EXH. SEF-1T
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: SUSAN E. FREE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-22____** **Docket UG-22____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

SUSAN E. FREE

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

PUGET SOUND ENERGY

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PUGET SOUND ENERGY

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I. INTRODUCTION

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

A. My name is Susan E. Free, and my business address is Puget Sound Energy, P.O. Box 97034, Bellevue, Washington 98009-9734. I am employed by Puget Sound Energy ("PSE" or the "Company") as Director of Revenue Requirements and Regulatory Compliance.

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

A. Yes, I have. It is Exhibit SEF-2.

Q. What are your duties as Director of Regulatory Requirements and Regulatory Compliance for PSE?

A. As Director of Revenue Requirements and Regulatory Compliance, I am responsible for strategy, policy, direction, and coordination of PSE's interests on state regulatory issues. I oversee state regulatory processes and compliance requirements, including, audits, rate cases and regulatory proceedings. I represent PSE in regulatory issues with state regulators and other constituents. I negotiate rate and tariff issues with customers, agencies, stakeholders and regulators. I am the primary accounting witness for PSE on regulatory matters.

Q. What topics are you covering in your testimony?

A. My testimony and exhibits in this proceeding will address the revenue requirement calculations in the context of the multiyear rate plan that are requested in this proceeding as required by statute.[1] I also discuss how the Commission's policy statement ("Used and Useful Policy Statement" or "policy statement")[2] will work in concert with the new legislation. I demonstrate that PSE's current rates are insufficient for its current operations, which has created the need for this filing. I present the calculation of the revenue requirement and the associated requested net revenue change for electric and natural gas operations for each of the rate years being proposed in PSE's multiyear rate plan. I present the proposals for rates subject to refund and the review process for property that will become used and useful after the initial setting of rates as required by the Commission's policy statement. I present a proposal for the recovery of Colstrip decommissioning and remediation ("D&R") costs as required by the Commission in PSE's 2019 general rate case.[3] Finally, I provide updated baseline rates for use in PSE's Power Cost Adjustment ("PCA") mechanism for each of the rate years.

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[1] RCW 80.28.425(1).

[2] *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531 (Jan. 30, 2020).

[3] *WUTC v. PSE*, Dockets UE-190529/UG-190530, Order 08, ¶¶ 425, 767 (July 8, 2020).

II. MULTIYEAR RATE PLAN

A. RCW 80.28.425 Multiyear Rate Plans

Q. What does RCW 80.28.425 ("MYRP Statute") mandate concerning multiyear rate plans?

A. The MYRP Statute requires that every general rate case filing include a proposal for a multiyear rate plan beginning January 1, 2022. The duration of the multiyear rate plan must be between two and four years in length.

Q. Is PSE proposing a multiyear rate plan in this filing?

A. Yes. PSE is proposing a three-year multiyear rate plan.

Q. Please provide a high-level overview of how PSE's proposed multiyear rate plan is constructed.

A. Mr. Jon A. Piliaris provides a comprehensive overview of PSE's proposed multiyear rate plan in his Prefiled Direct Testimony, Exh. JAP-1T. I discuss the portions of the multiyear rate plan proposal that relate to revenue requirement. PSE's proposed multiyear rate plan includes the development of the historical test year, the initial rate year (calendar year 2023), the second rate year (calendar year 2024), and the third rate year (calendar year 2025). PSE's test year is the twelve months ended June 30, 2021, and PSE is requesting that rates become effective for the first rate year on January 1, 2023. The MYRP Statute requires that, if the multiyear rate plan is approved, the Commission must approve rates for each of the rate years.[4]

As discussed in more detail below, the filing starts with restated results for the twelve months ended June 30, 2021 as required by WAC 480-07-510(3)(c)(i). This presentation of the restated test year results demonstrates that rates are insufficient. Following the restated results, the filing presents adjustments for the traditional pro forma period through December 2021, and provisional pro forma adjustments to reflect the value of plant for rate making purposes at the start of rate year, December 31, 2022 as required by the MYRP statute.[5] Finally, the filing presents pro forma and provisional pro forma adjustments for each of the three rate years from 2023 through 2025.

Q. For purposes of satisfying the requirement in RCW 80.28.425(3)(b), how is PSE valuing its property that is in service as of December 31, 2022?

A. Consistent with long-held Commission practice, PSE is valuing property that is in service at the first rate effective period at its recorded or estimated net book value. In addition to being consistent with past practice, using net book value as the measure by which to value utility property for ratemaking purposes provides a representative, auditable value. Recorded net book value can be substantiated by accounting records such as invoices and checks that have been subject to the

[4] RCW 80.28.425(3)(a).

[5] RCW 80.28.425(3)(b) states that "[f]or the initial rate year, the commission shall, at a minimum, ascertain and determine the fair value for rate-making purposes of the property of any gas or electrical company that is used and useful for service in this state as of the rate effective date."

review and audit of PSE's external auditors and can be easily verified by parties in a regulatory proceeding. Additionally, corporate budgeting processes, including those used by Washington regulated utilities, are designed to estimate the book cost of the investments that are being forecast.

Q. Please elaborate on the timing of plant that is included in rates.

A. The time period for plant to be included in rates should be as of the start of the first rate effective period as is clearly required by RCW 80.28.425(3)(b). The intent of this section of the statute is to address regulatory lag, an important component of the legislation, which allowed Washington's regulated utilities to support the legislation. Using an earlier date of valuation as a proxy for the rate-effective date valuation would not be upholding the intent of this section of the statute.

Q. Are there safeguards in place so that customers will only pay for plant that is actually put in service?

A. Yes. The Commission's policy statement provides for provisional pro forma adjustments that are subject to refund if the projected plant does not go into service. Additionally, RCW 80.28.425(3)(b) provides that the Commission may order refunds to customers if property expected to be used and useful by the rate effective date is in fact not used and useful by such date. These safeguards provide assurance to the Commission and customers that customers will only pay for plant that goes into service and is prudently incurred.

Q. Please summarize the timing for valuation of property for the entirety of the multiyear rate plan that PSE is proposing.

A. For initial rates that go into effect at the start of the first rate year, January 1, 2023, PSE is providing actual data through June 30, 2021 with pro forma adjustments through the traditional pro forma period through December 31, 2021, which has been updated with actual data through September 30, 2021 where appropriate. In addition, initial rates will include forecasted plant additions and retirements through December 31, 2022, which will be subject to refund if representative plant does not actually go into service or more plant is retired than originally projected. The proposed initial rates also include forecasted plant additions for 2023 with the resulting rate base reflected on an average of the monthly averages ("AMA") basis.

Plant additions and retirements for 2023 through 2025 will be based on the Company's forecasts. The overall corporate forecast for plant additions is presented by PSE witness Joshua A. Kensok, and specific forecasted amounts used for the provisional pro forma adjustments are supported by various subject matter expert witnesses in the filing.

Q. Is the Company proposing to update estimated values to actual values during the proceeding?

A. Potentially. As stated above, certain of PSE's pro forma adjustments are based on actuals through September 30, 2021. PSE does not plan to request wholesale updates to these amounts during the course of the proceeding. However, if significant changes to forecasting assumptions on such things as PSE's filed Clean Energy Implementation Plan or on any specific provisional pro forma adjustments such as Energize Eastside occur, PSE would request to include these updates in the proceeding. Assuming parties' response testimonies are due in mid-June, a supplemental filing could be made in mid-April to incorporate these types of updates as well as updates to power costs as discussed in the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-1CT.

Q. How does PSE plan to reflect power costs in the multiyear rate plan?

A. The power costs in the initial rate year are developed using a rate year forecast in the same manner they have been determined in prior proceedings. Mr. Wetherbee provides support for the power costs for the initial rate year. He also supports power costs for the second and third rate years in 2024 and 2025, but only with respect to existing resources and contracts that have been executed as of the filing of this proceeding.

In addition, PSE is proposing to modify its PCA mechanism so that the variable portion of the PCA baseline rate would be updated in rates annually. This proposal is included in the Prefiled Direct Testimony of Janet K. Phelps, Exh. JKP-1T.

Q. Why is PSE proposing to update rates for the variable portion of the PCA baseline rate each year?

A. The costs that Mr. Wetherbee has presented in this proceeding for the second and third rate year are not reflective of the costs and resources anticipated to meet reliability and renewable energy requirements necessary to meet the Clean Energy Transformation Act ("CETA").[6] As Ms. Phelps discusses in her testimony, PSE's requested annual power cost update would better position PSE to meet its clean electricity requirements under CETA by providing recovery of the costs associated with transitioning to clean electricity.

Q. What other changes is PSE proposing regarding its PCA mechanism?

A. Also supported by Ms. Phelps is PSE's proposal to retain the ability to file power cost only rate cases ("PCORC") as part of its PCA mechanism. Ms. Phelps proposes that, in concert with the ability to update its variable power costs annually, PSE be allowed to continue to have the ability to file PCORCs but only for fixed production costs on an as needed basis.

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[6] RCW 19.405 Washington Clean Energy Transformation Act.

Q. If the Commission approves PSE's proposal to allow the continued use of PCORCs for recovery of fixed production costs, would you recommend any additional modifications for this proceeding?

A. Yes. With the ability to use PCORCs to bring in fixed production costs, there would no longer be the need to include estimated fixed production plant closings and operating expenses in the revenue requirement for 2024 and 2025. The below table provides an estimate of the change in the revenue requirement that would occur if fixed production costs for 2024 and 2025 are removed from PSE's request. Due to changes in load between periods, the removal of these costs results in both a decrease and an increase to the requested deficiencies.

Table 1. Impact on Deficiencies for Removing 2024 and 2025 Fixed Production Costs

Line	Description		2024		2025	Exh. SEF-12 Reference
1	Total Fixed Cost Prior Year	$	410,760,431	$	406,854,427	Page 1 and 2 Line 29 Column (IV)
2	Load Prior Year		19,671,400		19,868,188	Page 1 and 2 Line 30 Column (II)
3	Prior Year Baseline Rate	$	20.881	$	20.478	Page 1 and 2 Line 36 Column (II)
4						
5	Total Cost Current Year	$	406,854,427	$	404,370,570	Page 2 and 3 Line 29 Column (IV)
6	Load Current Year		19,868,188		19,443,871	Page 2 and 3 Line 30 Column (II)
7	Current Year Baseline Rate	$	20.478	$	20.797	Page 2 and 3 Line 36 Column (II)
8						
9	BLR Change	$	(0.40)	$	0.32	Line 7 - Line 3
10	Volumetric Change	$	(8,015,153)	$	6,205,171	Line 9 x Line 6
11	Whole Dollar Change	$	(3,906,004)	$	(2,483,857)	Line 5 - Line 1

Q. Is PSE's proposal for updating power costs consistent with the MYRP Statute?

A. Yes, I believe it is. RCW 80.28.425(3)(e) requires that when the Commission approves a multiyear rate plan with a duration of three or four years, the company must update its power costs as of the rate effective date of the third rate year, but it does not require or prohibit other updates to power costs. PSE will be updating its power costs for the third rate year as required by the statute, but as proposed, PSE will also be updating its power costs as of the second rate year.

Q. Does the MYRP Statute contain an earnings test?

A. Yes. The statute states the following:

> If the annual commission basis report for a gas or electrical company demonstrates that the reported rate of return on rate base of the company for the 12-month period ending as of the end of the period for which the annual commission basis report is filed is more than .5 percent higher than the rate of return authorized by the commission in the multiyear rate plan for such a company, the company shall defer all revenues that are in excess of .5 percent higher than the rate of return authorized by the commission for refunds to customers or another determination by the commission in a subsequent adjudicative proceeding.[7]

Q. How will this apply to PSE?

A. This mechanism should replace PSE's current earnings sharing mechanism to reduce administrative burden and prevent confusing and conflicting results and

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[7] RCW 80.28.425(6).

allow the Company to have only one earnings test in place. The Commission will determine the appropriate disposition of any approved imbalance, including the appropriate period over which an imbalance is credited to customers if determined necessary.

Q. Do you have any other observations about the earnings test mechanism required by the MYRP Statute?

A. Yes. First, the earnings test required by statute provides for a band above a utility's authorized rate of return prior to requiring a deferral of over-earnings. PSE's existing earnings sharing mechanism does not have such a band. Although the addition of the band is more lenient than PSE's existing mechanism, there is another important difference which provides an offset for the addition of the band in the statutory mechanism. PSE's current mechanism is based on modified actuals rather than on a normalized Commission basis.[8] Therefore, PSE will lose this important consideration under the statutory mechanism. As such, the statutory mechanism provides for a balanced alternative to PSE's existing earnings sharing mechanism and should be the only mechanism required.

Additionally, there will be important considerations that must be made in administering the statutory earnings mechanism when rates are subject to refund. These considerations are important in order to prevent duplication of refunds under both the statutory mechanism and the annual review process that will

[8] *WUTC v. Puget Sound Energy*, Dockets UG-170033/UE-170034, Order 08 ¶¶ 313 & 426 (Dec. 5, 2017).

determine if rates under the multiyear rate plan will be refunded. To prevent the duplication of refunds, any amount determined to be refundable under the annual multiyear rate plan review process must reduce the deferral amount booked under the statutory earnings mechanism.

B. Used and Useful Policy Statement

Q. Please explain the regulatory ratemaking standard of used and useful.

A. The used and useful standard is a ratemaking concept that relates to the valuation of the rate base upon which a return will be granted. Conceptually, it provides that the rate base should be based only on those assets that are used to provide the regulated service, and that are useful in the provision of that service.

Q. Has the used and useful standard been defined by the Commission?

A. Yes. As discussed above, the Commission issued the Used and Useful Policy Statement to establish a process to identify, review, and approve public service company property that becomes used and useful after the rate effective date. RCW 80.04.250 for which the policy statement was issued, states the following:

> the valuation may include consideration of any property of the public service company acquired or constructed by or during the rate effective period, including the reasonable costs of construction work in progress, to the extent that the commission finds that such an inclusion is in the public interest and will yield fair, just, reasonable, and sufficient rates. The commission may provide changes to rates under this section for up to forty-eight months after the rate effective date.

Q. Is the Used and Useful Policy Statement still relevant under the MYRP Statute?

A. It provides helpful guidance although there are some changes under the new law that must be considered.

Q. What changes in the statute must be considered?

A. Prior to the passage of the MYRP Statute, the Commission had discretion to consider any property acquired or constructed during the rate effective period when setting rates and to change rates for up to forty-eight months after the rate effective date. In contrast, the MYRP Statute requires gas and electric companies to file multiyear rate plans beginning January 1, 2022 and further requires the Commission to ascertain and determine the fair value for rate-making purposes of the property that is or will be used and useful by or during each rate year.

> The commission *shall* ascertain and determine the fair value for rate-making purposes of the property of any gas or electrical company that is or will be used and useful under RCW 80.04.250 for service in this state by or during each rate year of the multiyear rate plan.[9]

The discretion that the Commission previously had to value property acquired or constructed by or during the rate effective period and to put such property into rates for up to 48 months after the rate effective date is now mandatory when a company files the required multiyear rate plan.

[9] RCW 80.28.425(3)(b) (emphasis added).

Q. Does the Commission continue to have discretion in terms of the methodology it uses to value property?

A. Yes, Both RCW 80.04.250(3) and the MYRP Statute give the Commission discretion in terms of determining the "standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates."[10]

Q. What are the implications of this statutory change in terms of the validity of the Used and Useful Policy Statement?

A. The Used and Useful Policy Statement provides helpful guidance in terms of the Commission's intention, prior to the passage of the MYRP Statute, as to the standard, formula, method or theory of valuation the Commission intends to use when considering plant that goes into service by or during the rate effective period. This guidance continues to be helpful under the MYRP Statute. However, there are limitations to the policy statement to the extent it conflicts with the MYRP Statute. As noted above, one key difference is that under the MYRP Statute, the Commission is required to value property for ratemaking purposes that is used and useful by or during each rate year of the multiyear rate plan.

