requests Nos. 6 and 46
Exhibit RCS-7	Data Requests Re: Incentive Compensation: PSE Responses to Public Counsel Data Request No. 126 and ICNU Data Request No. 60
Exhibit RCS-8C	Data Requests Re: Pension Expense: PSE Responses to ICNU Data Request Nos. 56 and 57 (with Attachment A), and WUTC Staff Data Request No. 212
Exhibit RCS-9	Data Requests Re: Environmental Remediation: PSE Responses to WUTC Staff Data Request Nos. 278 (with Attachment A) and 284
Exhibit RCS-10C	Data Requests Re: Colstrip: PSE Responses to Public Counsel Data Request Nos. 355, 394, 395, 420, 426 (with Attachment A); Sierra Club Data Request No. 4 (with Attachment A); WUTC Staff Data Request Nos. 142, 296, 359, 359 (revised with Attachments A and B), and 461
Exhibit RCS-11C	Colstrip Strategic Planning Update, dated March 2, 2017
Exhibit RCS-12C	Analysis of Pension Plans

I. INTRODUCTION

Q: Please state your name and business address.

A: Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q: What is your occupation?

A: I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

Q: Please summarize your educational background.

A: I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan.[1] I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan

[1] My testimony in this proceeding is as a Senior Regulatory Consultant, and I am not offering any legal opinions.

Association of Certified Public Accountants. I am also a member of the Michigan Bar Association. I have been a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"), and the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q: Please summarize your professional experience.

A: After graduating from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation, where I have spent the majority of my time for the past 37 years, I performed audit, accounting, and tax work for a wide variety of business clients.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada, as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q: Have you previously testified before the Washington Utilities and Transportation Commission ("WUTC" or "Commission")?

A: Yes. I testified in previous Puget Sound Energy rate cases in Docket Nos. UE-072300 and UG-072301, UE-090704 and UG-090705, and UE-111048 and UG-111049.

Q: Have you prepared an exhibit describing your qualifications and experience?

A: Yes. Exhibit RCS-2 contains a summary of my regulatory experience and qualifications.

Q: On whose behalf are you appearing?

A: I am appearing on behalf of the Public Counsel Unit ("Public Counsel") of the Washington State Attorney General's Office.

Q: Please describe the tasks that you performed related to your testimony in this case.

A: We reviewed the Company's testimony, exhibits, and workpapers, issued information requests, and analyzed Puget Sound Energy's ("PSE", "Puget", or "Company") responses to them. We reviewed and analyzed data (1) to obtain an understanding of PSE's rate filing package as it relates to the Company's proposed rate increase and (2) to formulate an opinion concerning the reasonableness of the Company's proposals on those selected issues.

Q: What is the scope and purpose of your testimony?

A: Larkin was engaged by Public Counsel to conduct a review and analysis and present testimony regarding rate base, operating income, and revenue requirement aspects of the filing.

The purpose of my testimony is to present to the Commission the appropriate test year rate base, overall rate of return, and utility operating income, as well as the appropriate overall revenue requirement and rate increase for the Company in this proceeding.

Q: Are you presenting any exhibits with your testimony?

A: Yes. I am including the following Exhibits with my testimony:

- Exhibit RCS-2 Qualifications of Ralph C. Smith.
- Exhibit RCS-3 presents my electric utility revenue requirement and adjustment schedules.
- Exhibit RCS-4 presents my gas utility revenue requirement and adjustment schedules.

- Exhibit RCS-5 provides data request responses related to Plant Held for Future Use.
- Exhibit RCS-6 provides data request responses related to temperature normalization. Voluminous attachments to these responses are not included.
- Exhibit RCS-7 provides data request responses related to incentive compensation.
- Exhibit RCS-8C provides data request responses related to pension expense. This exhibit contains confidential information.
- Exhibit RCS-9 provides data request responses related to environmental remediation.
- Exhibit RCS-10C provides data request responses related to Colstrip. This exhibit contains confidential information.
- Exhibit RCS-11C presents PSE's confidential Colstrip Strategic Planning Update, dated March 2, 2017, an internal presentation to its Board of Directors.
- Exhibit RCS-12C is a confidential illustration of our analysis of PSE's pension plan.

Q: What test year is being used in PSE's filing?

A: Puget's request for a rate increase is based on a test year ending September 30, 2016, and a rate year of January through December 2018.

Q: What amount of base rate revenue increase has the Company requested for electric utility service?

A: In its original filing for electric utility service dated January 13, 2017, PSE requested an increase in its base rates for electric utility service of $149.062 million. After allocation to wholesale and special contract customers, the Company's requested increase is $148.656 million over the test year adjusted base revenues of $2.064 billion for an increase of approximately 7.20 percent.[2]

Q: What amount of base rate revenue increase had the Company requested for gas utility service?

A: In its original filing for gas utility service dated January 13, 2017, PSE requested an increase in its base rates for gas utility service of $22.993 million over the test year adjusted base revenues of $815.784 million for an increase of approximately 2.82 percent.[3]

Q: You referenced PSE's original electric and gas filings. Did the Company file a supplemental filing?

A: Yes. PSE filed a supplemental filing on April 3, 2017, in which it updated its requested base rate revenue increase for both electric and gas operations.

Q: What amount of base rate revenue increase did the Company request in its supplemental filing for electric utility service?

[2] Direct Testimony of Katherine J. Barnard, Exh. KJB-1T at 12:5-7.
[3] Direct Testimony of Susan E. Free, Exh. SEF-1T at 4:14-16.

A: In its supplemental filing, PSE reduced its initial request for electric utility service of $149.062 million to $144.053 million. After allocation to wholesale and special contract customers, the Company's revised requested increase for electric utility service is $143.648 million over the test year adjusted base revenues of $2.067 billion for an increase of approximately 6.95 percent.[4]

Q: What amount of base rate revenue increase did the Company request in its supplemental filing for gas utility service?

A: In its supplemental filing, PSE reduced its initial request for gas utility service of $22.993 million to $22.813 million over the test year adjusted base revenues of $815.734 million, for an increase of approximately 2.80 percent.[5]

Q: What cost of capital and return on equity is the Company requesting?

A: In both its original and supplemental filings, PSE is requesting a test year cost of capital of 7.74 percent and a proposed return on equity of 9.80 percent. The cost of capital that the Company has requested has been reproduced on Exhibit RCS-3, Schedule D for the electric utility and on Exhibit RCS-4, Schedule D for the gas utility.

Q: Which of the Company's filings did you use as your starting point in determining the appropriate overall revenue requirement and rate increase for the Company in this proceeding?

[4] Prefiled Supplemental Direct Testimony of Katherine J. Barnard, Exh. KJB-10T at 1:19-2:4.
[5] Prefiled Supplemental Direct Testimony of Susan E. Free, Exh. SEF-8T at 1:16-22.

A: I used the Company's original filing dated January 13, 2017, as the starting point in determining the appropriate overall revenue requirement and rate increase for the Company.

Q: How have you incorporated the changes made in the Company's April 3, 2017 supplemental testimony?

A: I incorporated the Company's supplemental base revenue rate increase request through a series of adjustments, as discussed later in my testimony.

II. SUMMARY OF FINDINGS AND CONCLUSIONS

A. Electric Utility Operations

Q: Please summarize your findings and conclusions for electric utility service in this proceeding.

A: I have reached the following conclusions in this proceeding concerning PSE's electric utility revenue requirement:[6]

1. The appropriate rate base for electric operations in this proceeding amounts to $5.106 billion, which is approximately $8.168 million higher than the Company's proposed rate base of $5.098 billion, as shown on Exhibit RCS-3, Schedule A, line 1 and on Schedule B.

[6] The Company requested amounts in this section are from the PSE's original filing dated January 13, 2017. As noted above, I used the Company's original filing as the starting point in the determination of my recommended revenue requirement.

2. The Public Counsel's expert cost of capital witness, Dr. Woolridge, has recommended a return on equity of 8.85 percent, and overall rate of return of 7.28 percent for PSE's electric operations. In contrast, PSE has requested an overall rate of return of 7.74 percent, including a return on equity of 9.80 percent, as shown on Exhibit RCS-3, Schedule A, line 2 and on Schedule D.
3. The appropriate test year utility operating income for PSE's electric operations amounts to approximately $327.94 million, which is approximately $25.64 million higher than the Company's proposed test year utility operating income of $302.31 million, as shown on Exhibit RCS-3, Schedule A, line 4 and on Schedule C.
4. To calculate the base rate revenue increase, I used a gross revenue conversion factor ("GRCF") of 0.619051, as shown Exhibit RCS-3, Schedule A-1. This factor is the same as the 0.619051 used by PSE.
5. The application of the recommended overall rate of return of 7.28 percent to the recommended rate base of $5.106 billion produces a required return of approximately $371.73 million, as shown on Exhibit RCS-3, Schedule A, column B, line 3. Compared to the adjusted net operating income of approximately $327.94 million, this represents a deficiency of approximately $43.79 million, as shown on Exhibit RCS-3, Schedule A, column B, line 5. Applying the GRCF of 0.619051 indicates that the Company has an annual base rate revenue requirement deficiency of

approximately $70.73 million, as shown on Exhibit RCS-3, Schedule A, column B, line 7. As shown on Exhibit RCS-3, Schedule A, column C, line 7, this represents a difference of approximately $78.33 million versus the Company's proposed base rate revenue deficiency of $149.062 million (before the allocation to wholesale and special contact customers).

6. The total base rate revenue increase of approximately $70.33 million (after the allocation to wholesale and special contract customers) is an overall increase of 3.40 percent over adjusted revenue at current rates of approximately $2.067 billion, as shown on Exhibit RCS-3, Schedule A, lines 10 and 11.

B. Gas Utility Operations

Q: Please summarize your findings and conclusions for gas utility service in this proceeding.

A: I have reached the following findings and conclusions in this proceeding concerning PSE's gas utility revenue requirement:

1. The appropriate rate base for gas operations in this proceeding amounts to $1.766 billion, which is approximately $5.47 million higher than the Company's proposed rate base of $1.761 billion, as shown on Exhibit RCS-4, Schedule A, line 1 and on Schedule B.
2. Public Counsel's expert cost of capital witness, Dr. Woolridge, has recommended a return on equity of 8.85 percent, and overall rate of return

of 7.28 percent for PSE's gas operations. In contrast, PSE has requested an overall rate of return of 7.74 percent, including a return on equity of 9.80 percent, as shown on Exhibit RCS-4, Schedule A, line 2 and on Schedule D.

3. The appropriate test year utility operating income for PSE's gas operations amounts to approximately $136.97 million, which is approximately $14.96 million higher than the Company's proposed test year utility operating income of $122.012 million, as shown on Exhibit RCS-4, Schedule A, line 4 and on Schedule C.

4. To calculate the base rate revenue increase, I used a GRCF of 0.620450, as shown Exhibit RCS-4, Schedule A-1. This factor is the same as the 0.620450 used by PSE.

5. The application of the recommended overall rate of return of 7.28 percent to the recommended rate base of $1.766 billion produces a required return of approximately $128.58 million, as shown on Exhibit RCS-4, Schedule A, column B, line 3. Compared to the adjusted net operating income of approximately $136.97 million, this represents a sufficiency of approximately $8.40 million, as shown on Exhibit RCS-4, Schedule A, column B, line 5. Applying the GRCF of 0.620450 indicates that the Company has an annual base rate revenue requirement sufficiency of approximately $13.53 million, as shown on Exhibit RCS-4, Schedule A, column B, line 7. As shown on Exhibit RCS-4, Schedule A, column C,

line 7, this sufficiency represents a difference of approximately $36.53 million versus the Company's proposed base rate revenue deficiency of $22.993 million.

6. The total base rate revenue decrease of approximately $13.533 million is an overall decrease of 1.66 percent over adjusted revenue at current rates of approximately $815.734 million, as shown on Exhibit RCS-4, Schedule A, lines 8 and 9.

III. RATE BASE

Q: What adjustments are you recommending to PSE's electric and gas rate base?

A: I am recommending the adjustments to PSE's requested electric and gas utility rate base discussed below.

A. B-1, White River Hydroelectric Project (Electric)

Q: Where does PSE discuss the background of the White River Hydroelectric Project?

A: This is discussed on pages 55-59 of the Prefiled Direct Testimony of Company witness Ms. Barnard.

Q: Please explain PSE's originally proposed adjustment to rate base as it relates to White River.

A: As discussed on page 59 of PSE witness Ms. Barnard's Prefiled Direct Testimony, the Company proposes to transfer the value of the land out of the regulatory asset and into plant in service (FERC account 101) and plant held for future use (FERC account 105). In addition, the Company's adjustment pro forms the regulatory assets, including the value of the unrecovered plant net of accumulated amortization and the net proceeds related to the White River land sold at the beginning of the rate year at the existing level of amortization.

As originally proposed, this adjustment reduced PSE's rate base for electric operations by $3,888,479.[7] As discussed in further detail in the Operating Income section of my testimony, PSE is proposing to amortize the White River regulatory assets over a three-year period beginning January 1, 2018.

Q: Did the Company update its proposed rate base adjustment related to White River?

A: Yes. As discussed on page 10 of her Prefiled Supplemental Direct Testimony, PSE witness Ms. Barnard stated that this adjustment was updated to reflect (1) net proceeds received that related to a timber contract on the White River property, and (2) an update to incorporate the February 28, 2017, balance of the regulatory asset accounts to reflect charges related to prior sales of White River surplus properties.

[7] This adjustment does not impact PSE's gas operations.

Q: How did you reflect the Company's updates to the White River related adjustments in the determination of your recommended rate base?