[10] RCW 80.28.425(3)(d).

Q. How will PSE be presenting the information in this filing in conformity with the Used and Useful Policy Statement and the MYRP Statute?

A. As discussed in more detail below, PSE will be providing restated results,[11] the traditional pro forma period through December 2021, and four provisional pro forma periods, each for the years 2022 through 2025. PSE is proposing that the portion of the rates associated with utility plant that is requested for all four of the provisional pro forma periods be set subject to refund.[12] Actual and forecasted plant additions will be provided through 2025 segregated by period and categorized into types of investments: specific, programmatic, and projected spend.[13] Additionally, PSE has included amounts that are subject to refund in a separate tariff rider consistent with the Used and Useful Policy Statement.[14]

Q. Has PSE provided the requisite information prescribed in the policy statement?

A. Yes. In Exh. JAK-5, Mr. Kensok presents the detail of the board approved plant closings included in the multiyear rate plan detailed by year, by project or program and by category. Exh. JAK-5 further provides the witness who discusses each of the projects or programs listed. Mr. Kensok also explains how the in-service dates for the projects and programs within the multiyear rate plan are

[11] Policy statement, paragraph 21.
[12] *Id.* at paragraph 38.
[13] *Id.* at paragraph 16. Any board approved plant additions that are not considered specific or programmatic are considered projected.
[14] *Id.* at paragraph 34, page 12.

determined. The specific assumed in-service dates or closing assumptions that underlie the annual presentation in Exh. JAK-5 are included in the work papers.

Q. What other information is requested in the policy statement?

A. The following is a summary of the information the policy statement recommends be provided for provisional pro forma items[15] and where PSE has provided the information in this filing.

<u>Programmatic (starting at paragraph 34 of the policy statement:</u>

- **<u>Description of investment</u>** – Exh. JAK-5 provides the list of witnesses who discuss each of PSE's proposed programmatic and specific provisional pro forma adjustments.
- **<u>Estimated project cost</u>** – Contained in Exh. JAK-5.
- **<u>Expected in service date</u>** – The in-service year or closing assumptions are provided in Exh. JAK-5.
- **<u>Offsetting factors</u>** – The various witnesses who discuss each of the projects or programs provides discussion of offsetting benefits as applicable. Mr. Kensok discusses how offsetting factors are considered in developing the board approved plant additions and operations and maintenance ("O&M") spending that are used in the multiyear rate plan. Additionally, I provide below a list of offsetting factors included in this filing.
- **<u>Duplicate recovery considerations</u>** – All of the test year plant, including retirements, have been rolled forward to their expected value through the full multiyear rate plan as discussed below in Section VII within Adjustments 6.28/11.28 through 6.30/11.30[16] Additionally, as I discuss in Section VI, all entries that occurred during the test year to recognize deferrals have been removed.[17]

[15] Paragraphs 34 through 37 of the policy statement.
[16] Docket UE-200900 and UG-200901, et al. ¶ 209.
[17] UE-190529 Order 10 ¶ 16.

- **Demonstrate spending through historical trends** – Exh.SEF-22 provides historical spending levels for programmatic items.

Projected (starting at paragraph 35):

- **Level of spending** – The level of spending for investments in the projected category is provided by Mr. Kensok in Exh. JAK-5.
- **Cost controls** –Mr. Kensok provides testimony on PSE's governance process for corporate planning and how cost controls are considered in the process. PSE witness Kazi K. Hasan provides testimony on corporate level cost controls.
- **Specific need** – In addition to the testimony provided by Messrs. Kensok and Hasan, I discuss below the need to include all of PSE's board approved plant additions in the multiyear rate plan.
- **Cannot comingle O&M, rate base and offsetting factors** – As PSE is including all its board approved plant additions in the multiyear rate plan in this filing, it is not always feasible to provide grossed up reporting of all O&M, rate base and offsetting factors. I provide below a list of the offsetting factors included in this filing.
- **Identifiable and distinct escalation factors** – The escalation factors included in PSE's planning process, which are mainly used for purposes of planning O&M, are discussed by Mr. Kensok in Exh. JAK-1T.
- **Clear easily comprehensible models** – PSE has provided extensive work papers supporting its revenue requirement calculations.

Q. Why is it important for the Commission to allow the property into rates as PSE is requesting in this case?

A. PSE is facing an unparalleled period of transition. PSE witness Mr. Adrian J. Rodriguez addresses how PSE must continue to focus on the safety and reliability of its electric and natural gas systems while at the same time PSE must work to fulfill a vision for the future through its Beyond Net Zero initiative that aligns with CETA and, in addition, provides for the decarbonization of PSE's natural gas system. For the foreseeable future, PSE will continue to operate and maintain its existing system, while at the same time building one that is cleaner, more nimble, and focused on more equitable outcomes for those most historically disadvantaged.

Q. What are some of the challenges facing PSE in achieving its future vision?

A. As discussed by Mr. Hasan in Exh. KKH-1CT, PSE has experienced erosion of its financial health due to tax reform, the COVID-19 pandemic, and the actions taken by the Commission to mitigate the effects of rate increases in PSE's last general rate case in response to the pandemic. Additionally, as discussed in the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-1CT, trends in the power market continue to result in consistent and material under-recovery of power costs. In response to these challenges, PSE has had to constrain capital and O&M spending in order to maintain sufficient cash flow to meet its credit metrics so that it does not experience a ratings downgrade as discussed by PSE witnesses Kazi K. Hasan and Cara G. Peterman. These spending constraints have resulted in PSE being unable to meet certain of its Service Quality Indices ("SQIs"), as discussed in the Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T. For these reasons, it will take significant support to allow PSE to reach a point where it can successfully meet its SQI obligations as well as begin to fulfill its future vision to decarbonize its electric and natural gas systems.

Q. How will a multiyear rate plan help address these challenges?

A. Mitigation of regulatory lag will play a substantial part in restoring PSE's financial health, improving its deteriorating service quality, and accelerating the pace of decarbonization of its energy supply. The MYRP Statute goes a long way towards mitigating regulatory lag by requiring the Commission to include in rates the used and useful property for each year of the multiyear rate plan, and at a minimum, the property in service at the first rate effective period of a multiyear rate plan must be included in rates for that period.

Q. What has the Commission traditionally allowed when approving pro forma adjustments?

A. Traditionally, the Commission has only allowed provisional pro forma treatment for recovery of a few select projects that are estimated to be in service after the rate effective period.[18] However, as noted earlier, PSE is effectively maintaining its existing system while, by statutory mandate, it is simultaneously investing in a new and cleaner system. Limiting PSE to only a handful of adjustments for the next three years, consistent with the Commission's past practice prior to CETA and the MYRP Statute, will not adequately address regulatory lag for PSE over

[18] *Wash. Utils. & Transp. Comm'n v. Northwest Natural Gas, d/b/a NW Natural*, Dockets UG-200994, UG-200995, UG-200996 and UG-210085 (*Consolidated*), Final Order 05, 4-5, ¶¶15 and 16, (October 21, 2021); *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-200900, UG-200901, UE-200894 (*Consolidated*), Final Order 08/05, 88, ¶ 251, (September 27, 2021).

the duration of the multiyear rate plan due to the material nature of the investment PSE must make in its energy systems.

Q. Please elaborate on the material nature of PSE's investment in its energy systems.

A. Between the end of the test year and the third year of the multiyear rate plan, PSE is expecting to place in service $5.4 billion of utility plant that will be used and useful and providing service. To put this in perspective, the amount of utility plant PSE is expecting to put in service over the course of the multiyear rate plan is greater than the *total* gross utility plant on any other Washington utility's books as reported at the end of 2020. PSE is much larger than any of the other regulated utilities in Washington State and as such, will require commensurate support to adequately address regulatory lag during the outer years of a multiyear rate plan.

Q. Can you demonstrate how allowing only a limited number of pro forma adjustments has not adequately addressed regulatory lag in the past?

A. Yes, Exh. SEF-7, as summarized in Table 2 below, shows PSE's actual rate base[19] during the rate year of each of its last six general rate cases compared to the total rate base that was allowed.[20] The table also demonstrates that the level of growth in rate base between the amount allowed and the actual amount on a combined

[19] Production Tax Credits were excluded from actual rate base that was compared to the 2019 general rate case in order to be on a comparable basis.

[20] Allowed rate base includes the rate base from PSE's Cost Recovery Mechanism for Pipeline Replacement Tariff recovered under Schedule 149 ("CRM") to better align with the actual rate base reported which includes all CRM investment.

basis was not compensated for by customer growth.[21] This has been the case historically, before the need to transition PSE's energy systems. The requirements of CETA will exacerbate the gap if the Commission continues to limit the number of pro forma adjustments during the rate years of a multiyear rate plan.

Table 2. Comparison of Actual Rate Base vs. Allowed

Description	2006 GRC	2007 GRC	2009 GRC	2011 GRC	2017 GRC	2019 GRC
Combined Rate Base Above Allowed	12%	17%	10%	2%	7%	6%
Combined Customer Growth	5%	3%	2%	1%	3%	3%

Q. What other observations do you have about Exh. SEF-7 that the Commission should consider?

A. Of the twelve measurements[22] shown on lines 49 and 50 of Exh. SEF-7, there are only two isolated instances where rate base growth does not exceed customer growth. Additionally, for the more recent cases, bonus depreciation likely helped to narrow the gap between actual and authorized. And, most importantly, the gap between rate base growth and customer growth is greatest in the years when PSE was heavily investing in its system including the period after 2001 when PSE was acquiring owned resources to reduce its reliance on the market. This period, between the 2006 and 2011 general rate cases, is indicative of the period of

[21] For the 2017 and 2019 GRCs, the growth calculation was adjusted to recognize that once PSE's fixed production rate base was included in the fixed production decoupling mechanism, changes in customers/load were no longer allowed for this category of rate base.

[22] Electric and gas for each of the six general rate cases.

investment PSE must now enter. During that historical period, it was necessary to file multiple general rate cases in quick succession as that was the only tool available to address PSE's significant regulatory lag. Even then, the gap between actual and allowed rate base growth was as great as fourteen percent. The results for these years support PSE's request to include its full budget for plant closings and provide evidence that only allowing limited pro forma adjustments will not adequately address regulatory lag, especially in the context of a multiyear rate plan.

Q. Do the MYRP Statute and the policy statement allow for inclusion of all of a company's projected plant additions in provisional pro forma adjustments as PSE is proposing in this case?

A. Yes, as previously discussed both the MYRP Statute and the policy statement allow for the inclusion of all projected plant additions for setting rates in a multiyear rate plan. The multiyear rate plan requires the Commission to include plant in rates for each year of the multiyear rate plan. RCW 80.28.425(3)(d), like the policy statement, allows the Commission to use "any standard, formula, method, or theory of valuation" for determining the value of property to set in rates for the years within a multiyear rate plan provided that it arrives at "fair, just, reasonable, and sufficient rates."

Q. How would allowing PSE to include all of its forecasted capital additions result in rates that are fair, just, reasonable, and sufficient?

A. First, as previously discussed, RCW 80.28.425(3)(b) requires that used and useful plant be included in rates. Complying with the statute meets the fair, just, reasonable and sufficient standard as a matter of law.

Second, if PSE is to be well-positioned to stay out for the full three years and not have to file a new multiyear rate plan during that time,[23] PSE's expected investment in utility plant will need to be included in its rates.

Third, because PSE's level of investment and O&M will exceed its growth in revenues as it works to meet its clean energy, safety, and reliability obligations, as demonstrated in Table 2 above, PSE will experience regulatory lag during the multiyear rate plan that will impair its ability to meet these goals if recovery of rate period investment is not afforded.

It is for these reasons that PSE is including all of its expected plant additions in rates during the multiyear rate plan period. As stated above, all these plant additions will be categorized as specific, programmatic or projected in conformance with the policy statement. And, ultimately, PSE supports the safeguards for customers, including rates subject to refund and the earnings sharing mechanism set forth in the MYRP Statute. Balancing the need for a reasonable opportunity to timely recover the utility's prudently incurred costs

[23] RCW 80.28.425(5).

during the three-year multiyear rate plan with these statutorily required customer protections allows the resulting rates to be fair, just, reasonable and sufficient.

Q. How does PSE preserve the proper matching of benefits with the inclusion of all forecasted plant in a multiyear rate plan?

A. In allowing all utility plant in a multiyear rate plan, PSE is also providing all additional forecasted accumulated depreciation, plant retirements and accumulated deferred income taxes[24] associated with both test year plant as well as all post-test year plant. PSE is also providing all of its expected revenue growth throughout the multiyear rate plan. Additionally, all identified O&M expense offsets are being included as discussed below.

Q. What other offsetting factors are included in this filing?

A. The below list provides the significant offsetting factors that have been included in this filing[25]:

1. **<u>Revenue growth</u>** – Revenue growth (as well as decline) has been factored into this filing. Please see the Prefiled Direct Testimony of Birud D. Jhaveri, Exh. BDJ-1T, for a discussion of how the changes to revenue at current rates were factored into the multiyear rate plan. I discuss below in Section VII.A for Adjustments 6.01 and 11.01, the factors that have influenced the forecast of billing determinants on which Mr. Jhaveri's calculations were based. Over the multiyear rate plan, this adjustment increases revenue requirement on electric by $17.4 million,[26] while for natural gas, this adjustment reduces revenue requirement by $20.5 million.[27]

[24] Including excess deferred income taxes ("EDIT").
[25] Used and Useful Policy Statement, paragraph 25.
[26] Exh. SEF-6, page 1 (Adjustment 6.01) line 29 plus Exh. SEF-3, page 1 line 32.
[27] Exh. SEF-11, page 1 (Adjustment 11.01) line 26 plus Exh. SEF-8, page 1 line 27.

2. **Roll Forward of Test Year Plant** – As I discussed above, the test year plant has been rolled forward to its expected value in the rate years, which results in significant additions to accumulated depreciation and accumulated deferred income taxes ("ADIT"). Over the multiyear rate plan, this significant adjustment decreases the revenue requirement on electric by $231.1 million, while for natural gas, this adjustment reduces revenue requirement by $80.1 million.[28]

3. **Forecasted Retirements** – As discussed in Adjustment 6.30 and 11.30, PSE has incorporated the impact of estimated plant retirements based on a three-year historical average. Over the multiyear rate plan, this adjustment decreases the revenue requirement on electric by $16.7 million, while for natural gas, this adjustment reduces revenue requirement by $3.2 million.[29]

4. **Production Tax Credits ("PTCs")** – As discussed in Adjustment 6.55, PSE has incorporated the full value of the monetized PTCs. Over the multiyear rate plan, this adjustment decreases the revenue requirement on electric by $19.6 million.[30]

5. **Program Revenues** – PSE incorporated the estimated revenues for its various customer programs. Over the multiyear rate plan, this adjustment decreases the revenue requirement on electric by $2.6 million.[31]

6. **Regulatory Assets and Liabilities and Acquisition Adjustments** – As has been done historically, PSE has adjusted its various existing production related regulatory assets and liabilities to their rate year levels. Additionally, as this is a multiyear rate plan, PSE's Acquisition Adjustments have also been adjusted to the rate year levels. Over the multiyear rate plan, this adjustment decreases the revenue requirement on electric by $27.8 million.[32]

7. **Basis differences on forecasted ADIT** – As discussed in the Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T, PSE has provided the benefit of basis differences for PSE's forecasted plant additions when determining the associated ADIT.

8. **Contributions in Aid of Construction ("CIAC")** – PSE forecasts the contributions made by customers for customer driven work. Over the

[28] Exh. SEF-13, page 2, shows the revenue requirement by each adjustment discussed in Exhs. SEF-6 and SEF-11. Amounts reflected can be obtained from Exh. SEF-13, page 2, by summing all years for each electric and natural gas for Adjustment 6.29.

[29] Exh. SEF-13, page 2 Adjustment 6.30.

[30] Exh. SEF-13, page 2 Adjustment 6.55.

[31] Exh. SEF-6 Adjustment 6.01 lines 35 through 37.

[32] Exh. SEF-13, page 2 Adjustments 6.49 and 6.56. Amounts are net of increases for certain new regulatory assets which have been combined for ease of calculation as amounts are all included in one adjustment (Adjustment 6.49).

multiyear rate plan, PSE has included roughly $43.6 million as an offset to rate base for CIAC for electric, which would result in a roughly $4.4 million[33] decrease to the electric revenue requirement. On the natural gas side, $11.7 million has been provided as an offset to rate base resulting in a roughly $1.2 million reduction to the natural gas revenue requirement.[34]

Q. How are revenue and O&M expense included in this filing?

A. As discussed above, PSE is including full utility plant at its forecasted rate year levels. Accordingly, in order to provide for appropriate matching treatment, both the revenue and O&M expense for each rate year is also based on the Company's forecast.[35] The revenue included in each year of the multiyear rate plan is based on PSE's current forecasted customer counts and billing determinants and is supported by Mr. Jhaveri. The total O&M forecast is presented by Mr. Kensok and is set at a level that includes O&M offsets, stretch goals and expected productivity that holds O&M growth to a level that is lower than it would be without these measures. Mr. Kensok also provides an overview of PSE's business planning and forecasting process and demonstrates that the Commission can have confidence that the forecasted O&M contains appropriate offsets that will provide the proper matching to the forecasted utility plant requested in this filing.

Q. Is this consistent with the statute?

A. Yes. As previously discussed, the MYRP Statute allows the Commission to use any standard, formula, method, or theory of valuation reasonably calculated to

[33] PSE uses a ten percent rule of thumb to determine the relationship between rate base and revenue requirement.

[34] Exh. JAK-5.

[35] Used and Useful Policy Statement, n. 24.

arrive at fair, just, reasonable, and sufficient rates."[36] In recent orders including for general rate cases filed prior to the passage or effective date of the MYRP Statute, the Commission continued to rely on a known and measurable standard when deciding matters of recovery for O&M.[37] However, the Commission recognized it would further address treatment for expenses within the context of a multiyear rate plan.[38]

Q. Why is it appropriate for the Commission to allow forecasted O&M expenses in rates?

A. As stated above, the MYRP Statute provides that the Commission may use any valuation for O&M when setting rates. The statute also provides that utility plant at the first rate effective period must be valued for setting rates in that period. In order to provide proper matching, revenues and O&M should also be set at the level that will exist during that period.[39] Paragraph 22 of the policy statement states (emphasis added):

> WAC 480-07-510(3)(c)(ii), which defines pro forma adjustments, remains unchanged, applicable, and relevant. In particular, this rule defines the known and measurable standard and the offsetting factors standard, both of which are elements of the matching principle, and both of which are necessary to ensure that costs and offsetting benefits are <u>**accounted for during the period in which they occur**</u>.

[36] RCW 80.28.425(3)(d).
[37] Dockets UE-200900, UG-200901, et al. Order 08 paragraph 164.
[38] *Id.* at paragraph 165.
[39] *Id.* at footnote 22.

The same holds true for the matching of the net utility plant in each of the rate years. The Commission will be considering this request in the context of a multiyear rate plan with appropriate customer safeguards that will allow the Commission to set rates based on forecasted information. The earnings sharing mechanism I discussed previously that is required by statute provides an important protection that creates the appropriate framework necessary to allow rates to be set using forecasted O&M. Further, setting rates at the level of spending expected in the rate years will provide the proper matching to the net utility plant as well as provide the ability for PSE to stay financially healthy during the stay out period of the multiyear rate plan. As the forecasted O&M contains O&M offsets, stretch goals, and expected productivity that holds PSE's O&M growth to a level that is lower than if unconstrained, PSE's proposal provides a balanced approach with appropriate safeguards for approval by the Commission.

Q. Is PSE proposing any of its rates be subject to refund during the multiyear rate plan?

A. Yes. PSE is proposing that rates that are recovering estimated utility plant related items beyond 2021 be set subject to refund. PSE has determined the portion of its requested rate changes in each of the multiyear rate plan periods that is related to net utility plant and depreciation expense to determine the amounts that it is requested be subject to refund.

Q. Does PSE have a proposal for retrospective review of forecasted plant and expense that would be set subject to refund?

A. Yes. The Used and Useful Policy Statement requires a process for retrospective review.[40] PSE recommends an annual review. The initial review would occur shortly after new rates become effective for the first rate year (2023) to review the portion of the 2022 plant investment that was based on forecasts.

Q. Does the Commission provide guidance for the structure of the review process in its policy statement?

A. Yes. The Commission provides guidance for the structure of the review process starting at paragraph 40 of its policy statement. Generally, the reviews must provide sufficient information to determine that estimates used to set rates were valid and accurate, and they must provide parties due process.

Q. Did PSE consider a less frequent schedule for reviews to lessen administrative burden?

A. Yes. However, PSE felt that less frequent reviews would not necessarily lessen the administrative burden. An annual process would allow PSE and parties to develop a methodology that can be more easily repeated. In contrast, conducting the review of rate effective period investment all in the next general rate case

[40] *Id.* starting at page 13.

would be overly burdensome on PSE and parties in a proceeding that should rightfully be focused on the next multiyear rate plan.

Additionally, annual reviews will help alleviate the uncertainty that comes with having rates that are subject to refund; the less time rates are subject to refund the better for both PSE and its customers. Should a refund be necessary, it is best to return amounts sooner rather than later.

Q. What timing is PSE proposing for its annual review filings?

A. PSE would need enough time to finalize its year end audit and submit its Form 10-K before it could prepare the information needed for the annual review. An annual filing made on March 31st would allow for the external reporting of the year end results and would coincide with the timing PSE is currently using for the filing of the Commission Basis Reports ("CBR")[41] on which the earnings sharing calculation will be based.

Q. How much time is PSE proposing for the annual review process?

A. Initially, PSE proposes that the annual review process be a three-month process. However, as time progresses, these annual reviews should become easier due to the learning curve in that parties will have developed a recurring process that

[41] WAC 480-90-257(1) and WAC 480-100-257(1). Per statute, CBRs are due within four months of the end of a utility's fiscal year, which would be April 30th for PSE. However, PSE is required to file its CBR by the end of March as it is the basis for its existing earnings sharing test that is currently administered in its annual decoupling filings which occur at the end of March.

becomes familiar. Eventually, PSE anticipates reviews can be conducted within one to two months.

Q. Can you please summarize the information in this filing that PSE is proposing will be subject to review and potential refund?

A. As discussed above, PSE is including all of its expected plant closings in its multiyear rate plan filing. The plant closings have been categorized as specific, programmatic, and projected in accordance with the policy statement. The below table provides a snapshot of the resulting number of pro forma adjustments across the time period of this filing. The expected capital additions have been categorized into fourteen specific, seventeen programmatic, and two customer driven provisional pro forma adjustments. Those expected capital additions that do not fall into those thirty-three[42] provisional pro forma adjustments are included in one electric and one gas projected provisional pro forma adjustment.

Table 3. Categories and Timing of Expected Capital Additions Subject to Refund

(in millions) Category	(Gap) 2022	(RY1) 2023	(RY2) 2024	(RY3) 2025	Total	Count
Specific	$ (332.9)	$ (40.6)	$ (329.2)	$ (519.7)	$(1,222.4)	14
Programmatic	(401.9)	(757.0)	(662.0)	(739.1)	(2,560.0)	17
Programmatic Customer Driven	(124.3)	(108.6)	(100.8)	(94.3)	(428.0)	2
Projected	(150.6)	(241.3)	(168.8)	(192.4)	(753.2)	-
Total	$(1,009.8)	$(1,147.4)	$(1,260.8)	$(1,545.5)	$(4,963.6)	33

[42] Programs that are common to electric and natural gas such as AMI deployment are considered one program for purposes of this summary. Because of this, there will be more than twenty two discrete provisional pro forma adjustments.

Q. If PSE is presenting all expected capital additions, how is PSE proposing that parties will conduct their review?

A. PSE is proposing an annual retrospective review on a portfolio basis that will be conducted in its annual review filings. A retrospective review using a portfolio basis allows for actual costs for projects that are above or below their estimated amounts to be accepted if they were prudently incurred, provided that on a portfolio basis their combined costs are within reason compared to what was used to set rates.

Q. What do you consider to be the level of costs that would be within reason relative to what was used to set rates?

A. If PSE's variances between estimated and actual amounts on a portfolio basis, both positive and negative, do not result in a materially lower revenue requirement, then PSE should not be required to refund rates for the period. Following the threshold used in the MYRP Statute as a guide, if PSE's recalculated revenue requirement that is subject to refund is not less than the equivalent of fifty basis points[43] on rate of return from the actual refundable revenue requirement set, then such rates should be considered within reason and require no refund.

[43] RCW 80.28.425(6).

Q. Why is the earnings threshold from the MYRP Statute a reasonable basis to use in the portfolio review process?

A. The statute does not require PSE to defer earnings for later consideration until the Company shows it is over-earning its allowed rate of return on a Commission basis in its annual CBRs by fifty basis points. Assuming all things were equal in a utility's annual CBR to what is set in rates except the level of spending on its provisional pro forma portfolio, the statute would allow a utility to retain over-earnings that resulted from those variances until it reached the fifty basis point threshold. Therefore, it follows that a reasonable threshold to set for the annual portfolio review is a fifty basis point impact on rate of return.

Q. Please describe in more detail what information will be provided in PSE's annual review filings that will allow parties to test whether the portfolio results are within the proposed threshold and therefore within reason.

A. PSE will use the work papers from its compliance filing and make no changes except to use actual plant closings for the period under review to recalculate what the revenue requirement and deficiency should have been based on the actual information. If the results show that the variance between the compliance and recalculated revenue requirement is more than fifty basis points of rate of return on rate base, then a refund of the amount above the fifty basis point threshold would be required. The below table uses the electric system results as an example and assumes plant closings were $100 million less than expected and depreciation expense was $28 million less than expected. The resulting revenue requirement would be $35.4 million less than actually set in rates which would be more than the $27.9 million, fifty basis point threshold resulting in the need for a refund of the difference between the $35.4 million reduction in the revenue requirement and the $27.9 million threshold. This is a simplified example and does not take into consideration load changes and other variables that may need to be considered.

Table 4 – Example Portfolio Threshold Calculation

Line	Revenue Requirement	Based on Estimates 2022 Electric	Based on Actuals 2022 Electric	Difference
6	(in millions)	(Exh. SEF-4)		
7	Rate Base	$ 5,585.4	$ 5,485.4	$ (100.0)
8	Rate of Return	7.39%	7.39%	7.39%
9	Return Requirement	$ 412.8	$ 405.4	$ (7.4)
10	Operating Expenses (w/ RSIs on Def)	1,952.2	1,924.2	(28.0)
11	Revenue Requirement	$ 2,365.0	$ 2,329.6	$ (35.4) *
12				
13	Authorized ROR plus fifty basis points	0.50%		
14	Fifty basis point threshold (line 13 x line 7)	$ 27.9		
15				
16	* If above -$27.9 million, a refund would not be required			

Q. Would there be any other adjustments needed to the amount calculated under the threshold above?

A. Not specifically. However, as discussed in the previous section, the amount of refund determined in an annual review should reduce the amount of the over-earnings deferred under the statutory earnings mechanism so as to prevent a duplication of the refunded amounts.

Q. Would this be the only test applied in the review process to determine the need for a refund?

A. No. Parties would also be able to review any outstanding prudency considerations that the Commission might determine remain subject to review after the order has been granted. If issues are raised in the review for which the Commission provides a final determination, such items could result in a refund even if the above threshold calculation is not triggered.

Q. Has the Commission provided guidance on the portfolio approach for review of provisional pro forma adjustments previously?

A. Yes. In considering the settlement of Northwest Natural Gas's ("NWN") recent general rate case, the Commission allowed the use of a retrospective review using a portfolio basis, even though such an approach was not strictly consistent with the Used and Useful Policy Statement. The Commission found the approach to be reasonable considering the specific facts presented and noted that the approach does not permit NWN to assess a surcharge for under-recovered amounts.[44] By accepting the portfolio review process, the Commission made clear that its decision was based on the fact that the specific projects to be reviewed were in the late stages of planning and that the risk that the portfolio of eight projects would

[44] *WUTC v. Northwest Natural Gas*, Dockets UG-200994 and UG-200995, et al. ¶25.

exceed their estimated amounts was low. The Commission also made clear that its decision was not precedent setting.[45]

Q. Is PSE's proposal for portfolio review similar to the circumstances in the NWN rate case?

A. No. PSE is requesting provisional treatment for all expected capital additions, not a limited number of additions, and many of the projects are not in the late stages of planning.

Q., Why should the Commission allow the portfolio approach in PSE's case?

A. Now that utilities are required to file multiyear rate plans and the Commission is required to include estimated investment in rates to address regulatory lag and allow utilities to maximize the length of multiyear rate plans, rate recovery should evolve to take into consideration the way utilities must manage their business during the multiyear rate plan. PSE has robust controls and governance around its capital planning process. These processes are discussed in detail by multiple PSE witnesses including Ronald J. Roberts and Suzanne L. Tamayo in their Prefiled Direct Testimonies in Exhs. RJR-1CT and SLT-1T respectively, as well as by PSE witnesses Joshua A. Kensok and Roque B. Bamba. Over the course of a multiyear rate plan, there will be times when, due to unforeseen circumstances, PSE will not spend or close projects under the timing it originally planned. That is the nature of running a complex business. As discussed by the previously

[45] *Id.* at 8 ¶27.

mentioned witnesses, PSE has robust controls and governance in place to be able to adapt to changes in business needs and external circumstances that allow the Company to manage to its overall forecasts in a prudent manner. It is much like managing a personal household budget. If your car unexpectedly breaks down, you make the repair and adjust your spending for example, by not installing a new backyard fence for a few more years. Both actions are reasonable given the circumstances, and the homeowner should not be penalized for repairing the car instead of installing the fence. Similarly, rate making under a multiyear rate plan should adapt and allow the flexibility for companies to adjust and make the prudent decisions necessary to run their business without being penalized under an overly prescriptive review process that demands costs and timing of expenditures remain static over a multiyear period. Indeed, maintaining flexibility and avoiding overly prescriptive processes are stated as goals of the policy statement.[46]

Q. Are there other factors the Commission should consider when determining if a portfolio review is appropriate?

A. Yes. The approach set forth in the Used and Useful Policy Statement—to use accounting petitions to account for under-recovered costs—does not meet the Commission's stated goal of supporting a streamlined process.[47] Accounting petitions have the potential to create incremental workload that is not value added.

[46] Policy statement at ¶28 (2) and (3).
[47] *Id.* item (4).