A: As shown on Exhibit RCS-3, Schedule B-1, incorporating the Company's updated adjustment reduces PSE's rate base for electric operations by an additional net amount of $220,245. As noted above, this adjustment does not impact the Company's gas operations.

Q: Did the Company's update to its proposed White River adjustment also impact the amount of the regulatory assets that PSE proposes to amortize over a three-year period?

A: Yes. This aspect of the Company's updated White River adjustment is discussed in the Operating Income section of my testimony under Adjustment No. C-10.

B. B-2, Production Adjustment (Electric)

Q: Please explain PSE's originally proposed production adjustment.

A: As discussed on pages 60-62 of Ms. Barnard's Prefiled Direct Testimony, this proposed adjustment decreased production related rate base, as well as certain production expenses by the load and customer production factors that PSE used to calculate power costs. Specifically, the Company applied this proposed adjustment to production related items in order to reduce the expense levels as PSE anticipates that the recovery of these expenses will be offset by expected load and/or customer growth between the test year and the rate year. As originally proposed, the Company's production adjustment reduced rate base for electric operations by $54,768,452. This proposed adjustment does not impact gas operations. As discussed in further detail in the Operating Income section of my testimony under Adjustment C-11, PSE's proposed production adjustment also reduced net operating income for electric operations by $3,130,918.

Q: Did the Company update its proposed production adjustment in its supplemental filing?

A: Yes. As discussed on page 11 of her Prefiled Supplemental Direct Testimony, PSE witness Ms. Barnard revised this adjustment to reflect the update to the White River regulatory assets discussed above. After applying a fixed production factor of 2.535 percent, the Company's updated production adjustment increases rate base for electric operations by $5,583.

Q: How did you reflect the Company's update to its proposed production adjustment in the determination of your recommended rate base?

A: As shown on Exhibit RCS-3, Schedule B-2, incorporating the Company's updated adjustment increases PSE's rate base for electric operations by the $5,583 noted above. As previously discussed, this adjustment does not impact the Company's gas operations.

C. B-3, Accumulated Depreciation (Electric and Gas)

Q: Please explain the adjustment to accumulated depreciation.

A: This adjustment reflects the impacts of the new depreciation rates that are being recommended by Public Counsel witness Roxie McCullar and the resulting impact on depreciation expense. Specifically, as shown on Exhibit RCS-3, Schedule B-3, as the result of the new depreciation rates being recommended by Ms. McCullar, this adjustment reduces accumulated depreciation (thus increases rate base) for electric operations by $13,568,804, or 50 percent of the adjustment to depreciation expense that is shown on Exhibit RCS-3, Schedule C-12.

Q: Was there a similar adjustment for PSE's gas utility operations?

A: Yes. Similarly, as shown on Exhibit RCS-4, Schedule B-3, this adjustment reduces accumulated depreciation (thus increases rate base) for gas operations by $8,415,549, or 50 percent of the adjustment to depreciation expense that is shown on Exhibit RCS-4, Schedule C-12.

D. B-4, Accumulated Deferred Income Taxes (Electric and Gas)

Q: Please explain your adjustment to Accumulated Deferred Income Taxes ("ADIT").

A: This adjustment reflects the impacts of the new book depreciation rates for PSE recommended by Public Counsel witness Roxie McCullar. As shown on Exhibit RCS-3, Schedule B-4, this adjustment increases ADIT (thus reduces rate base) for electric operations by $4,749,081. The impact on ADIT reflects the difference between book and tax depreciation. As a result of the recommendations of Ms. McCullar, the adjusted book depreciation expense will be lower than the amount proposed by PSE. Ms. McCullar's recommendation only addresses depreciation rates that would be used for book depreciation. Tax depreciation is not changed. Consequently, the results of Ms. McCullar's recommended depreciation rates results in lower book depreciation expense and a larger difference between book and tax depreciation.

Q: Is there a similar adjustment for PSE's gas utility operations?

A: Yes. As shown on Exhibit RCS-4, Schedule B-4, this similar adjustment increases ADIT (thus reduces rate base) for gas operations by $2,945,442.

E. B-5, Plant Held For Future Use (Electric)

Q: Does the Company's proposed rate base for electric and gas operations include amounts for Plant Held for Future Use ("PHFFU").

A: Yes. PSE reflected a test year balance of PHFFU totaling approximately $49 million.[8]

In addition, as it relates to gas operations, PSE reflected a test year balance of PHFFU totaling approximately $1.4 million.[9]

Q: What is the basis for the Company's request for inclusion of this land in rate base in this proceeding?

A: PSE cited the Commission's Eleventh Supplemental Order, dated September 21, 1993, in Docket Nos. UE-920433, UE-920499, and UE-92162. (Hereinafter "Eleventh Supplemental Order".) In those dockets, the Commission Staff had recommended the removal of properties that (1) Puget Sound Power &

[8] Exh. RCS-5, PSE response to ICNU Data Request No. 63.
[9] Exh. RCS-5, PSE Response to Public Counsel Data Request No. 297.

Light Company did not have specific plans for as required by the system of accounts, and (2) had been in PHFFU for longer than 20 years.[10]

Q: Did the Commission adopt Staff's recommendations regarding PHFFU in that Order?

A: Yes. Specifically, on page 90 of its Eleventh Supplemental Order in those dockets, the Commission stated in part that:

> The Commission is also concerned with the number of properties which have been held in this account for many, many years without action. Although litigation may cause some delays in a proposed use of property, some of the properties are apparently just "sitting".
>
> The Commission therefore adopts the Commission Staff's proposal for treatment of this account, including Mr. Martin's **twenty-year benchmark for exclusion of properties. If property has not been acted on within twenty years, the ratepayers should not continue to bear these costs**. The Commission specifically rejects the company's claim that establishment of a benchmark would be retroactive ratemaking. If that were the case, the Commission would never be able to establish reasonable guidelines. (Emphasis supplied.)

Q: Do any of the properties included in PSE's test year PHFFU account meet the Commission's directive that properties that have not been acted on within 20 years should be excluded from rate base as discussed in the Eleventh Supplemental Order?

A: Yes. The property listed in the table below was first placed into the PHFFU account on December 31, 1992. PSE shows a projected use date of

[10] Exh. RCS-5, PSE Response to ICNU Data Request No. 065.

October 1, 2019. This is more than 20 years. This information was provided with PSE's first revised response to ICNU No. 063, which is included in Exhibit RCS-5. PSE has included this PHFFU in its test year rate base for electric operations:

PP Asset Number	WO #	Vintage Year	FERC #	Description	9/30/2016 Balance	Date in Future Use	Projected In Service Date	Super Number
39060	CONV	1992	E3500	BPA KITSAP Naval Trans Plant Land RTS	$ 147,139	12/31/1992	10/1/2019	TLN-0052
39061	CONV	1993	E3500	BPA KITSAP Naval Trans Plant Land RTS	$ 289,426	12/31/1992	10/1/2019	TLN-0052
				Total	$ 436,566			
Source: First revised response to ICNU No. 063, Attachment A								

As shown in the table under the "Vintage Year" column, the years 1992 and 1993 are reflected for this property under each respective PP Asset Number. In addition, under the "Date in Future Use" column, the date indicated for this property is December 31, 1992. According to the response to ICNU Data Request No. 067, the "Vintage Year" column reflects the year in which the property was originally acquired and the "Date in Future Use" column reflects the date when the property was originally recorded in PHFFU. PSE's response to ICNU Data Request No. 067 is included in Exhibit RCS-5.

Q: Has PSE indicated when the property identified above is scheduled to be in service?

A: Yes. As reflected in Exhibit RCS-5, PSE indicates in the "Notes" section of Attachment A from ICNU No. 063 that the Kitsap Naval Land is scheduled to be in service on October 1, 2019. Based upon the date when PSE first recorded the Kitsap Naval Land property in PHFFU (i.e., December 31, 1992, per the "Date in

Future Use" column from Attachment A in ICNU No. 063), this property has been in PHFFU for nearly 25 years as of the end of the test year, and it would be in PHFFU for nearly 27 years if this asset is placed into service on October 1, 2019.

Q: What is your recommendation?

A: Based upon applying the criteria stated in the Commission's Eleventh Supplemental Order, which states in part that the cost of property that has been held in PHFFU for longer than 20 years should not be borne by ratepayers, I am recommending that the two components of the Kitsap Naval Land (as identified by PP Asset Numbers 39060 and 39061) be removed from PHFFU for electric operations. As shown on Exhibit RCS-3, Schedule B-5, this adjustment decreases electric rate base by $466,566. This adjustment does not apply to gas operations.

IV. OPERATING INCOME

Q: What amounts of operating income did PSE propose in its original filing?

A: In its original filing, PSE proposed net operating income of $302.31 million for electric utility operations and $122.01 million for gas utility operations.

Q: Did PSE make revisions to some of its net operating income adjustments in its April 3, 2017 supplemental filing?

A: Yes. In its supplemental filing, PSE proposed net operating income of $305.39 million for electricity utility operations and $122.12 million for gas utility operations.

Q: How have you reflected those PSE updates to net operating income?

A: I incorporated the Company's supplemental net operating income request through a series of adjustments, as discussed in the following section of my testimony.

Q: Are you recommending adjustments to net operating income that were not made by PSE in its original or supplemental filing?

A: Yes. I am recommending the adjustments to PSE's net operating income discussed below.

A. C-1, Temperature Normalization (Gas)

Q: Please explain PSE's proposed temperature normalization adjustment.

A: As discussed in the Prefiled Direct Testimonies of Company witnesses Ms. Barnard (electric operations) and Ms. Free (gas operations), PSE's revenues have been reflected on a volumetric basis at 2011 general rate case base rate levels during the test year. Therefore, PSE proposed a temperature normalization adjustment for both electric and gas operations to restate test year delivered load and revenue to the level it expects to occur under "normal" weather conditions, as the test year was warmer than usual.

For electric operations, PSE based its adjustment on the difference between actual test year generated, purchased, and interchange ("GPI") load for electric, as well as temperature normalized GPI MWh adjusted for system losses. For gas operations, PSE based its adjustment on the difference between actual and normalized therms.

Q: What is the impact of the Company's temperature normalization adjustments on its requested revenue requirement for electric and gas operations?

A: For electric operations, the Company's adjustment increased operating revenues by $28,313,253 and operating expenses by $10,785,909 for a net increase to operating income of $17,527,344.

For gas operations, the Company's adjustment increased operating revenues by $58,088,570, purchased gas costs by $30,724,734 and operating expenses by $11,293,877 for a net increase to operating income of $16,069,959.

Q: Did the Company update its proposed temperature normalization adjustment in its April 3, 2017, supplemental filing?

A: Yes. In its April 3, 2017, supplemental filing, PSE updated its temperature normalization adjustment for its gas utility operations. As discussed on page five of his Prefiled Supplemental Direct Testimony, PSE witness Jon A. Pilaris stated that subsequent to the Company's January 13, 2017, filing, an error was discovered in the weather normalization calculations for PSE's gas operations whereby an incorrect historic period was used to estimate the natural gas weather normalization coefficients.[11]

[11] Exh. RCS-6, PSE Responses to WUTC Staff Data Request Nos. 006 and 046.

Q: How did you reflect the Company's corrected temperature normalization adjustment in the determination of your recommended net operating income for gas operations?

A: As shown on Exhibit RCS-4, Schedule C-1, incorporating the Company's updated temperature normalization adjustment reduces gas operating revenue by $50,044, reduces purchased gas by $11,594, and reduces gas utility operating expenses by $2,275. As previously discussed, this adjustment does not impact the Company's electric operations.

B. C-2, Bad Debt Expense (Electric and Gas)

Q: Please explain PSE's proposed adjustment to bad debt expense.

A: As discussed on page 33 of her Prefiled Direct Testimony, PSE witness Ms. Barnard stated that, consistent with prior cases, the Company calculated its proposed bad debt rate by using the average bad debt percentage for three of the last five years after removing the high and low years (i.e., a three-year average). In addition, Ms. Barnard stated that it takes four months to write off a customer's bill. As a result, the ratio of the write-off versus revenue is offset by four months. Using this methodology, PSE calculated its proposed bad debt rate by dividing actual test year write-offs by net revenues as of May 31 for the three (out of the five years) that were used. PSE then multiplied test year net revenues by the average bad debt percentage to derive its proposed level of bad debt expense. PSE made an adjustment to reduce O&M expense by $845,154 for electric operations and increase O&M expense by $244,361 for gas operations in its January 13, 2017, filings.

Q: Did the Company update its proposed bad debt expense adjustment in its supplemental filing?

A: Yes. As discussed on page seven of her Prefiled Supplemental Direct Testimony, PSE witness Ms. Barnard stated that the Company's bad debt expense adjustments, as originally filed, contained an error in that the proposed bad debt rate was applied to revenues that were also included in the temperature normalization adjustment, which reflected a double-count of expenses. The Company's revised bad debt expense adjustment removed the revenues that were associated with the temperature normalization adjustment.

Q: How did you reflect the Company's revised bad debt expense adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-2, for electric operations, incorporating the Company's updated bad debt expense adjustment reduces O&M expenses by an additional $202,638.

As shown on Exhibit RCS-4, Schedule C-2, for gas operations, incorporating the Company's updated bad debt expense adjustment reduces O&M expense by $298,575.

C. C-3, Incentive Compensation Expense (Electric and Gas)

Q: Please explain PSE's proposed adjustment to incentive compensation expense.

A: As discussed on pages 15-16 of the Prefiled Direct Testimony of PSE witness Ms. Free, the Company's proposed adjustment to incentive compensation expense uses a four-year average of incentive compensation paid to employees and is based on payouts which occurred in March for years 2013 through 2016, which relate to calendar years 2012 through 2015. As originally proposed, PSE's adjustment to incentive compensation expense reduced operating expenses by $157,551 for electric operations and by $213,058 for gas operations.