Instead, the Commission should be allowed to focus on validating a company's controls and governance practices to obtain the confidence that would allow for the portfolio approach. Such an approach is similar to that taken by a utility's external auditors who provide unqualified opinions over the company's financial statements. A combination of controls and specific testing provides the auditors assurance that the financial statements are fairly and appropriately presented. The Commission can use a similar approach under its statutory mandates for rate setting.

Q. Are there other unintended consequences that could occur if the Commission does not use a portfolio approach?

A. If, for example, the Commission only scrutinizes projects whose actual costs are less than estimates used when setting rates, it could have the potential to create bad policy by unintentionally placing pressure to spend up to the amount of budget included in rates, even if such spending is not needed.[48] While the review process is certainly intended to make sure this situation does not occur, it would be much better for the Commission to allow for a review process that recognizes the way utilities manage their business, which would provide for a balanced approach that is not prone to manipulation.

[48] For the record, PSE would not engage in such behavior as the reputational risk far outweighs any perceived upside that would result.

Q. Has the Commission allowed for any processes that are similar to a portfolio review?

A. Yes. PSE's natural gas Cost Recovery Mechanism ("CRM") filed pursuant to Docket UG-120715 provides annual recovery of investments approved in PSE's Pipeline Replacement Program Plan ("PRPP").[49] As part of the CRM process, rates that are set each year contain eleven months of actuals and one month of forecast information for the month of October. These estimated amounts are trued-up in the following year's CRM rate filing.

There is an important similarity in this process that is helpful when considering what to approve for multiyear rate plan reviews. In the CRM, PSE forecasts the projects that will close in October and their estimated cost. Then, in the following year's filing, PSE provides the actual amounts that went in service for October, which is subject to final review. There are typically multiple projects included in each estimated and final amount for October. Some project costs come in higher and some come in lower by the final review. Additionally, some new projects that were not anticipated in the prior year are placed in service, and some that were anticipated are not placed in service until after October. The Commission allows for a universal true-up in each year's CRM. It allows a true-up of all differences due to estimates versus actual closings and for timing differences. It does not require that the projects that come in higher than their estimated amount be

[49] PSE's PRPP is reviewed by the Commission's pipeline safety staff and approved by the Commission bi-annually.

capped at the level at which they were previously approved; it essentially allows the projects that came in less to offset the overages. Nor does it require specific treatment for projects that closed early or late. This process can also work for PSE's multiyear rate plan.

For all the reasons discussed above, PSE respectfully requests that the Commission approve PSE's retrospective review using a portfolio approach.

Q. Is it reasonable to expect parties to conduct their reviews in one to three months?

A. Yes. The CRM filings referenced above contain many discrete projects within the same CRM program. In recent years, Commission Staff has been able to conduct their review of these filings within two months. Another example would be PSE's annual Purchased Gas Adjustment mechanism filings. These filings, which approve all of the spending for PSE's gas costs from the prior year, as well as the forecasted gas costs for the ensuing year, are conducted in one and a half months. These examples show that the Commission, its staff and others have found ways to streamline their review processes so that they could be conducted over a relatively short period of time, which gives us confidence that these lessons could be applied to their review of PSE's costs in a multiyear rate plan.

Q. Can you provide a more specific example for how parties might be able to streamline their review process while maintaining an adequate level of assurance?

A. As noted in the testimony of Mr. Kensok, PSE anticipates placing up to $1 billion of plant in service per year through the end of the rate plan. While the review of this magnitude may not seem possible in the proposed time frame, parties can utilize general audit and attestation concepts in designing their review process to gain comfort over PSE’s expenditures without reviewing all costs and programs.

Parties can conduct review procedures to gain comfort that PSE’s governance, processes and procedures are appropriately designed and operating effectively to ensure capital expenditures are planned for and executed in a prudent manner for a population of expenditures subject to review. Should parties not find any process design or execution issues, they can gain comfort that the remaining expenditures and programs have gone through the same process and would garner similar results.

Q. What types of procedures can reasonably be performed for parties to get comfortable?

A. There are three broad categories of procedures that can be completed as part of the review: 1) process review 2) control testing and 3) substantive testing.

Process Review

Mr. Kensok has provided testimony supporting PSE's corporate authorization process which substantially all investments go through. This testimony provides the needed information for parties to conduct their review of the process PSE completes when making investment decisions which benefit customers. Therefore, the process review can be conducted in this proceeding, before the first annual review. In each subsequent annual review, Parties can ask for updated process information to understand what, if any, changes have been made to this process in future reviews to ensure they are comfortable the process continues to be designed with the necessary level or rigor.

Control Testing

An important part of the process discussed by Mr. Kensok is the application of judgment in the governance process surrounding project authorization and funding as well as the need to remain flexible in responding to changes in the planning environment. Proper testing will recognize that the process will need to employ informed judgment and to respond to dynamic circumstances. Testing should be designed to allow for the nature of the process, to confirm PSE properly followed its governance process that is designed around the need to be flexible in its planning process. With this in mind, parties can test a sample of programs which had expenditures during the review period to verify they went through the above process. If all of the selected items have been through the process as designed, parties can gain comfort that the remaining unselected items did as well.

Substantive Testing

Parties can select a sample of actual closings during the review period and request supporting documentation to assess that the spending was appropriate, including that these expenditures went through the authorization process to further validate PSE's controls. As parties will have assessed PSE's projects and programs for need and prudency in this rate case filing, the review process would focus only on the execution of the projects and programs, testing for such things as being within a reasonable amount of budget, closing on the expected time frame and closing to the expected categories of rate base. In the event there are new projects that occurred under PSE's established governance processes in lieu of other delayed projects, documentation for need and prudency could be tested at that time.

The combination of the three above procedures can give parties assurance that PSE is operating in a prudent manner for its entire portfolio, while also providing evidence this is the case, without testing every transaction in the review period.

Q. What might a potential test plan look like?

A. The purpose of the multi-faceted testing approach is to gain comfort over an entire population without testing the entire population. Therefore, the testing approach should be designed in a way which ensures all areas of a population received some sort of testing consideration.

The first procedure of understanding and reviewing PSE’s process review covers the entire portfolio and provides assurance of the steps PSE takes when determining investment decisions, but does not provide specific evidence of the expenditures within the review.

The second procedure of completing control tests should be completed on a sample of the entire population regardless of materiality to determine whether PSE is acting consistently across its portfolio. The test could evaluate whether PSE has followed the procedures set out in its corporate authorization process as designed. This considers the full population, but at a lower level of detail than in the process review and on specific transactions in the review period.

Finally, substantive testing could be completed on a sample of the most material projects or programs. This will provide parties the ability to review the largest amount of the portfolio financially through the least burdensome testing approach. The test could consist of reviewing detailed support of expenditures which have been placed in-service in addition to confirm those expenditures went through the appropriate corporate authorization process, satisfying the control test while substantively testing the expenditure. This allows for an important portion of the portfolio (large expenditures) to be tested at a detailed level on the activity under review.

The combination of all three procedures provides for the entire portfolio to be considered for testing at some level, with a specific focus on the items with the greatest impact.

Q. What would happen if PSE does not "pass" a control or substantive test?

A. Generally, if a control test does not initially pass, additional selections are made to understand if the occurrence is an outlier or indicative of a larger issue. In certain situations explanations by the Company as to why a program did not go through the normal process might be a reasonable response and not be deemed an exception. Should a reasonable number of additional selections pass, parties can gain comfort the exception was indeed an outlier and that the control is operating effectively for the remainder of the portfolio. If there are continued control exceptions, a larger sample of substantive tests should be completed in order to understand if the lack of controls had an adverse effect.

Similar to above, if exceptions in the substantive test are found, additional selections should be made to understand if this was an outlier or indicative of activity in the remainder of the portfolio. Additional selections should be made until appropriate assurance is gained that the portfolio is planned for and executed in a prudent manner.

Q. Please explain what tariff schedules PSE is proposing be used to administer setting rates that are subject to refund.

A. In concert with base rates, PSE is proposing two new rate schedules, Schedule 141R, Rates Subject to Refund Rate Adjustment and Schedule 141N, Rates Not Subject to Refund Rate Adjustment to administer the rates that are subject to refund and not subject to refund. The rates during the multiyear rate plan that PSE is proposing not be subject to refund will be different in each year of the multiyear rate plan. This is due to such items as the continued decline in test year utility plant and depreciation expense and changes in O&M. Base rates will only include the deficiency through the traditional pro forma period, none of which will be subject to refund, as shown in column line 65 on Exhs. SEF-4 and SEF-9. After 2021, the revenue changes will be comprised of rates that PSE is proposing be both refundable and non-refundable. In order to prevent the need to change base rates each year of the multiyear rate plan, the rates PSE is proposing be non-refundable have been included in Schedule 141N, and the rates PSE is proposing be refundable have been included in Schedule 141R.

Q. Please further explain the new tariff rates.

A. Rates for the four provisional pro forma periods (2022 through 2025) associated with the recovery of depreciation and rate base for utility plant estimated to close or retire after 2021 have been included in Schedule 141R. Schedule 141N includes the rates associated with the recovery of costs not subject to refund, which include all other costs not included in Schedule 141R.

As discussed above, PSE is proposing an annual review process to review the actual investment made compared to that which was used to set rates for the prior calendar year. At the conclusion of the annual review process, assuming no refund is required, rates would be moved from the Schedule 141R tariff and transferred into the Schedule 141N tariff to recognize that the costs have been reviewed and are no longer subject to refund.

Q. Please elaborate on the timing of the annual review filings and what the desired outcomes would be.

A. PSE is proposing an annual review filing to be made by March 31st each year to review the plant investment from the prior calendar year and to confirm that the amounts included for recovery in rates is appropriate. At that time, PSE would also have its annual CBR available and any associated deferral that might need to be made under the statutory earnings mechanism also available for review. The earnings test deferral balance would be held until the completion of the review in order to determine if the amounts originally booked should be reduced by any amounts deemed to be refundable as a result of the annual review.

Q. What other information would be included in the filing?

A. The review filing would include up to four tariff updates. The first would be to set a Supplemental Rate Credit in Schedule 141R, effective July 1st, should customer refunds be necessary as a result of the review filing. The second would also be effective July 1st and would transfer from Schedule 141R to Schedule 141N the portion of rate recovery associated with the costs that have been reviewed and are no longer subject to refund. The third would be effective January 1st of the following year to recognize any required adjustment for any impacts on the following year's rates that would result from amounts in the current period being determined to be refundable. The fourth would also be effective January 1st of the following year for the commensurate change to low income discount rates. I have provided an overview of the proposed review filing schedule in Exh. SEF-25.

Q. What other considerations would be included in the annual review filings?

A. As reflected above, PSE anticipates rates from this multiyear rate plan to be effective January 1, 2023. PSE would file its first review filing by March 31, 2023, to review the investments associated with the first provisional pro forma adjustment period, calendar year 2022. At the conclusion of that filing, rate recovery associated with the 2022 provisional adjustment would be transferred from Schedule 141-R to Schedule 141-N to reflect that costs had been reviewed and the results are no longer considered provisional and subject to refund. Should there be material adjustments necessitating refunds to customers, the filing would include a Schedule 141R Supplemental Rate Credit with a proposed effective date of July 1st of that year. The filing would also include any updates to rate year two (2024) of the multiyear rate plan with rates effective January 1, 2024 resulting from the review.

This process would continue annually, with the final review filing occurring in March 2026, to review the 2025 provisional adjustments and implement any Supplemental Rate Credit that may result from that review.

Q. What information would PSE provide in its initial filing for the retrospective review?

A. PSE will provide the following in the initial filing of its annual retrospective review as discussed in the policy statement:[50]

1. Actual plant closings categorized in the same manner as they were categorized in this proceeding[51] so that they can be compared to the forecasted amounts used when setting rates. Should it be determined that rates need to be recalculated due to a significant variance in project or program prudency, timing or cost, PSE will then calculate the commensurate accumulated depreciation, accumulated deferred income taxes, retirements, and depreciation expense needed to recalculate rates.
2. In service dates for Specific investments.
3. Narrative explanations for any significant deviations between actual and forecasted investment.
4. A proposal for any tariff change needed for amounts to be refunded to customers based on actual amounts incurred.

[50] Policy statement ⁋34.
[51] *See* Table 3 above.

Q. What else would occur during the review process?

A. After reviewing PSE's initial filing, PSE could conduct a walk-through with interested parties. Parties could then engage in reasonable discovery. The presumption is this final stage of prudency review can be expedited as parties will have had the benefit of the extensive review in this general rate case to determine need and establish confidence in PSE's governance and controls. The final review of cost and project timing should be less burdensome and more subjectively determined. If adjustments to the filing arise as a result of parties' reviews, PSE would make a substitute filing. Assuming no party finds a need to file for adjudication, the Commission can approve the filing in an open meeting.

III. PSE'S COVID DEFERRAL

Q. Please provide a background of the accounting petitions that allow the State's investor owned utilities to defer costs and savings associated with the COVID-19 pandemic.

A. In 2020, the Commission opened Docket U-200281 ("Disconnects Docket") related to successive proclamations issued by the Governor ("Proclamations" or "moratorium")[52] regarding the suspension of 1) disconnection of service or refusal to reconnect residential customers for non-payment; and 2) charging late fees or reconnection fees during the pandemic. In the Disconnects Docket, the Commission adopted a revised term sheet as presented by Commission Staff that

[52] Proclamations 20-23.2 and 20-23.4.

addressed processes for how to emerge from the moratorium, including resumption of charging fees, additional customer funding and support, the credit and collections process, cost recovery, and reporting. As a means of achieving a comprehensive plan, companies separately filed accounting petitions to allow for the ultimate determination of the cost recovery provisions that were contemplated in the Disconnects Docket. PSE's petition was filed under Dockets UE-200780/ UG-200781 ("COVID accounting petition").

Q. What categories of costs and savings were allowed for deferral in PSE's COVID accounting petition?

A. The Commission allowed PSE to defer the following categories of costs to a FERC 186 "Other deferred debits" account and savings to a FERC 253 "Other deferred credits" account:[53]

1. Direct costs incurred in response to the pandemic.[54]
2. Cost savings experienced as a result of the pandemic.[55]
3. Bad debt expenses above a baseline.
4. Customer bill assistance for programs resulting from the Disconnects Docket.
5. Disconnection and late payment fees below a baseline.

[53] Docket UE-200780 and UG-200781 Order 01, pages 7 through 9.

[54] Examples of direct costs include costs for cleaning supplies, personal protective equipment and medical testing.

[55] Examples of costs savings include reduced travel, parking and office supplies expenses.

Q. What other conditions did the Commission order in PSE's COVID accounting petition?

A. The Commission required that PSE report its normalized earnings during the deferral period at the time PSE seeks to recover the deferred net costs. The Commission further required that PSE work with Commission Staff and other stakeholders to develop an appropriate methodology for tracking its normalized earnings,[56] which PSE did. Commission Staff's preference is to use a company's annual CBR. For deferral periods for which a CBR has not yet been filed, Staff indicated that calculating the rate of return in a similar manner as is done in a CBR for the trailing twelve-month period would be acceptable. For purposes of documenting its earnings position when recording its quarterly deferrals, PSE has been using the trailing twelve-month measurement of its normalized earnings ending with the month prior to the quarter end.

Q. Is PSE requesting recovery of the deferral of net costs under the COVID accounting petition in this proceeding?

A. Partially. PSE is requesting recovery of its deferred direct costs, disconnection, reconnection and late fee revenues and offsetting cost savings (categories 1, 2 and 5 above) in this proceeding. For the deferrals associated with bad debt expense and customer assistance programs (categories 3 and 4 above), PSE requests the

[56] Docket UE-200780 and UG-200781 Order 01 ¶30.

Commission authorize PSE to recover these deferrals as part of its annual Schedule 129 Low-Income rate filing in August 2022.

Q. Why is PSE proposing to recover deferred bad debt expense and customer assistance in its Low-Income filing?

A. RCW 80.28.068(1) requires expenses and lost revenues resulting from discounts, grants, or other low-income assistance programs to be included in rates to other customers. The mechanisms by which PSE has included such programs in rates is Schedule 129, which includes the low-income Home Energy Lifeline Program ("HELP") and more recently has included the administration of the Supplemental Crisis Affected Customer Assistance Program, which is the program for the customer assistance deferrals under the COVID accounting petition. Both the customer assistance and bad debt expense categories of PSE's COVID deferral relate to customer balances that are unable to be paid and are appropriately recovered through Schedule 129. They include expenses and lost revenues from State and Commission mandated assistance programs to mitigate the financial effects of the pandemic.

Regarding the bad debt category of PSE's COVID deferral, PSE is only allowed to seek recovery for the amount of eventual write-offs[57] that exceed its baseline.[58] As write-offs of customers' accounts have all but ceased due to the Disconnects

[57] Bad debt expense recorded on a company's books is an estimate of the write-offs that will occur on the revenue that is charged within the reporting period. The accounting petition requires that the actual write-offs that eventually occur be the amount that is deferred, not the estimated bad debt expense accruals.

[58] PSE's bad debt expense baseline is $18.4 million for electric and $4.5 million for natural gas.

Docket, it will take more time to determine if PSE's write-offs will eventually exceed the amount of bad debt expense that has been recorded since the petition was approved.[59]

Recovery in Schedule 129 will provide the ability to true up PSE's recovery of these deferral amounts, which is consistent with how other customer funding amounts are recovered. For these reasons, the Commission should authorize PSE to recover these portions of the COVID deferrals within the Schedule 129 annual filings.

Q. What changes should be made to the current filing if the Commission does not allow the bad debt expense and customer funding deferrals to be recovered through PSE's annual Schedule 129 low-income filing?

A. Since PSE's annual low-income filing does not occur until August 2022 for rates effective October 1, 2022, there will not likely be time in this procedural calendar to know whether or not the Commission will allow recovery of PSE's bad debt or customer funding deferrals until later in the proceeding. If PSE is not allowed to recover these two deferrals in the low-income filing, PSE respectfully requests that the Commission include recovery of these deferrals in PSE's compliance filing. Parties can engage in discovery in this case to validate the ongoing balances for these deferrals and provide their recommendations to the

[59] PSE is currently deferring its bad debt expense as a proxy for the eventual write-offs that will occur, but sufficient time has not passed to determine if the amount of the deferral for bad debt expense will eventually be supported by actual write-offs.

Commission for recovery in this proceeding should recovery not be allowed in the annual low-income filings. The current balance of these deferrals is being provided below.

Q. What is the most recent balance of PSE's COVID deferrals?

A. The balance of PSE's COVID deferrals as of September 30, 2021 is shown in Table 5 below. The description for how the amounts being requested for recovery in this proceeding were calculated is included later in my testimony in Section VII in Adjustments 6.27 and 11.27.

Table 5. COVID Deferrals as of September 30, 2021

Electric Categories	Q4 2020*	Q1 2021	Q2 2021	Q3 2021	Combined Total
Direct Costs	257,591	106,976	116,135	28,212	508,914
Direct Savings	(552,968)	(12,154)	(276,622)	(445,734)	(1,287,478)
Bad Debt Expense Accrued Above Baseline	-	1,694,529	2,349,857	2,956,913	7,001,299
Foregone Late Payment Fees	838,744	540,490	536,073	538,797	2,454,104
Foregone Disconnection Fees	(77,912)	52,490	68,747	23,929	67,255
COVID-19 Bill Assistance Program	-	-	8,626,022	5,199,522	13,825,544
Totals	**465,455**	**2,382,331**	**11,420,212**	**8,301,639**	**22,569,637**

Gas Categories	Q4 2020*	Q1 2021	Q2 2021	Q3 2021	Combined Total
Direct Costs	127,336	52,599	57,568	12,891	250,394
Direct Savings	(277,811)	(4,294)	(139,325)	(225,591)	(647,021)
Bad Debt Expense Accrued Above Baseline	-	655,380	469,481	337,614	1,462,476
Foregone Late Payment Fees	332,597	211,814	211,775	211,853	968,039
Foregone Disconnection Fees	10,002	9,106	10,264	11,180	40,552
COVID-19 Bill Assistance Program	-	-	1,912,594	863,863	2,776,457
Totals	**192,124**	**924,606**	**2,522,357**	**1,211,810**	**4,850,897**

Q. Was PSE under-earning when it recorded its COVID deferrals?

A. Yes. PSE's COVID deferrals were approved beginning September 3, 2020.[60] The Commission required that PSE show that it was not over-earning when the deferrals were recorded.[61] Table 6 below shows the multiple data points that demonstrate PSE was under-earning when recording its COVID deferrals. It is important to note on line 4 of the table, that even after annualizing the impacts of PSE's recent general rate case, PSE has failed to earn its authorized rate of return. Line 6 presents the twelve months ending August as that is the information available when analyzing the Company's earnings position for recording its quarter end deferral.

Table 6. Recent Normalized Rates of Return

			Electric		Natural Gas	
Line	**Measurement Date**	**Basis**	**Actual**	**Authorized**	**Actual**	**Authorized**
1	2020 Commission Basis Reports					
2	(UE-210212 and UG-210213)	Normalized	6.54%	7.47%	6.37%	7.47%
3						
4	Restated Results (Exh. SEF-4 and SEF-9)	Normalized and Annualized	7.15%	7.42%	6.91%	7.42%
5						
6	Twelve Months Ending August 2021	Normalized	6.59%	7.40%	6.95%	7.40%

[60] Docket UE-200780 and UG-200781 Order 01, ¶32.
[61] *Id.*, ¶30.

Q. Was there a dispute in PSE's COVID accounting petition regarding the recovery of deferrals of lost revenues associated with disconnection and late payment fees?

A. Yes. Public Counsel and Commission Staff argued that the Governor's Proclamations would prohibit the recovery of these deferrals.[62] The specific language from the proclamation states there is a prohibition on "all energy, telecommunications, and water utilities in Washington State from disconnecting certain residential utilities and from charging related late payment and reconnection fees."[63] PSE's view is that the proclamation does not prohibit recovery of such fees, it only prohibits companies from charging those fees as was being done following past practice. PSE believes the intent of the language is that these fees should not be charged to the specific customers whose account status would otherwise result in such fees being applied to their specific accounts. It does not prohibit the recovery of such fees from customers in general, in much the same way companies are allowed to recover their bad debt expense in rates from all customers, even though bad debt expense is the result of specific customer accounts. The amount of these fees that PSE has deferred is net of the savings in variable costs associated with the disconnection and reconnection activities. For this reason, PSE believes this portion of its requested deferral should be allowed for recovery.

[62] *Id.*, ¶¶ 24-25.
[63] Proclamation 20-23.2 issued by Governor Inslee on April 17, 2020, page 3 (emphasis added).

IV. CURRENT RATES ARE INSUFFICIENT

Q. Please explain Commission Staff's "threshold requirement" for filing a general rate case.

A. In recent cases, Commission Staff has advocated and the Commission has opined that a company is required to establish that its current rates are not sufficient as a "threshold requirement."[64] In order to do so, PSE must demonstrate that it is currently earning below its authorized rate of return and will continue to be so absent rate relief.

Q. What are PSE's rates of return that were last authorized by this Commission for its electric and natural gas operations?

A. The Company's current authorized rate of return for both electric and natural gas operations is 7.39 percent.[65]

Q. Has PSE met the threshold that current rates are insufficient?

A. Yes. PSE's actual and restated results of operations for the twelve months ended June 30, 2021 are 5.42 percent and 7.15 percent for electric operations[66] and 6.03 percent and 6.91 percent for natural gas operations.[67]

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[64] *See, e.g. WUTC v Puget Sound Energy*, Dockets UE-180532 an UG-180533; *WUTC v Cascade Natural Gas Co.*, Docket UG-200568.

[65] *See* Final Order No. 8, Dockets UE-190529, UG-190530, et al.

[66] *See* Exhibit SEF-4, page 1, line 49 columns a and c.

[67] *See* Exhibit SEF-9, page 1, line 49 columns a and c.

Q. Do you believe that such a threshold is still relevant in the context of a multiyear rate plan?

A. No. Multiyear rate plans are forward looking mechanisms as opposed to modified historical test years, which are backward looking mechanisms. Even though WAC 480-07-510(3)(c)(i) requires the presentation of restated results, I believe such a presentation is no longer relevant in the context of statutorily required multiyear rate plans. However, I continue to provide this presentation because it is required by Commission rules.

Q. What steps has PSE taken to avoid having to file a rate case?

A. As I discussed previously in my testimony, the trajectory resulting from the transition toward decarbonization cannot be supported through current rates. The growth in investment cannot be supported through customer growth, which is a fundamental reason for the need for a multiyear rate plan. Even so, PSE has taken many steps to manage its business to avoid having to file a general rate case. I have discussed some of the steps taken earlier in my testimony. A detailed discussion of PSE's efforts is provided by PSE witness, Kazi K. Hasan.

V. SUMMARY OF PROPOSED ELECTRIC AND NATURAL GAS REQUESTED REVENUE

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

A. PSE is requesting a net revenue change as summarized in Table 7 below:

Table 7. Total Revenue Change Requested

Description	2023 Electric	2023 Gas	2024 Electric	2024 Gas	2025 Electric	2025 Gas
1 Revenue Deficiency - Grossed Up	$ 330.0	$ 165.5	$ 62.7	$ 29.9	$ 10.2	$ 23.3
2 Changes To Other Price Schedules	(19.5)	(22.5)	0.4	(1.4)	21.6	(0.0)
3 Total Revenue Change	$ 310.6	$ 143.0	$ 63.1	$ 28.5	$ 31.8	$ 23.3

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

A. As explained by Mr. Jhaveri in Exh. BDJ-1T, PSE's current rate structure is recovering its base revenue in multiple rate schedules. The following provides a summary:

- Base Rates – 2019 general rate case (Dockets UE-190529 and UG-190530) including rates effective from Order No. 14;
- Schedule 95 monthly rate[68] – 2020 power cost only rate case (Docket UE-200980);
- Schedule 149 – natural gas cost recovery mechanism (Docket UG-210678); and
- Schedule 139 – Voluntary Long Term Renewable Energy Purchase Rider ("Green Direct").

Because PSE's base revenues are being recovered in multiple rate schedules, the requested net revenue change that will result from this general rate case for electric and natural gas will be achieved by changing all of the base and adjusting rate schedules listed above. In its direct filing, PSE has not filed changes to the tariffs for all of the rate schedules listed below; rather, as discussed by Mr.

[68] The supplemental rate under Schedule 95 is recovering prior PCA deferral balances and as such, will not be affected by this general rate case.

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

- Base rates will be changed to reflect the revenue requirement authorized in this proceeding that is not subject to refund;
- Schedule 95 monthly rate will be set to zero;
- Schedule 149 will be set to zero;
- Schedule 139 – Voluntary Long Term Renewable Energy Purchase Rider will be changed to reflect the amount approved in this proceeding;
- Schedule 141C – Colstrip Adjustment Rider is a newly proposed tariff schedule to recover the costs of the Colstrip generation facility that is discussed in more detail later in my testimony;
- Schedule 141N – the schedules are the new tariffs that will be utilized to set rates that will change during the multiyear rate plan period and that are not subject to refund; and
- Schedules 141R – the schedules are the new tariffs that will be utilized to set rates subject to refund.

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

A. No. My testimony will focus only on determining PSE's base rates revenue requirement. I will discuss the amount that base rates are deficient (as shown on line 1 in Table 7) based on this revenue requirement.

Q. How will the fact that there are three distinct rate periods impact the tariffs for which PSE is requesting approval?

A. PSE has submitted three separate sets of tariff sheets for certain of the above tariffs to align with the three distinct rate periods.

VI. REVENUE REQUIREMENTS

Q. Please explain how this filing was prepared.

A. Per WAC 480-07-510, PSE must provide a detailed portrayal of the restating and pro forma adjustments in its testimony and exhibits. In order to discuss the restating adjustments independent of the pro forma adjustments, PSE has set up each of its adjustments to show the restating adjustments separately from the pro forma adjustments, as the restating adjustments are the basis upon which pro forma adjustments must be calculated per WAC 480-07-510. Additionally, as discussed above, this case proposes a three-year multiyear rate plan. Therefore, there are pro forma and provisional pro forma adjustments needed to present the rate base in service at the start of the rate effective period, consistent with the requirements of the MYRP Statute, as well as for years one, two and three of the multiyear rate plan. Accordingly, PSE used the following steps to determine the revenue requirement for this proceeding:

1. **Test Year Results of Operation** – PSE started with the test year results of operations for the twelve months ended June 30, 2021, as presented in Exh. SJK-3, prepared by PSE witness Stephen J. King. The test year rate base is included in Exh. SEF-5 for electric operations and Exh. SEF-10 for natural gas. Consistent with prior general rate cases, PSE's rate base was developed

using the historical AMA of the balances for the 13 months ended June 30, 2021. As is discussed later in my testimony, through a restating adjustment, the average net plant in service balances were adjusted to the end of period ("EOP") balances as of June 30, 2021.

2. **Restating Adjustments** – PSE prepared restating adjustments to adjust the test year operating results to reflect the results on a basis the Commission accepts for determining rates. The restating adjustments are necessary to annualize ongoing costs and revenues that PSE began to incur and realize part way through the test year and to adjust the balances to normalized levels consistent with historical ratemaking practices.

3. **Pro Forma Adjustments** – The sum of values resulting from Steps 1 and 2 reflect the restated results of operations upon which pro forma adjustments must be based. Among its traditional pro forma adjustments, PSE has included: adjustments to reflect all plant additions that will be placed in service by December 31, 2021; and adjustments to make other known and measurable changes as discussed in more detail below

4. **Provisional Pro forma Adjustments** – These adjustments, some of which are provisional and subject to the review process and potential refund as outlined earlier in my testimony, are necessary to a) reflect the fair value of plant at the start of the rate year, December 31, 2022, consistent with the MYRP Statute and b) reflect projects that will be placed in service during each year of the multiyear rate plan. These adjustments also take into consideration the revenue and O&M and offsetting factors expected for the same periods.

A. Exhs. SEF-3 and SEF- 8 Net Revenue Change Requested

Q. Would you please explain Exhs. SEF-3 and SEF-8?

A. Exh. SEF-3 presents the calculation of the electric revenue change requested based on the restated, pro forma, and provisional adjustments for each year of the multiyear rate plan. It also presents the pro forma cost of capital for the test year and each of the rate years and the electric conversion factor.

Exh. SEF-8 presents the calculation of the natural gas base revenue change requested based on the restated, pro forma, and provisional adjustments for each year of the multiyear rate plan. It also presents the pro forma cost of capital for the test year and each of the rate years, and the natural gas conversion factor.

The following are descriptions of the individual pages in Exh. SEF-3 and Exh. SEF-8.