Q: Did the Company update its proposed incentive compensation expense adjustment in its supplemental filing?

A: Yes, the Company updated its proposed incentive compensation expense adjustment in its supplemental filing. As discussed on page five of her Prefiled Supplemental Direct Testimony, PSE witness Ms. Free stated that the Company's proposed adjustment to incentive compensation expense has been updated to include the March 2017 payout and now reflects a four-year average of incentive compensation paid to employees that is based on payouts which occurred in March for years 2014 through 2017, which relate to calendar years 2013 through 2016.

Q: How did you reflect the Company's revised incentive compensation expense adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-3, incorporating the Company's updated incentive compensation expense adjustment increases operating expenses by $411,468 for electric operations. In addition, as shown on Exhibit RCS-4, Schedule C-3, incorporating the Company's updated incentive compensation expense adjustment increases operating expenses by $167,747 for gas operations.

Q: Did the Company include amounts related to stock-based compensation in its requested revenue requirement?

A: No. PSE's response to Public Counsel Data Request No. 126 stated that the Company does not have any stock based programs. The response to ICNU Data Request No. 060 also indicated that PSE is not including SERP in establishing its revenue requirement. Exhibit RCS-7 contains copies of PSE’s response to Public Counsel Data Request No. 126 and PSE’s response to ICNU Data Request No. 060.

D. C-4, Interest on Customer Deposits (Electric and Gas)

Q: Please explain PSE's proposed adjustment to interest on customer deposits.

A: As discussed in the Prefiled Direct Testimony of PSE witness Ms. Free, this adjustment reflects the impact of the interest associated with using customer deposits as a reduction to rate base. Specifically, this adjustment reflects the cost of interest on customer deposits. It was initially based on the most current annual interest rate at the time of the Company's January 13, 2017, filing, which was 0.49 percent for 2016. As indicated in Ms. Free's testimony, this interest rate is determined annually and is based on the interest rate for a one year Treasury Constant Maturity as of the 15th day of January.

Q: Did the Company update its proposed interest on customer deposits in its supplemental filing?

A: Yes, the Company updated its proposed interest on customer deposits in its supplemental filing. As discussed on page six of her Prefiled Supplemental Direct Testimony, Ms. Free stated that the interest on customer deposits adjustment was updated to reflect the interest rate of 0.80 percent, which became effective on January 15, 2017.

Q: How did you reflect the Company's revised interest on customer deposits adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-4, for electric operations, incorporating the updated interest rate on customer deposits increases expense by $68,435.

As shown on Exhibit RCS-4, Schedule C-4, for gas operations, incorporating the updated interest rate on customer deposits increases expense by $19,428.

E. C-5, Payroll Expense (Electric and Gas)

Q: Please explain PSE's proposed adjustment to payroll expense.

A: As discussed on pages 19-22 of the Prefiled Direct Testimony of Company witness Ms. Free, PSE's proposed wage increases for the Company's union and non-union employees. The union employees including those that are represented by the International Brotherhood of Electrical Workers ("IBEW") and those represented by the United Association of Plumbers and Pipefitters ("UA"). The wage increases proposed by PSE for these union employees are based upon annual wage increases that are included in the approved contracts for the IBEW and UA union employees. Specifically, for the IBEW union employees, the Company has proposed a compounded wage increase of 0.69 percent, which reflects the portion of a contracted wage increase of 2.75 percent that was effective January 1, 2016, that falls outside of the test year ended September 30, 2016, (i.e., October through December 2016). For the UA employees, the Company has reflected a contracted wage increase of 3.00 percent which became effective October 1, 2016.

For the Company's non-union employees, PSE initially used an average wage increase that includes a wage increase of 2.91 percent that was effective March 1, 2016, as well as an estimated 3.00 percent increase effective March 1, 2017, for compounded wage increase over test year levels of 4.25 percent.

In addition, PSE weighted this increase by prior year actual salary increases to account for what the Company refers to as "slippage" whereby newly hired non-union employees' salaries are less than the salaries of the non-union employees being replaced. To calculate the slippage adjustment, the Company used the annualized payroll for non-union employees as of March 1 over the last five years from which the average annual salary per non-union employee was determined.

As originally proposed, PSE's adjustment to payroll expense increased operating expenses by $1,497,038 for electric operations and by $972,167 for gas operations.

Q: Did the Company update its proposed payroll expense adjustment in its supplemental filing?

A: Yes, the Company updated its proposed payroll expense adjustment in its supplemental filing. As discussed on page six of her Prefiled Supplemental Direct Testimony, PSE witness Ms. Free stated that the Company updated its proposed adjustment to reflect the actual wage increase effective March 1, 2017, for non-union employees to 2.85 percent from the original estimate of 3.00 percent. Using the actual wage increase of 2.85 percent reduced the compounded wage increase over test year levels from 4.25 percent to 4.10 percent.

In addition, using the actual 2.85 percent wage increase resulted in an updated “slippage” calculation that changed from 78.78 percent as originally proposed to 72.73 percent.

Applying the updated overall slippage percentage of 72.73 percent to the compounded wage increase of 4.10 percent resulted in an effective wage increase of 2.98 percent for non-union employees versus the 3.35 percent as originally proposed by PSE.

Q: How did you reflect the Company's updated payroll expense adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-5, incorporating the Company's updated payroll expense adjustment decreases operating expenses (including payroll taxes) by $214,343 for electric operations. In addition, as shown on Exhibit RCS-4, Schedule C-5, incorporating the Company's updated payroll expense adjustment decreases operating expenses (including payroll taxes) by $99,628 for gas operations.

F. C-6, Investment Plan Expense (Electric and Gas)

Q: Please explain PSE's proposed adjustment to investment plan expense.

A: As discussed on pages 22-23 of the Prefiled Direct Testimony of Company witness Ms. Free, the Company's proposed adjustment to investment plan expense is tied to PSE's proposed payroll expense adjustment and is based on current employee contribution rates.

Q: Did the Company update its proposed investment plan expense adjustment in its supplemental filing?

A: Yes, the Company updated its proposed investment plan expense adjustment in its supplemental filing. As discussed on page eight of her Prefiled Supplemental Direct Testimony, Ms. Free stated that this adjustment was updated to reflect the revised payroll expense adjustment previously discussed above.

Q: How did you reflect the Company's updated investment plan expense adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-6, for electric operations, this adjustment reduces O&M expense by $15,134. As shown on Exhibit RCS-4, Schedule C-6, for gas operations, this adjustment reduces O&M expense by $7,307.

G. C-7, Power Costs (Electric)

Q: Please explain PSE's proposed adjustment to power costs.

A: As discussed on pages 40-42 of the Prefiled Direct Testimony of Company witness Ms. Barnard, the Company's proposed adjustment is to adjust the test year power costs to reflect the production related revenues and expenses, as well as production O&M expenses, which relate to power costs that are projected to be incurred in the rate year. This adjustment as proposed in PSE's original filing reduced net operating income for electric operations by $19,501,105. This adjustment does not apply to gas operations.

Q: Did the Company update its proposed power cost adjustment in its supplemental filing?

A: Yes, the Company updated its proposed power cost adjustment in its supplemental filing. As discussed on page 11 of her Prefiled Supplemental Direct Testimony, Ms. Barnard stated that the Company's proposed power cost adjustment was updated to reflect the revised power costs that relate to the Company's revised production costs and updated PCA Baseline Power Rate.

Q: How did you reflect the Company's updated power cost adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-7, for electric operations, incorporating the Company's updated power cost adjustment increases operating revenue by $2,985,417 and reduces power costs by$4,289,345. As noted above, this adjustment does not apply to gas operations.

H. C-8, Montana Electric Energy Tax (Electric)

Q: Please explain this PSE proposed adjustment.

A: As discussed on page 43 of the Prefiled Direct Testimony of Company witness Ms. Barnard, the purpose of this adjustment, which applies to electric operations, is to adjust the test year level of Wholesale Energy Transaction Tax ("WETT") and Electricity and Electrical Energy License Tax ("EELT") to the amounts projected to be incurred during the rate year that are associated with the power generated at Colstrip based upon the current tax structure. This adjustment as originally proposed by PSE, reduced taxes other than income by $69,720.

Q: Did the Company update its proposed Montana Electric Tax adjustment in its supplemental filing?

A: Yes, the Company updated its proposed Montana Electric Tax adjustment in its supplemental filing. As discussed on page nine of her Prefiled Supplemental Direct Testimony, Ms. Barnard stated that the Montana Electric Tax adjustment was updated to reflect the revised power costs that relate to rate year generation at Colstrip and to which the WETT and EELT are applied.

Q: How did you reflect the Company's revised Montana Electric Tax adjustment in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-8, for electric operations, incorporating the updated Montana Electric Tax adjustment decreases taxes other than income by $24,331 for electric operations. As noted above, this adjustment does not apply to gas operations.

I. C-9, Storm Damage Expense (Electric)

Q: Please explain PSE's adjustment to storm damage expense.

A: There are two components to the Company's proposed storm damage expense adjustment as discussed on pages 44-46 of the Prefiled Direct Testimony of PSE witness Ms. Barnard. First, the Company proposes to normalize the test year level of normal storm expense based on a six-year average. The second component of PSE's proposed storm damage expense adjustment relates to amortizing the costs associated with catastrophic storms, which the Company has deferred. This portion of PSE's proposed adjustment is broken down into three separate components.

Q: Please discuss the three separate components of PSE's proposed storm damage expense adjustment that relates to catastrophic storms.

A: For the first component of the proposed adjustment that relates to catastrophic storm damage expense, PSE initially proposed to amortize over four years, new deferred catastrophic storm costs, covering the period 2010 through 2016, that have not yet been approved for recovery and totals $50.7 million. This amount is offset by a credit amount of $12.6 million, which reflects catastrophic storm deferral balances that were approved for recovery in the Company's 2011 rate case and were fully amortized prior to the end of the test year in the current proceeding.

The second component of catastrophic storm deferrals relates to the December 13, 2006, "Hanukkah Eve" wind storm in which a 10-year amortization period was approved by the Commission in the Company's 2007 rate case.[12] Ms. Barnard stated that the remaining portion of these deferred 2006 wind storm

[12] See Order 12 dated October 8, 2008, from Docket Nos. UE-072300 and UG-072301 in which the Commission adopted a settlement between PSE and the intervenors in that proceeding.

costs, which total $6.6 million, are set to be fully amortized over 10 months into the rate year in the current proceeding.

The third component of catastrophic storm deferrals relates to the January 2012 snow, ice, and wind event referred to as "Snowmageddon"[13] in which a large storm damage balance totaling $60.3 million was deferred. The Company is proposing that the deferred costs related to the January 2012 snow event be amortized over a six-year period.

The Company's overall storm damage amortization adjustment as originally proposed increases operating expenses by $6.7 million for electric operations. This adjustment does not apply to gas operations.

Q: Did the Company update its proposed storm damage expense adjustment in its supplemental filing?

A: Yes, the Company updated its proposed storm damage expense adjustment in its supplemental filing. As discussed on pages 9-10 of her Prefiled Supplemental Direct Testimony, Ms. Barnard stated that the Company's proposed storm damage expense adjustment was updated to (1) reflect the deferral balance through February 28, 2017, as relates to the storm event which occurred on October 14, 2016, and (2) to include an additional deferral related to a snow storm that occurred on February 4, 2017, and for which notice was provided by PSE to

[13] The "Snowmageddon" events were comprised of a snow and ice event that occurred on January 18, 2012, and a wind event that occurred on January 24, 2012.

the Commission. The result of the Company's update to storm damage expense is an increase to operating expenses totaling $2.579 million.

Q: Are you recommending any adjustments to the Company's proposed storm damage amortization expense?

A: Yes, I am recommending one adjustment. Specifically, I recommend that the $60.3 million cost related to the January 2012 catastrophic Snowmageddon events be amortized over 10 years, rather than PSE's proposed six years. Reasons for this recommendation include the following:

1. Using a longer amortization period for this extremely costly storm will help ameliorate the rate impacts.
2. Using a longer amortization period is better correlated with the infrequent experience of storms as devastating and costly as the extraordinary January 2012 Snowmageddon event.

Q: Does PSE agree that using a longer amortization period for these extremely costly storm events will help ameliorate the rate impacts on customers?

A: Apparently, PSE agrees with this concept. As stated on page 46 of her Prefiled Direct Testimony, Ms. Barnard stated: "Due to the relative size of the balance, PSE proposes that this amount be amortized over six years instead of four years in order to mitigate rate impact on customers." The rate impact on customers of this extraordinarily costly storm would be better mitigated by a longer amortization period.

Q: What amortization period do you recommend for the costs related to the 2012Snowmageddon events?

A: I recommend a 10-year amortization period. As shown in the table below, the $60.3 million cost of the 2012 Snowmageddon storm events is significantly higher than the costs of other catastrophic storms that occurred between 2014 and 2017, all of which are being amortized over a four-year period.

Description	2014	2015	2016	2017
2012 Snowmageddon Storm Costs	$ 60,295,490	$ 60,295,490	$ 60,295,490	$ 60,295,490
Other Catastrophic Storm Costs	$ 18,185,673	$ 24,157,767	$ 10,432,667	$ 8,153,023
Difference	$ 42,109,817	$ 36,137,723	$ 49,862,823	$ 52,142,467
Percentage Difference	231.55%	149.59%	477.95%	639.55%
Source: Adjustment No. 14.05 from PSE's supplemental filing				

The use of a 10-year recovery period, in essence, treats PSE's cost related to the Snowmageddon storm events as a "once-per-decade" event for ratemaking purposes. A period longer than 10 years could be justified based on the historic infrequency of storms of such extraordinary devastation.