<u>Electric Net Revenue Change Requested</u>

The electric net revenue change requested for each year of the multiyear rate plan period is shown on page one of Exh. SEF-3. The schedule shows the rate base, line 12; requested rate of return, line 13; operating income requirement, line 15; pro forma operating income, line 17; and operating income deficiency, line 18. The requested revenue change before other price schedule changes, line 21, for each year of the multiyear rate plan are also presented. The incremental net revenue change is presented on line 23. After the expected reduction to other price schedules, supported by Mr. Jhaveri on line 33 for electric[69] and line 28 for natural gas, the incremental net revenue change for each year of the multiyear rate plan is presented on line 35.

<u>Electric Rate Year One - 2023</u>

Based on $5.7 billion invested in rate base, a 7.39 percent rate of return and $169.9 million of pro forma operating income, PSE requires a revenue change for electric of $330.0 million for year one of the rate plan. After the expected

[69] I also provide support for the change to Schedule 141C in Exh. SEF-18.

reduction to other price schedules of $19.5 million, the net revenue change requested, presented on line 35, is $310.6 million. This represents the requested net revenue change in year one and contains amounts associated with the value of property in service as of the first rate effective period on an end of period basis as well as the value of property placed in service during the first rate effective period on an AMA basis.[70] I present and explain additional exhibits later in my testimony that will delineate these amounts. Additionally, I discuss later in my testimony how the requested rate change is assigned to each of the tariff schedules that will be used for setting rates for each year of the multiyear rate plan.

Electric Rate Year Two – 2024

Based on $6.0 billion invested in rate base, a 7.44 percent rate of return and $153.1 million of pro forma operating income, PSE requires a revenue change for electric base rates of $392.7 million for year two of the rate plan. This represents an additional $62.7 million over the requested revenue change from rate year one. After the expected increase to Schedule 141C and the impact of load changes of $0.4 million, the net revenue change requested, presented on line 35, is $63.1 million.

Electric Rate Year Three – 2025

Based on $6.4 billion invested in rate base, a 7.49 percent rate of return and $179.3 million of pro forma operating income, PSE requires a revenue change for

[70] Used and Useful Policy Statement, ¶ 36.

electric base rates of $402.9 million for year three of the rate plan. This represents an additional $10.2 million over the requested revenue change from rate years one and two. After the expected increase to Schedule 141C and the impact of load changes of $21.6 million, the net revenue change requested, presented on line 352, is $31.8 million.

Natural Gas Net Revenue Change Requested

The gas net revenue change requested for each year of the multiyear rate plan period is shown on page one of Exh. SEF-8. This page shows the test period rate base, line 12; requested rate of return, line 13; operating income requirement, line 15; pro forma operating income, line 17; and operating income deficiency, line 18. The revenue changes before other price schedule changes, line 21, for each year of the multiyear rate plan are also presented. The incremental net revenue change is presented on line 23. After the expected reduction to other price schedules on line 28, supported in the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-1T, the incremental net revenue change for each year of the multiyear rate plan is presented on line 30.

Natural Gas Rate Year One - 2023

Based on $2.96 billion invested in rate base, a 7.39 percent rate of return, and $94.1 million of pro forma operating income, PSE requires a net revenue change for natural gas revenues of $165.5 million for year one of the multiyear rate plan. After the expected reduction to other price schedules of $22.5 million, PSE's net revenue change requested for natural gas shown on line 28 is $142.99 million. This represents the requested net revenue change in year one and contains amounts associated with the value of property in service as of the first rate effective period on an end of period basis as well as the value of property placed in service during the first rate effective period on an AMA basis. I present and explain additional exhibits later in my testimony that will delineate these amounts. Additionally, I discuss later in my testimony how the requested rate change is assigned to each of the tariff schedules that will be used for setting rates for each year of the multiyear rate plan.

Natural Gas Rate Year Two – 2024

Based on $3.1 billion invested in rate base, a 7.44 percent rate of return and $85.6 million of pro forma operating income, PSE requires a revenue change for natural gas of $195.4 million for year two of the rate plan. After taking the impacts of the change in load from 2023, of $1.4 million, this represents an additional $28.5 million over the requested revenue change from rate year one.

Natural Gas Rate Year Three – 2025

Based on $3.2 billion invested in rate base, a 7.49 percent rate of return and $76.6 million of pro forma operating income, PSE requires a revenue change for natural gas of $218.7 million for year three of the rate plan. After taking the impacts of the change in load from 2023, of $0.01 million, this represents an additional $23.3 million over the requested revenue change from rate years one and two.

Q. How will the requested revenue changes be assigned to the various tariff schedules that will be used for setting rates for each year of the multiyear rate plan?

A. The assignment of the requested revenue change to the various schedules is presented on page one of Exhs. SEF-4 and SEF-9. The incremental net revenue changes before changes to other price schedules discussed above are shown on line 71. As discussed above in Section II. B, these requested rate changes will be assigned to base rates, Schedule 141N and Schedule 141R.

Q. How much of the requested revenue changes will be assigned to base rates?

A. The amount assigned to base rates is the portion of the deficiency associated with the traditional pro forma period that ends December 2021 (column g line 65). For electric operations, this amount is a surplus[71] of $13.0 million and for natural gas operations, this amount is a $62.5 million deficiency.[72] PSE proposes that base rates will remain unchanged during the multiyear rate plan.

Q. How much of the requested revenue changes will be assigned to 141R?

A. Schedule 141R is the rate schedule that PSE is proposing be subject to refund. The calculation of the amount of the incremental deficiencies to be assigned to

[71] The amount for electric is a surplus due to the revenue requirement rate base and operation expenses for Colstrip being included in Schedule 141C as discussed in more detail in Exh. SEF-18.

[72] The overall net revenue changes agree between Exhs. SEF-4 and SEF-9 and Exhs. BDJ-7 and JDT-6. However, the component amounts reflected in Exhs. BDJ-7 and JDT-6 will differ from amounts reported in this section by the impacts of load changes.

Schedule 141R is presented in Exh. SEF-23 for electric and SEF-24 for natural gas. As discussed above, the amount assigned to base rates is the portion of the deficiency associated with utility plant and depreciation expense on investments made after December 2021. The deficiencies assigned to Schedule 141R for electric are $102.1 million in 2023, $118.1 million for 2024 and $114.3 million for 2025 (line 75 columns k, m and o). The amounts assigned to Schedule 141R for natural gas are $81.2 million in 2023, $53.7 million for 2024 and $39.9 million for 2025 (line 75 columns k, m and o).

Q. How much of the requested revenue changes will be assigned to 141N?

A. Schedule 141N is the rate schedule that PSE is proposing that will not be subject to refund and that is being utilized in order to not have to change base rates during the multiyear rate plan. As noted above, PSE is proposing that Schedule 141N include the rates associated with the recovery of costs not subject to refund, which include all other costs not included in base rates and Schedule 141R. The amounts assigned to Schedule 141N for electric are $240.95 million in 2023, negative $55.5 million for 2024 and negative $104.1 million for 2025 (line 74 columns k, m and o) in Exh. SEF-4, p.1. The amounts assigned to Schedule 141N for natural gas are $81.2 million in 2023, $53.7 million for 2024 and $39.9 million for 2025 (line 74 columns k, m and o). Of note is that Schedules 141N present surpluses in the last two years of the rate plan due to the benefit of the ongoing decrease in existing plant and depreciation as the revenue requirement associated with all provisional pro forma plant additions is included in Schedule 141R. As discussed in Section II. B above, once each year's annual review is complete amounts for the prior year's Schedule 141R will be transferred to Schedule 141N, which, depending on the amount of the transfer, would provide for a surcharge in rates in Schedule 141N. Such transfer is not reflected on Exhs. SEF-4 and SEF-9.

Q. Please further explain how Exhs. SEF-23 and SEF-24 were prepared.

A. PSE utilized the same process for calculating the rate base impacts from test year retirements and forecasted plant additions and applied the process to plant additions and retirements that are estimated to occur after 2021.[73]

The impacts on accumulated EDIT and EDIT reversals for the forecasted retirements were incorporated into the calculations for Exhs. SEF-23 and SEF-24 as well.

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

The requested revenue changes for the multiyear rate plan is presented in Table 7 above. As discussed by multiple witnesses in this filing, the need for the revenue change primarily results from increased power costs and investment in clean energy transformation, safety, reliability and technology infrastructure. Table 8 below provides an overview of the drivers of the net revenue change requested in this proceeding.

[73] Mr. Marcelia provides a detailed description of the process used in Exh. MRM-1T and MRM-3.

Table 8. Causes of Requested Revenue Changes

DESCRIPTION	2023 ELECTRIC	2023 GAS	2023 COMBINED	2024 ELECTRIC	2024 GAS	2024 COMBINED	2025 ELECTRIC	2025 GAS	2025 COMBINED
RATE BASE	$ 58.8	$ 87.9	$ 146.7	$ 40.3	$ 18.7	$ 59.0	$ 45.2	$ 11.4	$ 56.6
POWER COSTS	125.5	-	125.5	11.1	-	11.1	(63.4)	-	(63.4)
OPERATING EXPENSES	7.9	13.9	21.8	2.3	2.5	4.8	7.3	3.3	10.6
CUSTOMER AND A&G	77.0	17.4	94.4	10.3	3.5	13.8	11.0	2.3	13.3
PLANT DEPRECIATION / AMORTIZATION	(18.8)	44.6	25.8	27.0	12.9	39.9	30.2	11.4	41.6
REGULATORY AMORTIZATIONS	26.1	9.4	35.4	(6.2)	(2.7)	(8.8)	(8.3)	(3.6)	(11.9)
REVENUE (GROWTH) DECLINE	30.7	(20.3)	10.4	(19.7)	(4.1)	(23.8)	(4.7)	(0.9)	(5.5)
OTHER	23.0	12.5	35.5	(2.5)	(1.0)	(3.4)	(7.0)	(0.7)	(7.7)
REVENUE DEFICIENCY - GROSSED UP	**$ 330.0**	**$ 165.5**	**$ 495.5**	**$ 62.7**	**$ 29.9**	**$ 92.6**	**$ 10.2**	**$ 23.3**	**$ 33.5**
COLSTRIP COSTS TRANSFERRED TO TRACKER	53.9		53.9	3.6		3.6	22.4		22.4
REDUCTIONS FOR PCORC, GD, CRM AND LOAD	(73.3)	(22.5)	(95.8)	(3.2)	(1.4)	(4.6)	(0.8)	(0.0)	(0.8)
TOTAL REVENUE CHANGE	**$ 310.6**	**$ 143.0**	**$ 453.6**	**$ 63.1**	**$ 28.5**	**$ 91.6**	**$ 31.8**	**$ 23.3**	**$ 55.1**
PERCENTAGE INCREASE	13.59%	12.98%	13.40%	2.47%	2.29%	2.41%	1.22%	1.83%	1.42%

Cost of Capital for Electric and Natural Gas

Page two of both Exh. SEF-3 and Exh. SEF-8 reflect the proposed capital structure for PSE during the rate year and the associated costs for each capital category. The capital structure and costs are presented by PSE witness Cara G. Peterman. The requested rate of return is 7.39 percent and 6.86 percent net of tax for the first rate year. It is 7.44 percent and 6.91 percent net of tax for the second rate year, and 7.49 percent and 6.96 percent net of tax for the third rate year. Ms. Peterman supports the requested capital structure and components of the cost of debt for each year of the multiyear rate plan. Please also see the Prefiled Direct Testimony of Ann E. Bulkley, Exh. AEB-1T, for support for the requested return on equity of 9.90 percent. Mr. Marcelia discusses the ramifications that would be experienced if additional tax reform is passed. In the event that the statutory tax rate is changed, the net of tax rate of returns presented on this exhibit would also change.

Electric and Natural Gas Conversion Factors

Page three of both Exh. SEF-3 and Exh. SEF-8 provide the electric and natural gas conversion factors that are used to adjust the electric and natural gas net operating income deficiency for revenue sensitive items and federal income tax to determine the total electric and natural gas requested net revenue change. The revenue sensitive items are the Washington State utility tax, Washington Utilities and Transportation Commission ("WUTC" or "Commission") annual filing fee, and bad debts. These conversion factors are 0.752355 for electric operations and 0.754801 for natural gas operations. These amounts are used for all years within the multiyear rate plan. Similar to the net of tax rates of return, should Congress pass legislation changing the statutory corporate tax rate, the conversion factors would need to be changed accordingly.

Q. Are there other potential changes that could occur the conversion factors during this proceeding?

A. Yes. Senate Bill 5634[74] seeks to increase the WUTC filing fee to twice its current amount. PSE currently pays roughly $4.5 million for electric and $2.0 million for natural gas for utility filing fees. Should the bill be ratified, PSE would need to update its revenue requirement to adjust for the higher level of fees and to update its conversion factors.

[74] https://app.leg.wa.gov/billsummary?BillNumber=5634&Year=2021&Initiative=False.

B. Exhs. SEF-4 & SEF 9--Electric and Natural Gas Summary

Q. Would you please explain both Exh. SEF-4 and Exh. SEF-9?

A. Exh. SEF-4 and Exh. SEF-9 present an overview of the income statement and rate base starting with the unadjusted test year through the adjusted results of operations for each year of the three years in the multiyear rate plan for electric operations, (Exh. SEF-4) and natural gas operations (Exh. SEF-9).

The first page of Exhs. SEF-4 and SEF-9 presents the impact of each of the respective electric and natural gas aggregated adjustments by period being made to the June 30, 2021 operating income statement and rate base.

- Column c presents the unadjusted operating income statement and the AMA rate base for PSE as of June 30, 2021 (the test year) and is labeled actual results of operations. As stated above, the income statement amounts are supported by Mr. King. The rate base amounts are provided in Exh. SEF-5.
- Column d presents the total restating adjustments.
- Column e is the sum of columns c and d (actual results of operations plus restating adjustments) and this total is referred to as the restated results of operations.
- Column f presents the adjustments made for the traditional pro forma period, through December 31, 2021, which is six months after the end of the test year.
- Column g is the sum of columns e and f (restated results of operations plus pro forma adjustments) and is referred to as the December 2021 adjusted results of operations.
- Column h presents the 2022 Gap Year Provisional Adjustments. These adjustments are necessary to reflect PSE’s costs at the start of the rate year. These adjustments are reflected on an end of period basis to allow for measurement of the fair value of plant at the start of the rate year.

- Column i presents the adjusted results at the start of rate year one. It is calculated by adding the provisional adjustments from column h to the December 2021 adjusted results of operations (column g) and is consistent with the requirements of the MYRP statute discussed earlier in my testimony.

- Column j presents the rate year one provisional adjustments. These adjustments are necessary to reflect the costs that will occur during the rate year and are presented on an average of monthly average basis.

- Column k presents the adjusted results of operations for the rate year one period. These amounts are used to calculate the initial revenue change that is requested in this filing for year one, as shown in Exh. SEF 3 and Exh. SEF 8. Lines 65 and 71 of these exhibits present the cumulative and incremental changes to the net revenue change requested. The amounts reflected in column i represent the portion of the amounts in column k that relate to the valuation of property as of the first rate effective period, or December 31, 2022.

- Column l presents rate year two provisional adjustments. These adjustments are necessary to reflect the costs that will occur during the second year of the rate plan and are presented on an average of monthly average basis.

- Column m presents the adjusted results of operations for the rate year two period. These amounts are used to calculate the revenue change that is requested in this filing for year two as shown in Exh. SEF 3 and Exh. SEF 8.

- Column n presents rate year three provisional adjustments. These adjustments are necessary to reflect the costs that will occur during the third year of the rate plan and are presented on an average of monthly average basis.

- Column o presents the adjusted results of operations for the rate year three period. These amounts are used to calculate the revenue change that is requested in this filing for year three, as shown in Exh. SEF 3 and Exh. SEF 8.

Pages two through nine of Exh. SEF-4 and pages two through five of Exh. SEF-9 present a detailed summary schedule for all the respective electric or natural gas adjustments that support the summary on page one of these exhibits. Each detailed summary provides the amounts for each of the adjustments within each period and are categorized into the same time periods as shown on the first page of these exhibits.

C. Exhs. SEF-5 and SEF-10, Electric and Natural Gas Test Year Data

Q. Would you please explain both Exh. SEF-5 and Exh. SEF-10?

A. Exhs. SEF-5 and SEF-10 present the respective electric and natural gas test year rate base, working capital, and allocation methods.

Rate Base

Pages one and two of Exh. SEF-5 and page one of Exh. SEF-10 present the test year AMA and EOP rate base calculation for electric and natural gas, respectively. The test year rate base and working capital presented for the test year in this proceeding are reported on an AMA basis, consistent with the Commission's traditional approach to ratemaking. I discuss in more detail later in my testimony the adjustment that is made to reflect PSE's rate base and working capital on an end of period basis.

Investor Supplied Working Capital

Page three of Exh. SEF-5 and page two of Exh. SEF-10 present the test year working capital calculation for electric and natural gas, respectively, that are included as part of the respective rate base calculations. Due to the difficulty and impracticality in forecasting an investor supplied working capital calculation, PSE uses the restated value for each of the rate years.

Allocation Factors

Page four of Exh. SEF-5 and page three of Exh. SEF-10 present the allocation methods and factors used in allocating common expenditures between electric and natural gas operations. Common utility plant is that portion of utility operating plant that is used for providing more than one commodity to customers, i.e., both electricity and natural gas service. Common plant includes costs associated with land, structures, and equipment, which are not charged specifically to electric or natural gas operations. PSE allocates its common utility plant for electric and natural gas by using the four-factor allocation method.

Common operating costs are those costs that are incurred on behalf of both electric and natural gas customers. PSE incurs common costs related to customer accounts expenses, customer service expenses, administrative and general expense, depreciation/amortization, other operating expenses, and taxes other than federal income tax. These common costs are allocated to electric and natural gas using the most appropriate allocation method for the type of cost being allocated. Allocation methods used include (1) twelve-month customer average, (2) joint meter reading customers, (3) non-production plant, (4) four-factor allocator, and (5) direct labor allocator. An allocation factor that can be used in assigning total costs between operating costs, capital and non-utility when warranted is also presented on this exhibit.

VII. INDIVIDUAL ADJUSTMENTS

Q. Please explain the organization of the individual adjustments.

A. Each of the individual adjustments can be restating, pro forma (traditional or provisional), or both restating and pro forma. Exh. SEF-6 contains adjustments that pertain to electric service, and Exh. SEF-11 contains adjustments that pertain to natural gas operations. Exh. SEF-13 provides the impacts of each adjustment on net operating income, rate base (page 1) and the related revenue requirement (page 2). The dollar value of the impact on rate base and net operating income is not presented in my testimony for each adjustment in order to streamline the testimony. Therefore, Exh. SEF-13 is being provided for reference when reading the description of each adjustment below. Exh. SEF-14 provides an overview of all the revenue requirement adjustments being made and identifies whether the adjustment is electric only or natural gas only or common, and if it has a restating, pro forma and provisional pro forma component.[75]

[75] Exh. SEF-14 is very useful as a reference tool while reading this testimony. The adjustment descriptions reference numerous adjustment numbers. The adjustments are not numbered strictly in numerical order, which provides for the flexibility to include additional adjustments that may be identified or proposed by other parties.

A. Common Adjustments

Q. Please provide an explanation of the common adjustments included in Exhs. SEF-6 and SEF-11.

A. The common adjustments are those that apply to both electric and natural gas operations and are contained in SEF-6 for electric operations and in SEF-11 for natural gas operations. An explanation of each of the proposed common adjustments is presented below:

1. Adjustment Nos. 6.01 and 11.01 - Revenues and Expenses

The restating adjustments included in this adjustment for electric and natural gas are those that are typically made in a CBR. Additional restating adjustments are included for required annualizing adjustments that are not allowed in a CBR. The adjustments to electric sales to customers are supported by Mr. Jhaveri. The adjustments to natural gas are supported or discussed by Mr. John D. Taylor. A discussion of the electric and natural gas adjustments by type of adjustment is as follows:

- For electric only, lines 17 and 53, a restating adjustment is made to remove the credits passed back to customers and the related amortization associated with Schedule 95A Federal Incentive Tracker. The tax impacts associated with the Schedule 95A revenue and amortization are removed in the federal income tax adjustment, which is Adjustment 6.04;
- For electric only, a restating adjustment is made to reclassify electric transportation revenues in Other Operating Revenues (line 41) to Sales to Customers (line 26) to support the electric cost of service process;
- For both electric (lines 21 and 23) and natural gas (lines 18, 20, 33 and 35), a restating adjustment is made to remove the credits passed back to customers

during the test year for the amortization of protected and unprotected EDIT in rate schedules 141X and 141Z. The amortization and tax impacts associated with these revenues are removed in the federal income tax adjustment, which is restating adjustment 6.04;

- For both electric (lines 22 and 40) and natural gas (lines 19, 34 and 40), a restating adjustment is made to remove the credits and related amortization for the amounts passed back to customers during the test year for the interim period tax amounts over-collected from January through April 2018 that were passed back in Schedule 141Y;

- For both electric (lines 24 and 25) and natural gas (lines 21 and 22), a restating adjustment is made to annualize rates from PSE's 2019 general rate case, including the original compliance filing from October 2020 as well as the update for Order 14 which became effective after the test year ended in October 2021. The adjustment for October 2021 is included as a restating adjustment (as opposed to a pro forma adjustment) because PSE had an accounting petition in effect during the test year which accrued for the adjustment that was allowed for in Order 14. The removal of this accrual is shown on line 42 for both electric natural gas;

- For both electric (line 20) and natural gas (lines 17 and 32), a restating adjustment is made to remove the revenues from Schedule 141, which recovered PSE's Expedited Rate Filing in UE-180899 and UG-180900 that were replaced by the revenues from PSE's 2019 general rate case discussed in the previous bullet;

- For both electric (line 44) and natural gas (line 37), a restating adjustment is made to remove the GAAP[76] reserve on the entries to defer reconnection and late fee revenue discussed in Section III above;

- For gas only, the restating adjustments on lines 44 and 52 relate to the removal of inter-book storage revenues and gas costs from Jackson Prairie. These adjustments are associated with the removal of PSE's Schedule 101 revenues and gas costs that are removed in the pass-through restating adjustment 6.02. (lines 20, 21, 41 and 42);

- For electric only, line 28 adjusts the amount of unbilled revenue recognized in the test year for the actual test year billing determinants; and

- Finally, certain other adjustments that are not specifically identified result from the process conducted by cost of service of reconciling the test year and pro forma results that are determined based on applying the most current base

[76] Generally Accepted Accounting Principles.

rates to the normalized pro forma billing determinants. These amounts are reflected on lines 30 and 31for electric and line 24 for natural gas.

Pro Forma Adjustments:

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

- For electric and natural gas, modifies the test year revenues to the revenues that would have been collected during the test year if only the base rates from the 2019 general rate case and 2020 power cost only rate case[77] had been in effect for the entire test year. The annualization of base rates revenue was discussed in the restating section above. Also, as discussed in Section V, my testimony focuses on determining and describing only the change in the revenue requirement related to base rates. Messrs. Jhaveri and Taylor cover the change to the other rate schedules, which include Schedule 95 Power Cost Adjustment Clause, Schedule 139 Voluntary Long Term Renewable Energy Purchase Rider ("Schedule 139"), Schedule 149 Cost Recovery Mechanism for Pipeline Replacement, and Schedule 141C Colstrip Tracker. For purposes of determining the revenue requirement, the following steps were taken to reflect the revenue in the test year at 2019 general rate case and 2020 power cost only rate case levels:

    - This adjustment removes the decoupling deferrals and amortization, including the associated twenty-four month GAAP reserve (line 43 for electric only), to reflect the test year revenue on a volumetric basis (lines 39 for both electric and natural gas); and

    - The above step results in the test year revenue being reflected on a volumetric basis priced at 2019 general rate case and 2020 power cost only base rates. Therefore, the final step is to weather normalize these revenues, which is performed in Adjustments 6.03 and 11.03 and discussed further below in my testimony.

- Line 27 for electric represents the migration of Schedule 40 customers. Schedule 40 no longer exists and this adjustment is for the final migration to other schedules, with most locations taking service under Schedule 26;

[77] For the 2019 general rate case, rates were effective on October 15, 2020 and October 1, 2021 for electric. For natural gas, rates were effective on October 1, 2020 and October 1, 2021. For the 2020 power cost only rate case, rates were effective July 1, 2021.

- For natural gas only, line 23 removes the revenues from Schedule 149, Gas CRM. PSE is requesting recovery of its gas CRM investment in the multiyear rate plan, and if approved, will no longer use Schedule 149 for recovery of this program investment. Accordingly, these revenues are being set to zero;

- For natural gas only, line 38 removes the revenues associated with the gas rental service under Schedules 71 and 72 as this service was discontinued on December 22, 2020;

- For natural gas only, lines 41 and 51 remove revenues and gas costs associated with curtailment and entitlement charges associated with PSE's Purchased Gas Adjustment; and

- For electric only, lines 18, 19, and 45 remove the revenues and amortizations associated with Schedule 139 as prior Commission orders and statute require that there be no cross-subsidization resulting from this program. Additional costs and rate base for the program are removed in adjustment 6.50.

Adjustments to the Gap Year and Rate Years:

- Line 29 for electric and line 26 for natural gas provide an adjustment to the increase or decrease in revenue at current rates for the forecasted changes in rate year billing determinants. These adjustments are calculated by Mr. Jhaveri for electric and Mr. Taylor for natural gas. I discuss in more detail below the causes in the variations in the forecasted billing determinants;

- Included in Electric Other Operating Revenue on line 46 is a forecast for the Washington paths and the Southern Intertie retail wheeling, network and ancillary services provided by PSE. Production related transmission revenues are included in the PCA mechanism and are not included in this adjustment. The increase in Other Operating Revenue from the test year to the first rate year in 2023 stems primarily from BPA customer revenue forecasts and is due to a combination of both increased load forecasts between 2020 and 2022 and the increased formula rate in 2021. PSE uses load forecasts provided by BPA and these reflect a cumulative increase between 2020 and 2022 of approximately 52 percent. The load forecast increase remains relatively flat between 2022 through 2025. The network and retail wheeling transmission Formula Rate increased by 33 percent in 2021. A three percent escalation to the rate was applied from 2022 through the end of the third rate year in 2025. For natural gas only, line 25 pro forms in transportation revenues associated with Puget LNG. This adjustment is supported by Mr. Taylor;

- For electric only, lines 35 through 37 provide a forecast of the additional program revenues that are forecasted for the rate years. These forecasted revenues are discussed in the Prefiled Direct Testimony of Mr. William T. Einstein, Exh. WTE-1T. The associated test year and forecasted utility plant and O&M are included in Adjustments 6.22 and 6.29 through 6.31; and

- For electric only, line 38 recognizes the rate year level of the Schedule 139 resource option energy charge net of the energy charge credit that is proposed to be provided to Schedule 139 customers which will result in a decrease to revenues that offset the calculated revenue requirement.

Q. Related to the first adjustment discussed under the Gap Year and Rate Year adjustments above, please explain what PSE has observed and is forecasting related to customer electric load.

A. PSE's overall system electric load is forecasted to be lower for the gap year (2022) and beyond than loads observed in the test year. The most significant decline in electric load is observed in the gap year, with a modest increase in 2023-2024, and load in 2025 grows only slightly from 2024 levels.

Q. What is the reason for lower electric loads?

A. According to PSE's officially approved forecast, for the current case, loads are projected to be lower for the rate years than loads for the test year. This is primarily due to the assumptions regarding the economic and policy impacts of the COVID-19 pandemic as well as the added effects of realized energy savings due to demand-side resources ("DSR").

Q. What are PSE's assumptions regarding the economy?

A. Generally speaking, economic assumptions included in the load forecast are that the economic downturn is greatest in 2020 and recovers from 2021 to 2024. These assumptions are based on the April 2021 Moody's Analytics economic outlook (the time at which the forecast was developed). Beyond traditional economic assumptions like unemployment, policies enacted to slow the spread of COVID-19 such as employers having their employees work remotely from home and students attending online classes from home also affect loads. Together, the impacts of the economic downturn and COVID-19 policies are disproportionate among customer classes. While the non-residential class loads have been lower than pre-pandemic levels and are forecasted to stay lower, the observed residential electric loads have been higher. However, by 2022, the forecast assumes residential electric loads will revert back to 2019 pre-pandemic levels as employees return to the office and students return to in-person school.

Q. How do demand-side resources affect the observed and forecasted loads?

A. Demand-side resources, primarily comprised of PSE energy efficiency programs as well as state and federal building codes and equipment standards, lower the amount of energy consumption that would have taken place otherwise. In recent years, residential electric use per customer has remained flat or has declined due to the amount of DSR implemented. Commercial electric use per customer has also been declining in recent years due to DSR. Estimated amounts of DSR for the rate years 2023-2025 keep the amount of total residential load essentially flat and drive a decline in total commercial load.

Q. What is the net effect of these impacts and assumptions on PSE's electric load?

A. By 2022, forecasted electric residential use per customer reverts back down to pre-pandemic levels, continuing the pre-pandemic trend in declining use per customer due to DSR. Non-residential use per customer does not rebound to pre-COVID levels, and DSR continues to accumulate and further decrease energy consumption. These assumptions drive the overall decline in energy consumption for PSE's system in 2022 compared to the test year. For years 2023–2024, modest growth in electric system load is expected due to the rebound in the economy. Additional amounts of DSR keep energy consumption essentially flat in 2025 compared to 2024.

Q. Do natural gas loads follow the same growth pattern as the electric?

A. While there are some similarities regarding the observed and forecasted load growth for natural gas and the electric loads, there are also some differences. PSE's natural gas system load is forecasted to grow slightly in 2022 compared to the test year, remain flat for 2023, grow modestly in 2024, and then decline in 2025.

Q. Please describe the impacts of the economic downturn and other pandemic policies on natural gas consumption.

A. The economic downturn starting in 2020 and continuing through mid-2021 caused a decline in the non-residential natural gas loads as it did with non-residential electric customers. However, unlike residential electric, residential natural gas consumption declined even though many people were staying home to work and attend school online.

Q. What are the assumptions for natural gas loads and how they respond to the economic recovery taking place starting in 2021?

A. During the second half of 2021, the forecast assumes the economy starts to recover with total employment in 2022 forecasted to be above 2019 levels. With this recovery, by the end of 2022, non-residential natural gas loads are forecasted to be similar to 2019 loads, buoyed by the increase in commercial usage. Starting in 2020, manufacturing employment began to decline and is not projected to recover by 2025. This negatively impacts industrial natural gas load growth from 2020 through 2025. The residential class load growth continues each year starting with the economic recovery in 2021, and it is expected to increase growing each year through 2025 due to population growth.

Q. Does DSR impact natural gas energy consumption like it does electric?

A. Yes, DSR is also implemented to reduce customers' natural gas energy consumption driving use per customer lower. A stronger economy and new customer growth have traditionally offset the decline in average use per customer, but the increase in DSR in 2023 keeps loads flat compared to 2022. The amount of DSR along with the decline in non-residential load due to declining manufacturing employment outweighs growth in the residential and commercial classes, resulting in lower loads in 2025 compared to 2024.