Q: Please explain how your recommendation of a 10-year amortization period better mitigates the impact on ratepayers than PSE's proposed period of six years for the extraordinary cost of the Snowmageddon storm event.

A: The annual allowance for catastrophic storm costs of $24.8 million under my recommendation better mitigates the impact on ratepayers than the Company's proposed $28.8 million. Using a 10-year amortization period produces an annual amortization amount for the $60.295 million Snowmageddon storm events of approximately $6.03 million (versus approximately $10 million using the six-year amortization period requested by PSE). In addition to the $18.7 million being requested by PSE for amortization of other catastrophic storms, this produces an annual allowance for catastrophic storm costs of $24.8 million. This allowance is approximately 60 percent higher than the test year recorded catastrophic storm amortization expense of $15.5 million.

Q: What adjustment to PSE's proposed operating expenses results from your recommendation concerning storm damage costs?

A: My recommendation concerning storm damage costs decreases PSE's requested catastrophic storm amortization expense by $4.020 million for electric operations. As noted above, this adjustment does not apply to gas operations.

Q: After reflecting the Company's update along with your recommended adjustment related to the Snowmageddon snow event amortization period, what is your overall adjustment to storm damage expense?

A: As shown on Exhibit RCS-3, Schedule C-9, after reflecting the Company's update and my recommended adjustment related to the Snowmageddon snow event amortization, my net adjustment to storm damage expense is a decrease to O&M expense of $1.441 million.

J. C-10, White River Amortization Expense

Q: Please explain your adjustment to White River amortization expense.

A: This adjustment relates to the Company's updated adjustment that is associated with the White River hydroelectric project that was previously discussed in my testimony pursuant to Schedule B-1. After the Company's original filing, PSE updated its proposed White River adjustment to reflect (1) net proceeds received that related to a timber contract on the White River property, and (2) an update to incorporate the February 28, 2017, balance of the regulatory asset accounts to reflect charges related to prior sales of White River surplus properties.[14] The impact of these adjustments to the White River regulatory asset results in a change to the associated amortization expense.

Q: How did you reflect the Company's revised amortization of the White River regulatory asset in the determination of your recommended net operating income?

A: As shown on Exhibit RCS-3, Schedule C-10, for electric operations, incorporating the Company's updated amortization of the White River regulatory asset decreases amortization expense by $135,536. This adjustment does not apply to gas operations.

K. C-11, Production Expense Adjustment (Electric)

Q: Please explain the adjustment for Production Expense.

A: As previously discussed in my testimony pursuant to Exhibit RCS-3, Schedule B-2, for electric operations the Company proposed a production adjustment, which decreased certain production expenses by the load and customer production factors that PSE used to calculate power costs. Specifically, the Company applied

[14] *See* Barnard, Exh. KJB-10T, at 10.

this proposed adjustment to production related items to reduce the expense levels because PSE anticipates recovery of these expenses will be offset by expected load or customer growth between the test year and the rate year. As originally proposed, PSE's production adjustment reduced net operating income for electric operations by $3,130,918.[15]

As discussed on page 11 of her Prefiled Supplemental Direct Testimony, PSE witness Ms. Barnard supplemented the Company's proposed adjustment to reflect the update to the White River regulatory assets discussed above pursuant to Schedule B-1. As shown on Exhibit RCS-3, Schedule C-11, for electric operations, the Company's update to production costs increases pre-tax operating expenses by a net amount of $2,502.

L. C-12, Depreciation & Amortization Expense Under Proposed New Depreciation Rates (Electric and Gas)

Q: Please explain your adjustment to depreciation and amortization expense.

A: This adjustment reflects the impacts on depreciation and amortization expense of the new depreciation rates that are being recommended by Public Counsel witness Ms. McCullar. As shown on Exhibit RCS-3, Schedule C-12, for electric operations, this adjustment reduces PSE’s proposed depreciation expense by $27,137,608.

Similarly, as shown on Exhibit RCS-4, Schedule C-12, for gas operations, this adjustment reduces PSE’s proposed depreciation expense by $16,831,098.

[15] *See* Barnard, Exh. KJB-10T at 60-62.

Q: Did the adjustment to depreciation expense for new depreciation rates impact rate base?

A: Yes. As discussed previously in my testimony, these adjustments to depreciation expense for new depreciation rates resulted in related adjustments to accumulated depreciation and ADIT for PSE's electric and gas operations that are reflected in Exhibit RCS-3, Schedules B-3 and B-4, respectively, for electric utility operations, and in Exhibit RCS-4, Schedules B-3 and B-4 for gas utility operations.

M. C-13, Interest Synchronization (Electric and Gas)

Q: Please explain the interest synchronization adjustment.

A: The interest synchronization adjustment applies the weighted cost of debt to the adjusted rate base to derive the interest deduction applicable to the calculation of test year income tax expense. My overall recommended rate base for PSE's electric and gas operations differ from the Company's requested amounts. This results in an adjustment to the amount of synchronized interest included in the income tax calculation for PSE's electric and gas utility operations. The calculations of the interest synchronization adjustment for PSE's electric and gas operations are shown on Schedule C-13 of Exhibits RCS-3 and RCS-4, respectively.

N. C-14, Pension Expense (Electric and Gas)

Q: Please explain the Company's requested pension expense.

A: As discussed on pages 18-19 in the Prefiled Direct Testimony of Company witness Ms. Free, the Company has calculated pension expense based on a four-year average of cash contributions to PSE's qualified pension fund. Specifically, the Company made cash contributions totaling $86.1 million to its qualified pension plan for the four-year period ending September 30, 2016. From this amount, PSE calculated a four-year average of $21.5 million. The Company allocated that amount to O&M expense based on wage distributions. PSE then allocated the O&M expense amount between electric and gas operations based on its direct labor allocator. PSE's proposed adjustment increased test year O&M expense by $1.8 million and $0.880 million for electric and gas operations, respectively.[16]

Q: What is the Company's basis for using a four-year average of cash contributions in its determination of pension expense?

A: On page 19 of her Prefiled Direct Testimony, Ms. Free states:

> In the 2009 general rate case, the Commission affirmed that the actual four-year average of cash contributions ending with the historical test year should be used for setting rates. Using cash contributions instead of expenses recognized under the Financial Accounting Standards Board Accounting Standards Codifications allows for consistency when applying this adjustment.[17]

Q: Do you agree with the Companies' proposed calculation of pension expense?

---

[16] *See* Free, Exh. SEF-1T, at 19; Barnard, Exh. KJB-4; and Free, Exh. SEF-4.
[17] Free, Exh. SEF-1T, at 19.

A: No, I do not agree with PSE's proposed calculation for several reasons, which I will explain below. I am recommending that the pension expense allowance for the rate year be set at $18.4 million.

Q: Please discuss how the Commission determined PSE's allowance for pension expense in the 2009 rate case.

A: In its Order 11 in Docket Nos. UE-090704 and UG-090705, the Commission stated at page 31, paragraphs 79 and 80, the following:

> We find that the actual four-year average pension expense ending December 31, 2008, provides a reasonable measure of the amount of pension expense that should be allowed for recovery in rates. This approach has been reliably used in recent cases and it provides at least some degree of normalization with respect to contributions that have tended to be highly variable from year to year. PSE's use of projected 2009 contributions is similar in some respects, but does not satisfy the known and measurable standard.
>
> We do not find FEA's case for moving to an actuarial basis for measuring this expense sufficiently developed to apply it in this case, **but a more fully developed record could convince us to order such a change in a future proceeding**.[18]

Q: Do you believe that a more fully developed record exists in the current proceeding which supports your recommendation that PSE's pension expense allowance in this rate case be established at $18.4 million per year?

A: Yes, I do. I explain my reasoning below in this section of my testimony.

Q: What type of qualified pension plan does PSE offer its employees?

[18] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-090704 & UG-090705, Order 11, ¶¶ 79-80 (Apr. 2, 2010) (emphasis added).

A: PSE offers a defined benefit pension plan to its employees.[19]

Q: What is a defined benefit pension plan?

A: There are two general types of pension plans: (1) defined benefit pension plans and (2) defined contribution plans. In a defined benefit pension plan employees accrue benefits during their years of service and receive specified benefits in the form of an annuity or lump sum, after they retire, and the employer bears the risk of investment market fluctuations and assuring that there are sufficient funds available to pay the pensioners at the specified level. In contrast, in defined contribution pension plans, such as 401(k) savings plans or money purchase pension plans, employees and employers make contributions at a predefined level and employees bear the risk of investment market fluctuations in the value of their investments.

Q: What is FAS 87?

A: FAS 87 is an accounting standard promulgated by the Financial Accounting Standards Board ("FASB") in December 1985 relating to employer's accounting for pensions. It has been codified in the Accounting Standards Codification ("ASC") as ASC 715. For purposes of this testimony, I will generally refer to this as FAS 87 rather than ASC 715.

Q: What is net periodic pension cost?

[19] See Confidential Attachment A, Appendix A, page A-1 to the response to ICNU Data Request No. 057, which is the most recent actuarial report for the Retirement Plan for Employees of PSE. This is included in Exhibit RCS-8C.

A: As it pertains to a defined benefit pension plan, net periodic pension cost is the amount recognized in an employer's financial statement as the cost of the pension plan for the period. Put another way, the net periodic pension cost is the annual accounting expense or income a company must recognize in their income statement, and direct adjustments to the plan sponsor's balance sheet, if applicable.

Q: What are the components of net periodic pension cost under FAS 87?

A: Under FAS 87, the net periodic pension cost is the sum of the following components:

- **Service cost**, which is the value of the benefits earned, or accrued, during the current year based on the applicable benefit formula for each participant.
- **Interest cost**, which represents the interest on the pension plan liability (i.e., Projected Benefit Obligation, or "PBO") for the year. This amount increases pension cost and reflects the passage of time or the time value of money on the PBO.
- **Expected return on assets for the year**, which reduces pension cost and is based on applying an expected rate of return to pension trust assets. Differences between the actual return on assets and the expected return on assets represent an actuarial gain or loss that will be recognized in future pension cost.
- **Amortizations of unrecognized costs and gains**, which can include amortizations related to changes in liability due to plan changes, changes in actuarial assumptions used to value plan liabilities, differences between expected and actual asset returns, and/or experienced gains or losses to be recognized over time and subject to amortization. The amortization period is not to exceed the average future lifetime of plan participants. Prior Service Cost amortization is generally the cost of retroactive benefits granted in a plan amendment. Retroactively increasing benefits increases the PBO and prior service cost at the date of amendment and vice-versa. The increased (or decreased) cost is amortized as a component of net periodic pension cost. Amortization can be done on straight line basis that amortizes cost over the average remaining service life of the active employees. Actuarial gains and losses occur due to changes in actuarial assumptions. Gains decrease and losses increase the pension cost. There are two components of gains/losses:

> (1) the current period difference which is the difference between actual and expected return (expected rate of return on plan assets times the market related value of plan assets) and (2) the amortization of the unrecognized gain/loss for previous periods. In amortizing unrecognized gains or losses, a 10 percent corridor is allowed to be used in which only those gains or losses in excess of the greater of 10 percent of the PBO or the market-related value of assets are subject to amortization.

Q: When FAS 87 was initially adopted for financial reporting purposes, was there also a transitional component of the net periodic pension cost?

A: Yes. When FAS 87 was promulgated by the FASB in December 1985, it also included a component of net periodic pension cost for Amortization of Transition Benefit Asset (decrease) or Obligation/Liability (increase) to pension cost. The Transition Benefit (or Obligation) amount was based on the funded status of the defined benefit pension plan, when FAS 87 was initially adopted for financial reporting purposes. The employer recorded the amortization of the Transition Benefit Obligation ("TBO") over average remaining service of plan employees, or over a 15-year period if the service period was less than 15 years. Most companies are now beyond the TBO amortization periods, so TBO amortization would generally no longer be a component of a utility's net periodic pension cost.

Q: Have companies been required to use FAS 87 for accounting purposes for defined benefit pensions?

A: Yes. As noted above, in December 1985, the FASB issued FAS 87. FAS 87 provided guidance as to how companies would recognize costs associated with defined benefit pension plans for financial statement reporting purposes, effective for fiscal years beginning after December 15, 1986. Prior to the issuance of FAS 87, the amount of pension costs recorded by a company for financial statement purposes was generally equal to the level of contributions actually made into the pension trust fund.[20] As a result of FAS 87, the FASB determined that pension costs reported for financial statements purposes would not automatically be equal to the pension trust fund contribution, breaking the historical linkage between financial reporting of net periodic pension costs (expense and capital)[21] and pension funding contributions.

Q: Did FAS 87 dictate a particular ratemaking treatment?

A: No. FAS 87 provided accounting guidance with respect to the financial accounting disclosure of pension costs, related assets, and liabilities. FAS 87 neither prescribes, nor imposes any regulatory guidance or authoritative ratemaking treatment for the net periodic pension cost or for the prepaid pension asset or pension liability. FAS 87 set forth the required framework for all publicly traded companies to quantify and record net periodic pension costs.

[20] The pension fund is **separate** from the utility's financial statements. The monies in the pension fund are held by the pension trustee. The utility's contributions (i.e., monies deposited) to the pension fund are invested by the pension trustee to ensure that the fund balances are sufficient to pay future pension obligations to the utility's employees.

[21] The full amount of net periodic pension cost determined by the Company's actuary is initially recorded in expense Account No. 926, Employee Pensions and Benefits. The portion of net periodic pension cost that is capitalized to plant or billed to others is recorded in a contra-expense to Account No. 926, Employee Benefits Transfer. This latter account recognizes that a pro-rata portion of employee benefits are attributable to the labor costs that are charged to capitalized construction projects and eventually to utility plant in service.

Q: What is the usual source for the amounts recorded by a company on its books for its net periodic pension cost for a defined benefit pension plan?

A: It is typically an actuarial report. Each year, with assistance from its actuarial consultants, the employer providing the defined benefit pension plan would record a journal entry in its accounting records in order to accrue the net periodic pension cost pursuant to FAS 87. The actuarial consultants may also provide assistance in quantifying the range in pension contributions that are required or permitted under existing regulations.[22]

Q: How have the minimum funding levels for a defined benefit pension plan generally been determined?

A: Prior to 2008, the Employee Retirement Income Security Act (ERISA) specified the minimum required funding requirements.[23] ERISA is a federal law that established minimum standards for pension plans in private industry and provides for extensive rules on the federal income tax effects of transactions associated with employee benefit plans. ERISA was enacted to protect the interests of employee benefit plan participants and their beneficiaries by: [24]

- Requiring the disclosure of financial and other information concerning the plan to beneficiaries;
- Establishing standards of conduct for plan fiduciaries;
- Providing for appropriate remedies and access to the federal courts.

[22] This information may include minimum required funding contributions and the maximum tax-deductible contributions.

[23] Pub.L. 93–406, 88 Stat. 829, enacted September 2, 1974, codified in part at 29 U.S.C. Ch. 18.

[24] *See*, U.S. Dept. of Labor, Employee Benefits Security Administration, *Retirement Plans and ERISA FAQs*, https://www.dol.gov/agencies/ebsa/about-ebsa/our-activities/resource-center/faqs/retirement-plans-and-erisa-consumer (last visited Jun. 28, 2017).

Q: Does ERISA require that pensions be provided in a defined benefit plan?

A: No. ERISA does not require employers to establish pension plans. Likewise, as a general rule, ERISA does not require that pension plans provide a minimum level of benefits. Instead, ERISA regulates the operation of a pension plan once it has been established. Under ERISA, pension plans must provide for vesting of employees' pension benefits after a specified minimum number of years. ERISA requires that the employers who sponsor plans satisfy certain minimum funding requirements. ERISA also regulates the manner in which a pension plan may pay benefits. For example, a defined benefit plan must pay a married participant's pension as a "joint-and-survivor annuity" that provides continuing benefits to the surviving spouse unless both the participant and the spouse waive the survivor coverage.

Q: How has ERISA helped assure that defined benefit pension plans would have sufficient assets from which to pay benefits?

A: Among other things, ERISA established the Pension Benefit Guaranty Corporation ("PBGC") to provide coverage in the event that a terminated defined benefit pension plan does not have sufficient assets to provide the benefits earned by participants. Later amendments to ERISA require an employer who withdraws from participation in a multi-employer pension plan with insufficient assets to pay all participants' vested benefits to contribute the pro rata share of the plan's unfunded vested benefits liability.

Under ERISA, minimum funding requirements were also established for defined benefit plans.[25] Under ERISA, a defined benefit pension plan maintained a “funding standard account,” which was charged annually for the cost of benefits earned during the year and credited for employer contributions. Increases in the plan's liabilities due to benefit improvements, changes in actuarial assumptions, and any other reasons were amortized and charged to the account. Decreases in the plan’s liabilities were amortized and credited to the account. Every year, the employer was required to contribute the amount necessary to keep the funding standard account from falling below zero at year-end. Minimum annual funding requirements are therefore sometimes referred to as the ERISA funding requirement or the ERISA minimum.

Q: Are the minimum funding requirements for a defined benefit pension plan now also impacted by another act?

A: Yes. The Pension Protection Act of 2006 (“PPA”) included additional funding requirements to improve the benefit security provided by defined benefit pension plans. The PPA redefined minimum required cash funding requirements for defined benefit pension plans for 2008 and beyond.

Q: Please describe the general funding requirements for a defined benefit pension plan under the PPA.

[25] By their nature, defined contribution plans are always fully funded, even if the employee has not yet become vested in the employer contributions.

A: In 2008, when the PPA funding rules went into effect, single-employer defined benefit pension plans no longer maintain funding standard accounts. The funding requirement under PPA is basically that a plan must stay fully funded (that is, its assets must equal or exceed its liabilities). If a plan is fully funded, the minimum required contribution is the cost of benefits earned during the year. If a plan is not fully funded, the contribution also includes the amount necessary to amortize over seven years the difference between its liabilities and its assets. Stricter rules apply to severely underfunded plans (called "at-risk status").

The PPA has different funding requirements for multi-employer pension plans, which preserve most of the pre-PPA funding rules including the funding standard account. Under the PPA, increases and decreases in the plan's liabilities will be amortized, but the amortization period for benefit improvements adopted after 2007 will be shortened. As with single-employer plans, multi-employer pension plans that are significantly underfunded are subject to restrictions. The restrictions, which may limit the plan's ability to improve benefits or require the plan to reduce employees' benefits, vary depending whether a pension plan's funding status is termed "endangered," "seriously endangered," or "critical." The restrictions accompanying each deficient funding status are progressively more severe as funding status worsens.

In general, the PPA requires a sponsor of a defined benefit pension plan to contribute into the plan annually an amount equal to: (1) the benefits being earned for the year, plus (2) a seven-year amortization of the amount the plan is underfunded. The seven-year amortization base is established each year based on the difference between the funded status of the plan and the value of the previous seven-year amortization bases that still exist. Once the plan becomes fully funded, all amortization bases are eliminated and the required contribution simply becomes the benefits being earned for the year. This is sometimes referred to as the "normal cost." If the plan becomes overfunded by more than the benefits being earned for the year, no new funding contribution is required for that year. Contributions are typically to be made on a quarterly basis. More frequent funding (e.g., monthly) is not prohibited. A final contribution for the year is generally allowed to be made up to eight and one-half months after the end of the plan year.

Q: Please explain the concept of the maximum tax deductible contribution for funding of a defined benefit pension plan.

A: The Internal Revenue Code contains provisions limiting the maximum tax deduction for contributions made to fund various types of retirement benefits, including defined benefit pension plans.

Q: Can you provide an explanation of how the maximum tax deductible contribution for a defined benefit pension plan is generally determined?

A: Generally, an actuary will provide the plan sponsor with information on both (1) the minimum funding obligation (representing the lowest amount needed to meet the minimum funding obligation, as discussed above) and (2) the maximum tax-deductible funding contribution. The latter generally involves actuarial calculations, which can be quite complex, to derive a "full funding limitation."

Basically, two provisions determine the maximum amount an employer can contribute and take as a deduction to a qualified pension plan in any one taxable year.

The first of these rules permits a deduction for a contribution that will provide, for all employees participating in the plan, the unfunded cost of their past and current service credits distributed as a level amount or as a level percentage of compensation over the remaining future service of each such employee. If this rule is followed, and if the remaining unfunded cost for any three individuals is more than 50 percent of the total unfunded cost, the unfunded cost attributable to such individuals must be distributed over a period of at least five taxable years. Contributions under individual policy pension plans are typically claimed under this rule.

The second rule, while occasionally used with individual policy plans, is used primarily in group pension and trust fund plans. This rule permits the employer to deduct the normal cost of the plan plus the amount necessary to amortize any past service or other supplementary pension or annuity credits in equal annual installments over a 10-year period. However, the maximum tax-deductible limit cannot exceed the amount needed to bring the plan to its full-funding limit. The full-funding limit is defined as the lesser of 100 percent of the plan's actuarial accrued liability (including normal cost) or 150 percent of the plan's current liability, reduced by the lesser of the market value of plan assets on their actuarial value. If the plan's actuarial cost method does not generate an accrued liability, the value that would be generated by the entry age normal method is used. The plan's funding standard account credit balance is subtracted from the asset value before determining the full-funding limitation.

Q: Do other income tax considerations also apply?

A: Yes. If amounts contributed in any taxable year are in excess of the amounts allowed as a deduction for that year, the excess may be carried forward and deducted in succeeding taxable years, in orders of time, to the extent that the amount carried forward to any such succeeding taxable year does not exceed the deductible limit for such succeeding taxable year. However, a 10 percent excise tax is imposed on nondeductible contributions by an employer to a qualified plan. For purposes of the excise tax, nondeductible contributions are defined as the sum of (1) the amount of the employer's contribution that exceeds the amount deductible under Internal Revenue Code section 404 and (2) any excess amount contributed in the preceding tax year that has not been returned to the employer or applied as a deductible contribution in the current year.

Additionally, obtaining benefit from taking an income tax deduction for pension funding contributions can also be impacted by other deductions and whether the company has taxable income against which to take a deduction.

Q: Does utility management generally have a wide range of discretion as to how much to contribute to funding a defined benefit pension plan in a given year?

A: Yes. Utility management's discretion as to how much funding to contribute into the defined benefit pension plan trust for a given year is generally confined by (1) the minimum funding obligation (representing the lowest amount needed to meet the minimum funding obligation, as discussed above) and (2) the maximum tax-deductible funding contribution (which can represent the maximum amount to be considered for the pension funding contribution). Contributions above the minimum funding obligation and up to the maximum tax deductible amount for the year are sometimes referred to as discretionary contributions. For larger pension plans, this range of potential discretionary contributions can amount to hundreds of millions of dollars.

Q: Can management's decisions on how much to contribute into a defined benefit pension plan also impact the amount of net periodic pension cost in a year?

A: Yes, it can. Generally, the most directly impacted component of net periodic pension cost is the expected return on assets for the year. As I discussed above, the expected return on plan assets is derived by applying an expected rate of return to pension trust assets. The expected return on plan assets reduces the net periodic pension cost.

Q: How should the cost of PSE's defined benefit pension plan be reflected in rates in the current rate case?

A: I recommend that the allowance for pension expense in the current PSE rate case be limited to the average annual net periodic pension cost costs determined pursuant to FAS 87 for the four year period ending December 31, 2016, as allocated to expense, as allocated between PSE's electric and gas operations. As shown on Exhibit Nos. RCS-3 and RCS-4, Schedule C-14, prior to such allocations, the four-year average net periodic pension cost is approximately $18.4 million.

Q: Why should a four-year average be used?

A: A four-year average should be used because such an average appears to be consistent with Commission practice,[26] and it helps smooth out or "normalize" the expense allowance for ratemaking purposes. I note that the Company is also proposing to use a four-year average, but the Company's proposal is based on historic funding contributions for the period September 30, 2013, through September 30, 2016, which if used in the current general rate case, would significantly overstate the 2018 rate year pension expense.

Q: Why is the FAS 87 accounting preferable to using a four-year average of cash contributions for pension expense?

[26] *See, Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-090704 & UG-090705, Order 11, ¶ 79 (Apr. 2, 2010).

A: Recognition of pension costs for ratemaking for most utilities is typically based on some variant of FAS 87 cost. The use of a backward looking historical period of cash funding contributions as the basis for ratemaking recognition of utility pension cost as PSE proposes (although allowed by the Commission in past PSE rate cases), is inconsistent with generally accepted accounting principles ("GAAP") and would result in overstating PSE's pension expense for an extended period. PSE's proposed pension expense in the current case exceeds estimates for 2018 and other years, as I explain below.

Q: Would PSE's proposed four-year average of cash contributions result in the Company's pension expense being significantly overstated on a going forward basis?

A: Yes. The chart below reflects the data that was compiled from confidential Company Exhibit TMH-7C,[27] which was filed in conjunction with the Prefiled Direct Testimony of PSE witness Thomas H. Hunt.

/ /

/ / /

/ / / /

/ / / / /

[27] The response to WUTC Staff Data Request No. 212 states that PSE's actuarial firm, Milliman, prepared the materials included in confidential Exhibit TMH-7C and that the assumptions used by Milliman were consistent with those used in their 2016 actuarial valuation of PSE's pension plan. Exhibit 8C contains a copy of PSE's response to WUTC Staff Data Request No. 212.

[redacted],[28] [redacted]

[28] This chart is also being presented as Confidential Exhibit RCS-12C.

[redacted].

My recommended use of a four-year average of net periodic pension cost is generally in line with the Company's projected cash contributions. Therefore, the use of the FAS 87 amounts for pension expense is the preferable method and should be applied in the current PSE rate case.

Q: What is your recommendation for the pension expense allowance in PSE's current general rate case?

A: I recommend a pension expense allowance of $18.4 million per year. This is based on a four-year average of net periodic pension cost for years 2013 through 2016, and also has taken into consideration the Company's projections. As shown on Exhibit RCS-3, Schedule C-14, for electric operations, my recommended adjustment to pension expense reduces O&M expense by $1.151 million. As shown on Exhibit RCS-4, Schedule C-14, for gas operations, my recommended adjustment to pension expense decreases O&M expense by $0.556 million.

O. C-15, Environmental Remediation Expense (Electric and Gas)

Q: Please explain the Company's proposed environmental remediation expense adjustment.

A: As discussed on page 23 of the Prefiled Direct Testimony of Company witness Ms. Free, PSE has used deferred accounting for its environmental remediation costs and related recoveries since the early 1990s.[29] As it relates to the recovery of the Company's net deferred environmental remediation costs, Ms. Free references the Commission's Final Order in Docket No. UE-070724, where at paragraph 6 (e) it states:

> Allowed net deferred costs will be amortized over a five year period on the date all costs, net of recoveries, become known and declared prudent. The deferrals will be consistent with the Commission's Merger Order in Docket UE-960195.[30]

In terms of the environmental remediation costs that PSE is requesting for recovery in this proceeding, Ms. Free outlined the following on pages 24-25 of her Prefiled Direct Testimony:

> 1. Only actual costs are being requested for recovery. PSE included actual costs through September 30, 2016.[31]
>
> 2. In order to maintain insurance and third-party recoveries to offset future remediation costs on existing environmental sites, PSE is proposing to include only a portion of the unassigned insurance and third-party recoveries to offset the actual costs included in this proceeding.
>
> . . .
>
> 3. Consistent with paragraph 6 (e) of the Commission's Final Order in Docket No. UE-070724, PSE is requesting a five-year amortization period for the net deferred costs.

[29] See Prefiled Direct Testimony of PSE witness John K. Rork, Exh. JKR-1T, for a discussion of the history of the Company's environmental remediation activities.

[30] *In re: Puget Sound Energy For An Accounting Order Regarding the Accounting Treatment for Costs of its Elec. Env't Remediation Program,* Docket UE-070724, Order 01, ¶ 6 subpart (e) (Oct. 8, 2008).

[31] Ms. Free stated that these costs will be updated to more current amounts throughout this proceeding, but PSE did not update its proposed environmental remediation adjustment for either electric or gas operations in its supplemental filing dated April 3, 2017.

The Company's proposed environmental remediation adjustment increases O&M expense by $1.423 million for electric operations and by $8.561 million for gas operations.

Q: Are PSE's environmental remediation efforts required by law?

A: Yes. As discussed on page three of the Prefiled Direct Testimony of Company witness John K. Rork, PSE's environmental remediation efforts are governed by the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") under federal statute[32] and by the State of Washington's Model Toxics Control Act ("MTCA") under state statute.[33]

Q: Since PSE's environmental remediation efforts began, what is the total amount of proceeds received from insurance and third parties?

A: As of September 30, 2016, the Company has received proceeds from insurance carriers and third parties totaling $5.344 million for environmental remediation sites related to electric operations and $50.268 million for environmental remediation sites related to gas operations, for total recoveries of $55.612 million.[34]

---

[32] *See*, U.S. Environmental Protection Agency, *Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and Federal Facilities*, https://www.epa.gov/enforcement/comprehensive-environmental-response-compensation-and-liability-act-cercla-and-federal (last updated on Feb. 16, 2017).

[33] *See*, RCW 70.105D, Hazardous Waste Cleanup-Model Toxics Control Act.

[34] *See*, Rork, Exh. JKR-3.

Q: Do the proceeds referenced above represent actual insurance and third-party recoveries?

A: Yes. According to the response to WUTC Staff Data Request No. 284,[35] the electric and gas related proceeds totaling $55.612 million reflect actual recoveries received by PSE as of September 30, 2016, and do not represent future remediation or monitoring obligations.

Q: You previously stated that PSE proposes to only include a portion of its unassigned insurance and third-party recoveries to offset the actual environmental remediation costs in this proceeding. Please explain.

A: As shown on PSE Adjustment No. 6.19E, the Company is proposing to offset deferred environmental remediation costs totaling $9.596 million for electric related sites by only $2.484 million, or approximately 46 percent of the $5.344 million in proceeds received from insurance carriers and third-parties.

As shown on PSE Adjustment No. 6.19G, the Company is proposing to offset deferred environmental remediation costs totaling $72.192 million for gas related sites by only $29.385 million, or approximately 58 percent of the $50.268 million in proceeds received from insurance carriers and third-parties.

Q: Has PSE explained its rationale for proposing to include only a portion of the proceeds from insurance carriers and third-parties as an offset against the

---

[35] Exh. No. RCS-9.

actual deferred environmental remediation costs being requested for recovery?

A: Yes. In its response to WUTC Staff Data Request No. 278,[36] the Company stated:

> Puget Sound Energy ("PSE") has substantially exhausted many available policies and believes the prospect of additional significant recoveries is low. Because current future cost estimates exceed potential additional recoveries, PSE has proposed to retain a portion of its existing recoveries to help offset additional remediation costs in the future. In addition, there are a small number of sites where PSE regularly receives proceeds from third parties. These recoveries are directly applied to each specific site to offset costs incurred.
>
> PSE had concerns about intergenerational inequities that could occur if the entire amount of proceeds were used to offset actual costs and thought it best to reserve a portion of the proceeds to ensure that some recoveries would be available to address the remediation associated with projects that are still early in the remediation process. As a result, PSE relied on existing Generally Accepted Accounting Principles ("GAAP") under Financial Accounting Standards Board Accounting Standards Codification No. 410-30-25 Asset Retirement and Environmental Obligations ("ASC 410-30-25"), which requires recognition of liabilities associated with environmental liabilities. PSE utilized this existing GAAP requirement to determine a reasonable estimate of what the total net environmental costs would be by adding the mid-range of the future cost estimate to the existing net environmental costs as of September 30, 2016. The proportion of the net environmental costs incurred through September 30, 2016 to the total net environmental costs was used to determine the proportion of unallocated insurance and third party proceeds to pass back in the current proceeding. Conversely, the remaining portion would be held to apply against the future costs yet to be incurred, for which ASC 410-30-25 provides a reasonable estimate.

[36] Exh. No. RCS-9.

As shown in the table below, it is through the process described in the above passage that PSE calculated the percentages it has applied to the proceeds it has received from insurance carriers and third parties:

Line No.	Description	Low Future Costs	High Future Costs	Mid-Range Future Costs
1	Gas	$ 37,855,000	$ 64,749,500	$ 51,302,250
2	Electric	$ 5,111,000	$ 16,996,500	$ 11,053,750
3	Total Estimated Electric and Gas Future Cost Estimate	$ 42,966,000	$ 81,746,000	$ 62,356,000
		Electric	Gas	
4	Total Deferred Costs Requested for Recovery	$ 9,596,412	$ 72,192,483	
5	Mid-Range of Future Costs	$ 11,053,750	$ 51,302,250	
6	Total Cost Estimate	$ 20,650,162	$ 123,494,733	
7	Percentage to Allocate a Pro-Rata Share of Insurance and Third-Party Proceeds	46%	58%	

Source: Workpapers filed with Adjustment No. 6.19 (E&G)

Q: Do you agree with the Company's rationale for its proposal to retain a portion of existing recoveries to offset potential remediation costs in the future?

A: No, I do not. As previously noted, PSE's response to WUTC Staff Data Request No. 284[37] stated that proceeds received from insurance carriers and third parties which totaled $55.612 million are <u>actual recoveries</u> received as of the September 30, 2016, the end of the test year. The actual deferred environmental remediation costs and the actual proceeds received from insurance carriers and third parties reflect known and measurable amounts as of the end of the test year. In contrast, the future environmental remediation costs to which PSE proposes to allocate a portion of the actual recoveries to are estimates. The mismatch

[37] Exh. No. RCS-9.

proposed by PSE should be corrected by offsetting actual environmental remediation costs incurred through the test year with the actual insurance and third-party recoveries received through the end of the test year.

Q: What is your recommendation?

A: I recommend that 100 percent of the proceeds received from insurance carriers and third parties through the test year be used to offset the actual deferred environmental remediation costs as of September 30, 2016. This contrasts with PSE's proposal to only use 46 percent of the electric related proceeds and 58 percent of the gas related proceeds to offset environmental remediation costs through the end of the test year. As shown on Exhibit RCS-3, Schedule C-15, for electric operations, my recommended adjustment decreases O&M expense by $0.572 million. As shown on Exhibit RCS-4, Schedule C-15, for gas operations, my recommended adjustment decreases O&M expense by $4.176 million.

P. C-16, Credit Card Payment Processing Costs

Q: Please explain the Company's proposed adjustment related to payment processing costs.

A: As discussed on page 38 of the Prefiled Direct Testimony of Company witness Ms. Barnard, PSE proposes to incorporate the provisions of Commission Order 01 from Docket Nos. UE-160203 and UG-160204, whereby the Company was authorized to defer for future recovery the costs associated with customers' use of debit and credit cards to pay their bills. Specifically, the Commission's Order, dated March 24, 2016, authorized PSE to defer the costs incurred until the beginning of the rate year in its next general rate case proceeding. In addition, the Commission's Order also allowed PSE to recover credit card processing fees incurred during the rate year in its next rate case.

Q: What are the specific components of PSE's proposed adjustment?

A: As discussed on pages 38 and 39 of Ms. Barnard's testimony, there are three components to the Company's proposed adjustment. The first component relates to the amortization of the costs that were deferred prior to the rate year. The Company's proposed deferred balance is based on (1) actual debit and credit card fees from August 31, 2015, through September 30, 2016, and (2) estimated costs from October 2016 through December 2017.[38] PSE is requesting to recover the entire deferred balance over one year.

The second component of the Company's proposed adjustment is that PSE included an estimate of the costs PSE will incur during the rate year period of January through December 2018. This estimate is based on the actual average cost per transaction as of September 30, 2016, which was then applied to the estimated number of transactions during the rate year. Similar to the deferral balance, Ms. Barnard stated in her Prefiled Direct Testimony that the estimated rate year cost per transaction and number of transactions will be updated during

[38] On page 39 of her Prefiled Direct Testimony, Ms. Barnard stated that the costs included in the deferral balance will be trued-up during the course of this proceeding, but the Company did not update its proposed adjustment for credit card payment processing costs in its supplemental filing dated April 3, 2017.

the course of this proceeding. However, the Company did not update its proposed adjustment in its April 3, 2017, supplemental filing.

The third component of the Company's proposed adjustment incorporates the impact of a new service agreement between PSE and its third-party payment processor Fiserv, which became effective on October 31, 2016, and which decreases the overall costs for processing non-credit card and debit card transactions by approximately $365,000 for electric and gas operations.

The overall impact of PSE's proposed adjustment is to increase O&M expense by $4.750 million for electric operations and $3.424 million for gas operations.

Q: Do you agree with the Company's proposed adjustment to credit card payment processing costs?

A: Not entirely. While I agree conceptually with the Company's proposed adjustment relative to the provisions of the Commission's Order in Docket Nos. UE-160203 and UG-160204, I disagree with PSE's proposed one-year amortization period for the deferred balance.

Q: Does the Commission's Order in Docket Nos. UE-160203 and UG-160204 address the amortization period to be used for recovering the deferred balance?

A: No. The Commission's Order in Docket Nos. UE-160203 and UG-160204 does not address the amortization period to be used for recovering the deferred balance.

Specifically, on page 3 of the Commission's Order, the first directive under the "Order" section states:

> Puget Sound Energy's Amended Petition to defer, for later recovery in rates, the costs incurred to offer a fee-free payment program for its residential and small business customers, including customers who pay with a credit and debit card is granted.[39]

As noted in the passage above, the Commission authorized the recovery of the deferred balance, but did not specifically authorize the Company to use a one-year amortization period for the deferred balance.

Q: What amortization period do you recommend for the deferral portion of the Company's proposed adjustment?

A: I recommend that the deferred cost for such fees through December 31, 2017, be amortized over three years rather than one year as proposed by PSE. By amortizing the deferred balance over three years, the impact of these costs on ratepayers will be mitigated while still allowing the Company recovery of the deferred credit card payment processing costs as approved by the Commission in Order 01 in Docket Nos. UE-160203 and UG-160204.

Q: What impact does your recommended adjustment have on PSE's 2018 rate year operating expenses?

A: As shown on Exhibit RCS-3, Schedule C-16, my recommended adjustment decreases 2018 rate year O&M expense by $1.657 million for electric operations.

---

[39] *In re: Puget Sound Energy For An Order Authorizing Accounting and Ratemaking Treatment of Fees for Payments Made by Residential and Small-Business Customers*, Dockets UE-160203 & UG-160204, Order 01: Order Granting Amended Accounting Petition, ¶ 14 (Mar. 24, 2016).

As shown on Exhibit RCS-4, Schedule C-16, my recommended adjustment decreases 2018 rate year O&M expense by $1.195 million for gas operations.

V. COLSTRIP ISSUES

A. Colstrip Background

Q: Please provide some background on the Colstrip generating station.

A: The Colstrip power plant is located in Montana and consists of four coal-fired generating units capable of producing up to 2,094 megawatts of electricity. The plant is co-owned by PSE and others (as discussed below), and is operated by Talen Energy (Talen).[40] The Prefiled Direct Testimony of PSE witness Ronald Roberts provides an overview of Colstrip ownership and operation. A review of Talen Energy's web page states as follows concerning the Colstrip plant:

> Plant Details
>
> The Colstrip power plant, east of Billings, operates four coal-fired generating units capable of producing up to 2,094 megawatts of electricity. Units 1 and 2 began commercial operation in 1975 and 1976, and units 3 and 4 started in 1984 and 1986. Units 1 and 2 each have about 307 megawatts of generating capacity; Talen Energy has 50 percent ownership of each. Units 3 and 4 each have about 740 megawatts of generating capacity; Talen Energy has 30 percent ownership in Unit 3 and no ownership in Unit 4. Talen Energy's share in the plant's generating capacity is 529 megawatts. The plant employs about 360 people and is owned by Talen Energy LLC, Puget Sound Energy Inc., Portland General Electric Company, Avista Corporation, PacifiCorp and NorthWestern Energy. Low-sulfur coal and state-of-the-art scrubbers restrict sulfur dioxide emissions to less than levels required by the Clean

[40] In December 2016, Talen Energy was acquired by Riverstone Holdings LLC ("Riverstone") and changes to the executive management were made. *See*, e.g., PSE's response to Sierra Club Data Request No. 16, Att. A, "Colstrip Strategic Planning Update" dated March 2, 2017, attached as Exhibit RCS-11C.

> Air Act. The plant also meets Environmental Protection Agency standards for nitrogen oxides emission. **The plant consistently ranked as one of the lowest-cost fuel plants in the Western Electricity Coordinating Council, a regional member of the North American Electricity Reliability Council that includes all the western states and the Canadian provinces of Alberta and British Columbia**.[41]

Public Counsel asked PSE about the highlighted statement in Public Counsel Data Request No. 394, which is included in Exhibit RCS-10C. PSE's response indicated that the statement was made by Talen Energy not by PSE. The Company's response stated further that: "Talen and PSE are separate, privately held companies. PSE does not have information on what criteria or report Talen may have relied on to make the statement."

PSE was also asked in Public Counsel Data Request No. 394(b) concerning whether the Colstrip Plant is expected to continue to be ranked as one of the lowest-cost fuel plants in the Western Electricity Coordinating Council. PSE responded similarly, however, stating only that: "Since the claim referenced above was by Talen and not PSE, PSE cannot comment on the continuation of the statement made by Talen."

Q: Please discuss the ownership of the Colstrip Plant.

A: Talen Energy, now owned by Riverstone, is the current plant operator. Talen owns 50 percent of Colstrip Units 1 and 2, and 30 percent of Unit 3 (15 percent in a reciprocal sharing agreement across Units 3 and 4) and acts as the current

---

[41] Talen Energy, Colstrip Power Plant, https://www.talenenergy.com/generation/fossil-fuels/colstrip (last visited Jun. 28, 2017) (emphasis added).

operator of the facility. Unlike the other co-owners of the Colstrip units which are all public utilities, Talen is a merchant generator. As such, Talen has expressed concerns about the continued operation of Units 1 and 2, as well as indicating that it wishes to discontinue its role as plant operator.

PSE owns the other 50 percent of Colstrip Units 1 and 2. The current ownership interests of Colstrip Units 3 and 4 are as follows:[42]

Colstrip Units 3 and 4		
Current Owership Interests		
Owner	**Units 3 and 4**	**Total MW**
Puget	25%	370
PGE	20%	296
Talen	15%	222
Northwestern	15%	222
Avista	15%	222
PacifiCorp	10%	148
TOTALS	**100%**	**1480**

Q: What concerns have been raised regarding the continued operation of the Colstrip plant?

A: As described in PSE's "Colstrip Strategic Planning Update" dated March 2, 2017 (*see* Exhibit RCS-11C), Talen has reported that Units 1 and 2 are losing money. On May 23, 2016, Talen provided a two-year notice of resignation as operator of

[42] *See*, e.g., PSE's "Colstrip Strategic Planning Update" dated March 2, 2017, at page 4. This document is reproduced for ease of reference as Exhibit RCS-11C. While this document has been designated as CONFIDENTIAL, the ownership percentages are public information.

Units 3 and 4.[43] This raised concerns about the remaining service life of Units 1 and 2, as well as the continued operation of Units 3 and 4.

Q: What service life has PSE projected for Colstrip Units 1 and 2?

A: PSE has reflected a retirement date Colstrip Units 1 and 2 of July 1, 2022.

Q: What is the basis for that retirement date?

A: As explained in the testimony of PSE witness Ronald Roberts, at page 39, line 5-6, and in PSE's response to Public Counsel Data Request No. 395,[44] PSE intends to keep Colstrip Units 1 and 2 in operation until the legal settlement date of on or before July 1, 2022. That date is based on a legal settlement which specifies a retirement date of Colstrip Units 1 and 2 in operation until the legal settlement date of on or before July 1, 2022. PSE witness Ronald Roberts discusses the decision to settle litigation and retire Colstrip Units 1 and 2 at pages 34-39 of his Prefiled Direct Testimony.

---

[43] *See*, e.g., Carly Garrison, *Colstrip Power Plant Closure Could Come Earlier than 2022*, KTVH, http://www.ktvh.com/2017/01/colstrip-power-plant-closure-could-come-earlier-than-2022 (Jan. 18, 2017); *see also*, e.g., Tom Lutey, *Colstrip Operator Wants Out in 2 Years or Less*, *The Missoulian*, http://missoulian.com/news/state-and-regional/colstrip-operator-wants-out-in-years-or-less/article_d0aae700-4348-5007-9bf3-1ed9758de6f8.html (May 25, 2016); and Krysti Shallenberger, Talen Energy Will Cease Operating Embattled Colstrip Cola Plant in 2018, Utility Dive, http://www.utilitydive.com/news/talen-energy-will-cease-operating-embattled-colstrip-coal-plant-in-2018/419895/ (May 26, 2016). See also, PSE's response and first supplemental responses to Sierra Club Data Request No. 4, which are reproduced in Exhibit RCS-10C. Notably, PSE's first supplemental response to Sierra Club Data Request No. 4 included a copy of a notice from Talen dated June 19, 2017, to the co-owners of Colstrip Units 3 and 4 withdrawing Talen's Resignation as Operator. Moreover, that response states that: "Talen Montana has no intention of resigning as the operator of Units 1 and 2, resulting in inefficiencies because of separate operators for Units 1 and 2 and Units 3 and 4." The response presents several reasons that were stated by Talen for continuing to function as the operator of the Colstrip plant.

[44] Exh. No. RCS-10C.

Q: Is it possible that that Colstrip Units 1 and 2 could be retired prior to July 1, 2022?

A: Yes. As stated by PSE witness Ronald Roberts at pages 39-41 of his Prefiled Direct Testimony, PSE plans for the operation of Colstrip Units 1 and 2 until July 1, 2022. However, forces not under PSE's control may cause the retirement of Colstrip Units 1 and 2 prior to July 1, 2022.

Q: If Talen Energy exits its role as operator of the Colstrip Plant, how would that affect the operation and projected retirement of <u>Colstrip Units 1 and 2</u>?

A: Public Counsel asked this question of PSE Public Counsel Data Request No. 395(a).[45] PSE's response states that:

> a) PSE does not currently foresee significant changes in the operation of Colstrip Units 1 and 2 under a potential new operator. However, the joint Colstrip owners are currently in the due diligence phase of identifying a potential new operator; therefore, additional information that affects this question may be identified. PSE does not envision an operator change effecting the date of retirement for Colstrip Units 1 and 2.[46]

Q: If Talen Energy exits its role as operator of the Colstrip Plant, how would that affect the operation and projected retirement of <u>Colstrip Units 3 and 4</u>?

A: Public Counsel asked this question of PSE in Public Counsel Data Request No. 395(b).[47] PSE's response states that:

> b) PSE does not currently foresee significant changes in the operation of Colstrip Units 3 and 4 under a potential new operator.

[45] Exh. RCS-10C.
[46] Exh. RCS-10C.
[47] Exh. RCS-10C.

> However the joint Colstrip owners are currently in the due diligence phase of identifying a potential new operator; therefore, additional information that affects this question may be identified. There is no projected retirement date agreement between the owners of Colstrip Units 3 and 4.[48]

Q: Has recent information indicated that Talen will continue as operator of the Colstrip plant?

A: Yes. PSE's supplemental response to Sierra Club Data Request No. 4, for example, includes a letter from Talen to the co-owners dated June 18, 2017, which indicates that Talen has withdrawn the previous notice of resigning as operator of Colstrip (dated May 23, 2016) and states further that Talen will continue to operate the Colstrip plant.[49] Talen's letter presents several reasons for its decision to continue as operator of the Colstrip plant.

Q: Does Talen's June 19, 2017, letter indicate that Talen Montana will reimburse the other owners for their reasonable out-of-pocket costs incurred to date related to the effort to transition to a new operator?

A: Yes. Talen's June 19, 2017, letter on page 2 states that:

> Additionally, as a gesture of good faith and to remedy the financial impacts resulting from the notice of intent to resign, Talen Montana is prepared to reimburse the other owners for their reasonable out-of-pocket costs incurred to date related to the effort to transition to a new operator, including the fees paid to the Owners' joint legal counsel, up to $225,000 in the aggregate.

Q: Do you have a recommendation relating to this commitment by Talen

---

[48] Exh. RCS-10C.

[49] Exhibit RCS-10C includes a copy of PSE's response and first supplemental response to Sierra Club Data Request No. 4, including the Talen letter dated June 18, 2017, that was attached to that response.

Montana?

A: Yes. I recommend that PSE compile and report all of its out-of-pocket costs related to efforts to transition to a new operator of the Colstrip plant. I recommend that the Commission instruct PSE to remove such costs from the revenue requirement in the current rate case, and to collect such costs from Talen Montana, and not from PSE's ratepayers.

Q: You mentioned that there is a projected retirement date for Colstrip Units 1 and 2 of on or before July 1, 2022 that is based on a legal settlement. Is there a projected retirement date agreement between the owners for Colstrip Units 3 and 4?

A: No, according to PSE's response to Public Counsel Data Response No. 395(c)(i) which states that: "There is no projected retirement date agreement between the owners of Colstrip Units 3 and 4."[50]

Q: What has PSE reflected in its general rate case for the assumed retirement dates for the Colstrip units?

A: As described in the Prefiled Direct Testimony of PSE witness Ronald Roberts at page 48, Colstrip Units 1 and 2 now have a planned retirement date of July 1, 2022. Colstrip Units 3 and 4 do not have any planned date for retirement. For determining depreciation rates and for purposes of analyzing

[50]Exh. RCS-10C.

decommissioning and demolition costs, PSE assumed that Colstrip Units 3 and 4 would be retired in 2035.

Q: Has the ownership of Talen changed in December 2016?

A: Yes. In December 2016, Talen was acquired by Riverstone Holdings, LLC ("Riverstone") for $1.8 billion. As described in PSE's response to WUTC Staff Data Request No. 461:[51]

> Riverstone has replaced the executive team and officers at Talen ... and begun their due diligence on the assets they acquired in December from Talen. ... [A]s Riverstone has learned more about Colstrip operations and financials, they are reevaluating the statements made by former management (Mr. McGuire) [redacted].

Q: Has PSE indicated that anticipatory steps have been taken by the non-Talen owners of Colstrip?

A: Yes. PSE's "Colstrip Strategic Planning Update" dated March 2, 2017 (*see* Exhibit RCS-11C), indicates at page 3 that [redacted]:

- [redacted]
- [redacted]
- [redacted]

Page 4 of that document indicates further that [redacted]

[51] Exh. RSC-10C.

[redacted].

B. Costs Requested by PSE Related to Colstrip

Q: What are some of the types of costs have been requested by PSE in its general rate case related to Colstrip?

A: PSE's general rate case reflects Colstrip costs, including the following:

- Costs for Plant net of Accumulated Depreciation
- Depreciation Expense
- Costs for Decommissioning and Demolition
- Costs for Coal Combustion Residuals ("CCRs")
- Operating and Maintenance Expense

C. Colstrip Plant and Accumulated Depreciation

Q: How have you reflected Colstrip Plant and Accumulated Depreciation?

A: I have reflected PSE's proposed amounts for Colstrip Plant. I have reflected an adjustment for electric utility Accumulated Depreciation to reflect the impact of the recommended new depreciation rates sponsored by Public Counsel witness Ms. McCullar, as discussed above. Beyond that, there is no other adjustment for Colstrip Accumulated Depreciation.

D. Costs for Decommissioning and Demolition

Q: What costs for decommissioning and demolition of Colstrip Units 1 and 2 have PSE requested?

A: The Prefiled Direct Testimony of PSE witness Daniel Doyle addresses this, starting at page 41. At pages 42-43 he states that:

> As explained in the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. KJB-1T, decommissioning and remediation costs of Colstrip Units 1 & 2 have not been recovered from customers in any material amount during the 40+ year period those units operated because there was no legal obligation to undertake remediation, the costs for decommissioning and remediation were not known and measurable, and these costs were not included in depreciation rates.
>
> This proceeding is the appropriate venue for considering, reviewing and adjudicating the complex array of issues connected with the imminent retirement of the boilers of Colstrip Units 1 & 2 for the following reasons:
>
> (i) PSE has projected anticipated decommissioning and remediation costs of approximately $109 million (in real dollars) for Colstrip Units 1 & 2 (see the Prefiled Direct Testimony of Mr. Ron Roberts, Exhibit No. ___(RR-1CT), for details of these projected costs);
>
> (ii) the settlement agreement with the Sierra Club and Montana Environmental Information Center requires that the boilers of Colstrip Units 1 & 2 be retired no later than July 1, 2022, which leaves limited time for planning, financing, and regulatory review of all aspects of decommissioning and remediating activities;
>
> (iii) PSE was successful in obtaining legislation in early 2016 that allows for the repurposing of certain regulatory liabilities (i.e., Treasury Grants and wind-related Production Tax Credits) to offset decommissioning and remediation costs for Colstrip

Units 1 & 2 (see Chapter 80.84 RCW (Transition of Eligible Coal Units)); and

(iv) RCW 80.84.020 requires an adjudicative proceeding under chapters 34.05 and 80.04 RCW prior to the authorization of PSE to place amounts from one or more regulatory liabilities into a retirement account to cover decommissioning and remediation costs of eligible coal units.

Q: The last item refers to a request by PSE for authorization to place amounts from one or more regulatory liabilities into a retirement account to cover decommissioning and remediation costs of eligible coal units. How is PSE proposing to apply that to Colstrip Units 1 and 2 decommissioning and demolition costs in the current general rate case?

A: As described at page of Mr. Doyle's Prefiled Direct Testimony, PSE proposes to "repurpose" certain regulatory liabilities (i.e., Treasury Grants and wind-related Production Tax Credits) into a recovery mechanism for Colstrip Units 1 & 2 decommissioning and remediation costs. Under this proposal, PSE would "repurpose" these regulatory liabilities to offset and fund Colstrip Units 1 & 2 decommissioning and remediation costs rather than pass back these tax benefits to customers in the form of lower current rates than would be provided prior to having to incur the decommissioning and remediation costs.

Q: Is such a "repurposing" proposal permitted by legislation that was passed in Washington?

A: Yes. In the 2016 legislative session, a bill was enacted[52] that provides for the repurposing of tax benefits to recover Colstrip Units 1 & 2 decommissioning and remediation costs.

Q: How does PSE propose to apply the "repurposed" regulatory liabilities toward the recovery of Colstrip Units 1 & 2 decommissioning and remediation costs?

A: As explained in the Prefiled Direct Testimony of PSE witness Ms. Barnard on page 31, and in PSE's response to Public Counsel Data Request No. 355, PSE proposes to discontinue amortization of a regulatory liability that PSE had recorded for Treasury Grants that PSE received for the upgrades to its hydroelectric facilities. PSE proposes to transfer the unamortized balance related to that regulatory liability into a FERC 108 retirement account[53] that would be established to help fund the decommissioning and remediation costs associated with Colstrip Units 1 and 2. As explained in PSE's response to Public Counsel Data Request No. 355(c),[54] the amounts reflected in PSE Adjustment 7.12 represent PSE's calculation of the hydro grants net balance for the Company's proposed transfer.

---

[52] *See*, e.g., Chapter 80.84 RCW (Transition of Eligible Coal Units).
[53] FERC account 108 is also commonly referred to as Accumulated Depreciation.

[54] Exh. No. RCS-10C.

Q: What reasons does PSE give for applying the "repurposed" regulatory liabilities towards the cost recovery of Colstrip Units 1 & 2 decommissioning and remediation costs?

A: As explained by PSE witness Mr. Doyle at page 46 of his Prefiled Direct Testimony:

- By applying the "repurposed" regulatory liabilities toward the recovery of Colstrip Units 1 & 2 decommissioning and remediation costs, PSE avoids charging current and future ratepayers for those costs.
- PSE will continue to treat these regulatory liabilities as reductions to rate base (and thereby benefitting customers) until the tax benefits are fully utilized to offset Colstrip Units 1 & 2 decommissioning and remediation costs.
- PSE also states that this treatment eliminates the need for recovery of carrying costs associated with regulatory assets that would likely be established to recover these costs under traditional ratemaking methodologies.

Q: Does PSE claim that its proposed treatment results in a net savings to ratepayers?

A: Yes. PSE witness Mr. Doyle asserts at page 46 of his Prefiled Direct Testimony that the Company's proposed treatment will save customers approximately $71.2 million in nominal terms and $49.5 million on a net present value basis versus collecting those costs through a new tracker mechanism.

Q: Do you have a recommendation related to assuring that PSE's ratepayers realize these savings?

A: Yes. PSE's Colstrip related decommissioning and remediation costs should continue to be monitored to assure that ratepayers realize these savings and specifically to assure that these ratepayer savings are not negated by additional higher Colstrip decommission and remediation costs, beyond those currently reflected by PSE in its calculations.

Q: Are you proposing any adjustments for a different application of the regulatory liability for income tax benefits that PSE proposes to apply to recover Colstrip Units 1 & 2 decommissioning and remediation costs?

A: No. PSE's proposal appears to be consistent with the authorizing legislation. The regulatory liabilities for Treasury Grants for hydroelectric facility upgrades (and the Production Tax Credit tax benefits) that PSE proposes to apply to recover Colstrip Units 1 & 2 decommissioning and remediation costs are not otherwise related to Colstrip. Nevertheless, PSE's proposal appears to be consistent with the authorizing legislation noted above and reasonable in the context of the current general rate case.

Q: Will the actual decommissioning and remediation costs need to be reviewed?

A: Yes. Even though there is not a challenge to these funding mechanisms, this should not be construed as granting preapproval of the activities or the costs that are to be used to fund these activities. In other words, the Colstrip owners, including PSE, have not performed the specific decommissioning and remediation activities yet, so actual cost recovery must still be based on those activities happening and the related costs being reviewed and being reasonable and prudent.

The review of actual Colstrip decommissioning and remediation costs for prudence and reasonableness should, therefore, continue to be an issue in future PSE rate cases, through and including when those activities are completed.

E. PSE's Proposed Use of Production Tax Credits to Recover Colstrip Units 1 and 2 Costs

Q: What does PSE propose for the potential use of Production Tax Credits ("PTCs")?

A: PSE witness Mr. Doyle at page 47 of his Prefiled Direct Testimony states that:

> Regulatory liabilities for Production Tax Credits could similarly be repurposed to recover decommissioning and remediation costs. To date, PSE has generated approximately $200 million of Production Tax Credits. Those Production Tax Credits are currently reflected on PSE's balance sheet as a regulatory liability along with the associated deferred tax treatment. Although these Production Tax Credits have been generated, PSE has not yet had the opportunity to use the credits on tax returns. Therefore, the Production Tax Credits have not yet been "funded" in cash through reduced current taxes payable.

Q: How does PSE propose to apply the PTCs once they are "funded" through reduced income taxes payable?

A: PSE witness Mr. Doyle at pages 47-48 of his Prefiled Direct Testimony states that:

> As the Production Tax Credits are utilized on tax returns and become funded in cash through reduced current taxes payable, the

> funded portion of the regulatory liability will be reclassified to the new FERC 108 account established for Colstrip Units 1 & 2, at which time it will become a reduction to PSE's rate base. Please see the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for additional details.

Q: When does PSE project that "funding" of the PTCs would occur?

A: PSE projects that "funding" of the PTCs would occur in 2019 and beyond as the ability to claim bonus tax depreciation is phased out.[55] PSE witness Mr. Doyle states that PSE anticipates that "PSE expects the utilization of Production Tax Credits to accelerate into 2019 and beyond" and "[b]ased on current tax law, it is highly probable that all of PSE's generated Production Tax Credits will be utilized by 2020." However, he qualifies this by pointing out that prediction of utilizing Production Tax Credits over the next few years is uncertain.[56]

Q: What would happen if the combined total of repurposed Treasury Grants and Production Tax Credits were to exceed Colstrip Units 1 & 2 decommissioning and remediation costs?

A: As explained by PSE witness Mr. Doyle, if the combined total of repurposed Treasury Grants and PTCs were to exceed Colstrip Units 1 & 2 decommissioning and remediation costs, any remaining funds in the retirement account would be returned to customers.[57] Returning any such excess amounts to ratepayers appears to be required by RCW 80.84.020(2)(c).

---

[55] *See*, e.g., Prefiled Direct Testimony of Daniel A. Doyle, Exh. DAD-1T at 48-49.
[56] *Id.*
[57] *Id.*, at 49.

F. Costs for Colstrip Coal Combustion Residuals ("CCRs")

Q: What are Coal Combustion Residuals costs?

A: Coal Combustion Residuals ("CCRs") costs are costs related to cleaning up ash ponds and landfills into which coal ash and other residuals associated with coal-fired generation have been stored. The costs that PSE and the other Colstrip owners will likely eventually have to spend relating to ash pond closures and remediation are related to issues contained in the United States Environmental Protection Agency's ("EPA") Coal Combustion Residuals ("CCR") Rule which was published on April 17, 2015. The CCR rules were published by the EPA in 2015 and the costs that PSE (and the other Colstrip owners) will incur for the ash ponds will be pursuant to those rules.

Q: What costs for Colstrip CCRs has PSE requested?

A: As shown on PSE Exhibit RJR-23, PSE projects total CCR costs of $149.988 million in 2016 dollars and $205.846 million in real dollars for the period 2016 through 2051, of which PSE's share is $74.994 million and $102.923 million, respectively.

Q: Has PSE indicated whether the amounts of CCR costs in its Exhibit RJR-23 are for Colstrip Units 1 and 2?

A: Yes. In response to Public Counsel Data Request 420(f),[58] PSE indicated that the CCR plan costs listed on page 2 of Exhibit RJR-23 are for PSE's share of the CCR amounts for Colstrip Units 1 and 2.

Q: Has PSE presented another exhibit for CCR costs for Colstrip Units 3 and 4?

A: Yes. PSE's response to Public Counsel Data Request 420(f), PSE indicated that the CCR plan costs for Colstrip Units 3 and 4 are included in Exhibit RJR-24 but have not been summarized in the same fashion as Colstrip Units 1 and 2 costs were on PSE's Exhibit RJR-23.

Q: Has PSE recorded Asset Retirement Obligations ("AROs") for Colstrip Units 1 and 2 decommissioning and dismantlement costs?

A: According to PSE's response to Public Counsel Data Request 420(c) PSE has not recorded AROs for Colstrip Units 1 and 2 decommissioning and dismantlement costs. Moreover, according to PSE's response to WUTC Staff Data Request 142,

> there is not a detailed list of activities or projects associated with the Colstrip Units 1 & 2 non-legal (Non-Asset Retirement Obligation) cost of removal portion of the accumulated depreciation reserve balance. The non-legal portion of cost of removal associated with Colstrip Units 1 & 2, as of September 30, 2016, is $8,836,193.

PSE included with that response a listing of the amounts through September 30, 2016 by year.[59]

---

[58] Exh. No. RCS-10C.
[59] These responses are included in Exhibit RCS-10C.

Q: How has PSE treated the CCR costs in its general rate case application?

A: PSE has treated the CCR costs estimated for Colstrip Units 1 and 2 as being funded by the repurposing of the treasury grants for the hydroelectric facilities and by applying tax benefits expected to be realized from Production Tax Credits.[60]

Q: Are you recommending an adjustment for the Colstrip CCR costs?

A: No. I am not recommending a specific adjustment for Colstrip Units 1 and 2 CCR costs. I note that Public Counsel witness Ms. McCullar has incorporated the cost of removal amount she recommends for Colstrip Units 3 and 4 into her recommended depreciation rates, which I have reflected in determining PSE revenue requirements.

G. Operating and Maintenance Expense

Q: What O&M Expense for Colstrip has PSE requested?

A: As explained in the Prefiled Direct Testimony of PSE witness Ronald Roberts at pages 58-59, PSE has requested amortization, based on a 36-month amortization period, of the following Colstrip overhaul costs, which are listed in his Table 3 and his Exhibit RJR-26C (shaded amounts are CONFIDENTIAL):

/ /

/ / /

[60] *See*, e.g., PSE's responses to Public Counsel's Data Request Nos. 420(a) and 426(g) and PSE's response to WUTC Staff's Data Request Nos. 296 and 359. These responses are included in Exhibit RCS-10C.

Colstrip Overhaul Expense Proposed by Company

Plant	Event*	Event Date	Amt to Amort	Amort Period	Monthly Amort **	Amort Begin	Amort End	Rate Year
Colstrip 1/2	Colstrip Unit #1 Outage	5/6/16	[redacted]	36	[redacted]	6/1/16	5/31/19	[redacted]
Colstrip 1/2	Colstrip Unit #1 Outage (a)	4/30/17	[redacted]	36	[redacted]	5/1/17	4/30/20	[redacted]
Colstrip 1/2	Colstrip Unit #2 Outage	6/30/15	[redacted]	36	[redacted]	7/1/15	6/30/18	[redacted]
Colstrip 1/2	Colstrip Unit #2 Outage	6/30/18	[redacted]	36	[redacted]	7/1/18	6/30/21	[redacted]
Colstrip 3/4	Colstrip Unit #3 Outage	6/30/14	[redacted]	36	[redacted]	7/1/14	6/30/17	[redacted]
Colstrip 3/4	Colstrip Unit #3 Outage	6/30/17	[redacted]	36	[redacted]	7/1/17	6/30/20	[redacted]
Colstrip 3/4	Colstrip Unit #4 Outage	6/30/16	[redacted]	36	[redacted]	7/1/16	6/30/19	[redacted]
	TOTALS				[redacted]			[redacted]

* - Note: major maintenance work performed concurrently that have materially different OEM recommended maintenance intervals have been split into separate events with the same completion date (ex: Gld Steam Major and Summary Inspections).

**- Note: monthly amortization rates may differ from amount calculated by dividing event cost by amortization period. This is due to late charges or adjustmentsthat may be booked after the beginning of the amortization period. In such cases, the revised monthly rate is recalculated based on the remaining unamortized balance , including such late charges or adjustments, divided by the remaining amortization period. The monthly amortization rates included in the schedule above reflect the most current monthly rate available. (a) - Due to uncertainties in 2016 associated with pending NSR (new source review) litigation, the scope of the 2016 major maintenance e event was reduced and a portion of the work was deferred into 2017.

(a) - Due to uncertainties in 2016 associated with pending NSR (new source review) litigation, the scope of the 2016 major maintenance e event was reduced and a portion of the work was deferred into 2017

The overhaul expense requested by PSE for Colstrip is approximately [redacted].

In addition, PSE has included non-overhaul Colstrip O&M expense for the rate year of $39.1 million based on the operator budget. This compares with $35.8 million for the 2014 PCORC rate year and $36.1 million in the test year.

PSE includes the costs for the Colstrip major overhaul expense in its AURORA model runs which PSE uses to determine its requested rate year power costs.

Q: Are you recommending any adjustments for the Colstrip major overhaul or non-overhaul O&M expenses at this time?

A: No, not at this time, based on the information provided by PSE that Colstrip Units 1 and 2 are currently projected to operate through July 1, 2022. If during the course of this proceeding it becomes apparent that Colstrip Units 1 and 2 will be retired prior to July 1, 2022, there may be a need to eliminate or scale back the projected expenses that been used by PSE for a Colstrip Unit 2 overhaul outage for June 2018 of [redacted].

Q: Does that conclude your testimony?

A: Yes, it does.