Q. Please continue to describe the revenue requirement adjustments in Exh. SEF-6 and Exh. SEF-11.

A. The next adjustment is Adjustment 6.02, Pass-through Revenue and Expenses.

2. Adjustment No. 6.02, 11.02 - Pass-through Revenue and Expense

This restating adjustment removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as the conservation rider, municipal and property taxes, the low-income rider and the decoupling adjustment mechanism. The associated expenses that are recorded in the test year for these direct pass-through tariffs are also removed in this adjustment.

The green tags purchased as part of the green power program are recorded in Account 557 power costs, and these amounts are removed in the restating adjustment in Adjustment 6.45 Other Power Cost Expenses.

3. Adjustment No. 6.03 and 11.03 - Temperature Normalization

PSE's temperature normalization adjustment to load is supported in the Prefiled Direct Testimony of Kelly H. Xu, Exh. KHX-1T. The pricing of the adjustment to load is supported by Mr. Jhaveri for electric and Mr. Taylor for natural gas. As I discussed above, due to adjustments 6.01 and 11.01, revenues have been reflected on a volumetric basis at 2019 general rate case and 2020 power cost only rate case base rates levels; therefore, the temperature normalization adjustment is necessary to restate and pro form test year delivered load and revenue to a level which would have been expected to occur had the temperatures during the test year been "normal." This adjustment is based on the difference between the actual test year loads. The restating adjustment normalizes all non-decoupled revenues in the test year and is consistent with the methodology used in PSE's CBR. The pro forma adjustment normalizes the remaining revenues that were reflected on a volumetric basis as a result of the adjustment to remove the current decoupling deferrals that was discussed above in adjustment 6.01 and 11.01.

The test year was warmer than normal requiring an adjustment to net operating income to bring revenues up to what would have occurred under normal conditions. The electric temperature load adjustment increases actual load by 2,103 MWhs. The natural gas load adjustment increases actual therms by 34.5

million therms. Ms. Xu discusses PSE's weather normalization methodology, and Mr. Jhaveri and Mr. Taylor support the pricing of the load adjustments and their allocation to the rate classes based on the proposed rate class level weather normalization methodology.

4. Adjustment Nos. 6.04 and 11.04 - Federal Income Tax

The restating adjustment restates the test year for the appropriate level of federal income tax ("FIT") expense for this case before the deduction for interest. On December 22, 2017, the Tax Cuts and Jobs Act ("TCJA") was signed into law. The TCJA resulted in excess deferred income tax assets and liabilities (including both "protected" and "unprotected"). The turn-around of the protected excess deferred taxes during the test year have not been adjusted pursuant to the Internal Revenue Service ("IRS") normalization requirements. This is discussed in more detail by Mr. Marcelia, Exh. MRM-1T. Additionally, as part of this adjustment and pursuant to the Commission's amended final order, Order 14, in the 2019 general rate case, PSE is reflecting the protected-plus EDIT in base rates.[78] The removal of the revenues associated with the pass-back of protected-plus EDIT in Schedule 141X as originally ordered by the Commission in Order 08 in the 2019 general rate case have been removed as discussed in Adjustments 6.01 and 11.01.

This adjustment also includes the removal of the income tax credit associated with the PTC liability; the amortizations of protected-plus and unprotected EDIT that

[78] Paragraph 38 of Order 14 in Docket No. UE-190529 and UG-190530, et al.

were included for pass back to customers in Schedules 141X and 141Z; and the tax impacts associated with Schedule 95A that were removed in Adjustment 6.01 discussed earlier.

To properly reflect federal income tax expense in total, aside from this adjustment, PSE applies the statutory rate of 21 percent to all of its rate making adjustments when appropriate. This method of adjusting total federal income tax expense alone would not adequately adjust FIT for permanent and temporary tax differences such as protected-plus EDIT, the tax benefit of PSE's Hydro Treasury Grant amortizations, and other flow-through items. These items result in PSE's effective tax rate being lower than 21 percent. Additionally, as PSE is filing a multiyear rate plan that projects its utility plant, accumulated depreciation, ADIT, and depreciation expense, PSE's EDIT balances and the EDIT reversal must also be projected in the same manner. Accordingly, within the pro forma, gap year and rate year adjustments, this adjustment handles the modification of those items to their appropriate levels following the IRS normalization rules. The amounts reflected in this adjustment are supported by Mr. Marcelia and represent companion adjustments to amounts included in Adjustment 6.29 Test Year Plant Roll Forward.

5. Adjustment Nos. 6.05 and 11.05 - Tax Benefit of Interest

As in prior general rate cases, PSE has included an adjustment to capture the tax benefit of interest for electric and natural gas operations, which in the test year is all recognized below the line. This adjustment recognizes the tax deduction related to the level of interest associated with rate base in each of the adjustment periods. The restating, pro forma and gap year adjustments are calculated using the rate base for each period and the weighted average cost of debt of 2.62 percent that was realized during the test year as supported by PSE witness Cara G. Peterman and that is shown on page two of Exh. SEF-3 and Exh. SEF-8. The adjustments for each of the rate years are calculated using the rate base and the requested weighted average costs of debt of 2.54 percent for each of the periods that are also shown on page two of both Exh. SEF-3 and Exh. SEF-7. The requested weighted average costs of debt for these periods are also supported by Ms. Peterman.

6. Adjustment Nos. 6.06 and 11.06 - Bad Debt Expense

Consistent with prior cases, this restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years after removing the high and low years. Since it takes four months to write-off a bill, the ratio of the write-off versus revenue is offset by four months. For example, a write-off booked in June is related to revenue that was recognized during the previous February. Using this relationship between June revenues and February write-offs results in the calculation of an appropriate percentage of write-offs associated with revenues in the test year. The bad debt percentage for a given year is calculated by taking the actual write-offs for the year ending in February and dividing them by the net revenues for twelve months ending in June for each of the years. The net test year revenues are multiplied by the calculated average bad debt percentage to determine the amount of restated bad debt expense. This normalized amount is compared to the actual test year level of bad debt expense to determine the effect on income. This bad debt percentage is also used in the conversion factor when determining the final revenue requirement. It is also used for any adjustments that are made to revenues, where appropriate, thus keeping the bad debt expense in line with the revenues included in the relevant periods as well as resulting in only a restating adjustment being required here.

Due to the pandemic and the suspension of disconnection of energy service for non-payment under Docket U-200281, PSE's write-offs over the past several years have been at historical lows, as shown in Table 9 below. Even so, PSE did not change the methodology for calculating normalized bad debt expense as the current methodology of removing the high and low years is intended to accommodate for variations and anomalies in the historical test year bad debt expense. It remains an appropriate method to use under the current historically unique circumstances.

Table 9. Historical Bad Debt Write-Offs

Time Period	Electric		Gas	
12 ME 2/28/2017	$ 16,371,341		$ 4,028,680	
12 ME 2/28/2018	$ 19,105,885	*	$ 4,801,551	*
12 ME 2/28/2019	$ 17,546,987		$ 3,904,619	
12 ME 2/28/2020	$ 12,696,452		$ 3,115,330	
12 ME 2/28/2021	$ 2,853,404	*	$ 1,034,000	*
Restated Amount	$ 15,538,260		$ 3,682,876	

* Removed prior to averaging the remaining three years pursuant to existing methodology

Additionally, should actual write offs eventually exceed the level of bad debt expense PSE has in rates, PSE is able to defer any excess amounts under Dockets UE-200781 and UG-200782. As such, PSE does not propose to change the methodology used to set bad debt expense in rates.

Finally, because PSE uses a specific methodology for recovery of bad debt expense, the total bad debt expense on a regulated basis from this adjustment replaces the level of bad debt expense included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

7. Adjustment Nos. 6.07 and 11.07 - Rate Case Expenses

Consistent with prior rate cases, this restating adjustment uses the average of the last two PCORCs and the last two general rate cases to determine a normalized level of expense. The average cost for a general rate case using this methodology is $2.7 million. This cost is allocated 50 percent to electric and 50 percent to natural gas, which results in a $ 1.3 million average cost for each energy group. The average cost for a power cost only rate case is $0.3 million.

In previous rate cases, the average costs for a general rate case were normalized for recovery over two years and the average costs of a power cost only rate case were normalized over four years. However, because PSE is filing a three-year multiyear rate plan, the normalization period for general rate cases has been lengthened to three years. Additionally, the normalization period for PCORCs has been shortened to two years in recognition of the use of PCORCs in concert with the annual power cost updates being requested in the Prefiled Direct Testimony of Ms. Janet K. Phelps. These normalized periods result in the restating rate case expense totaling $0.6 million for electric and $0.4 million for natural gas. These amounts are then compared to the amount PSE had actually recorded in the test year for each type of rate case expense.

Finally, the forecasted O&M being included in this filing for the rate years does not include a level of expense for rate case expenses. Accordingly, the level of rate case expense from this adjustment is included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

8. Adjustment Nos. 6.08 and 11.08 - Excise Tax

This restating adjustment adjusts the test year to actual expense for the Washington State excise tax that should be recorded for these costs.

9. Adjustment Nos. 6.09 and 11.09 - Employee Insurance

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

The pro forma adjustment adjusts the test year employee benefits expense to the most current average cost per participant based on the test year end of period participant count times the average cost as of September 2021. The forecasted O&M being included in this filing for the rate years does not track employee insurance separately. Accordingly, the level of employee insurance expense from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

10. Adjustment Nos. 6.10 and 11.10 - Injuries and Damages

This restating adjustment restates injuries and damages to the three-year average of accruals and payments. When necessary, amounts are allocated to O&M based on the distribution of wages and then allocated between electric and natural gas based on the average number of customers allocator. Because PSE uses a specific methodology for recovery of injuries and damages, the total amount on a regulated basis from this adjustment replaces the level of injuries and damages expense in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

11. Adjustment Nos. 6.11 and 11.11 - Incentive Pay

Consistent with prior general rate cases, this adjustment, which impacts all periods, uses a four-year average of incentive compensation paid to employees, which is allocated between electric and natural gas operations. Mr. Hunt explains why this expense is appropriate for recovery in rates.

The forecasted O&M in this filing includes a specific level of expense for incentive payments. Because PSE uses a specific methodology for recovery of incentive payments, PSE has replaced the specific amount of incentives in the forecasted O&M with the four-year averaging normalization methodology using the forecasted O&M amounts as indicated on page 2 of Exh. SEF-14. These adjustments are made for all periods after the restating period.

The incentive payment is allocated to O&M based on the distribution of wages. The four-year average of the payouts is allocated between electric and natural gas O&M using the direct labor allocator. For the restating portion of this adjustment, PSE used the payouts that occurred in March for years 2018 through 2021, which related to calendar years 2017 through 2020. For the pro forma period adjustment, the four-year average was updated to include the expected 2022 payout for calendar year 2021 that was discussed above. For each subsequent period, the four-year average was updated to include the forecasted incentive accruals for the 2022 through 2025 periods.

12. Adjustment Nos. 6.12 and 11.12 - Investment Plan

This restating adjustment adjusts the PSE portion of investment plan expense to reflect the annualized expense associated with the wage increases during the test year and is based on the current employee contribution rates.

The forecasted O&M being included in this filing for the rate years does not track investment plan expense separately. Accordingly, the level of investment plan expense from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

13. Adjustment Nos. 6.13 and 11.13 – Interest on Customer Deposits

This restating adjustment annualizes and allows recovery for the interest associated with using customer deposits as a reduction to rate base. Since this interest is originally recorded below the line in the test period, this restated adjustment adds to operating expense the cost of interest for this item based on the most currently implemented annual interest rate. Pursuant to WAC 480-100-113(9) and WAC 480-90-113(9), the interest rate paid on customer deposits is determined annually based on the interest rate for a one-year Treasury Constant Maturity as of the fifteenth day of January of that year. This approach is consistent with prior general rate cases. The forecasted O&M being included in this filing for the rate years does not include a level of expense for interest on customer deposits. Accordingly, the level of interest on customer deposits from this adjustment is included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

14. Adjustment Nos. 6.14 and 11.14 - Property and Liability Insurance

This adjustment is both a restating and pro forma adjustment. The restating adjustment annualizes the most current property and liability insurance premiums, which became effective during the test year. Common property and liability insurance is allocated to electric and natural gas operations based on the non-production plant or number of customers allocation factor.

The pro forma adjustment reflects the known and measurable premium increases for property and liability insurance expense based on premium renewals in April or December 2021. Common property and liability insurance is allocated to electric and natural gas operations based on the non-production plant or number of customers allocation factor.

The forecasted O&M being included in this filing for the rate years does not track property and liability insurance separately. Accordingly, the level of property and liability insurance from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14.

15. Adjustment Nos. 6.15 and 11.15 - Deferred Gains and Losses on Property Sales

The amortization of deferred gains and losses adjustment impacts multiple periods. The restating adjustment is necessary to annualize the amortizations granted in Dockets UE-190529/UG-190530 that are not fully reflected in the test year. The purpose of the pro forma, gap year, and rate year one adjustments is to provide customers the gains and losses from sales of utility real property completed since the last general rate case. The adjustment for natural gas also includes the recovery of the deferred losses on PSE's water heater and conversion burner rental services that have been discontinued. These deferrals were authorized in Dockets UG-190784 and UG-20112. The composition of the deferral balance is supported and discussed by Mr. Einstein. The gains and losses in this adjustment are also allocated between electric and natural gas based on the use of the property and amortized over three years. The adjustments to electric and natural gas in the pro forma and gap year periods recognize that amortizations approved in PSE's 2019 general rate case fully amortize in these periods. The adjustments to rate year one recognize the inclusion of amortization expense for the new deferred gains and losses on property sales. Additionally, for electric, this adjustment removes the large amortization of a deferred gain for the Shuffleton property.

16. Adjustment Nos. 6.16 and 11.16 - Directors and Officers ("D&O") Insurance

The restating adjustment removes the portion of D&O insurance that should be allocated to non-utility activity. This restating adjustment also annualizes the most current premiums, which became effective during the test year for D&O insurance. To allocate the restated insurance expense between utility and non-utility activity, PSE uses an allocation methodology evenly weighted between the 1) allocation of directors' fees and 2) allocation of covered employees' salaries. The total amount is then allocated to O&M expense in the same manner as the test year D&O insurance, which is based on where direct labor is charged. The restated D&O insurance applicable to O&M is then allocated between electric and natural gas operations based on the average number of customers allocator. The forecasted O&M being included in this filing for the rate years does not track D&O insurance separately. Accordingly, the level of D&O insurance from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-14. The level of insurance included in the plan only includes the portion allocable to utility operations.

17. Adjustment Nos. 6.17 and 11.17 - Pension Plan

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

As determined by the plan actuary, PSE made tax deductible cash contributions totaling $54 million for the four-year period ending June 30, 2021. For the restating adjustment, the four-year average of $13.5 million is allocated to O&M based on the distribution of wages, and then allocated between electric and natural gas based on the direct labor allocator.

The forecasted O&M being included in this filing includes pension expense based on a forecast of the expense on a GAAP basis. Because PSE uses a specific methodology for recovery of pension expense, PSE has replaced the specific amount of GAAP basis pension expense in the forecasted O&M with the four-year averaging normalization methodology using the forecasted O&M amount of plan contributions as indicated on page 2 of Exh. SEF-14. The forecasted plan contributions are $18 million per year from 2022 through 2025. The forecasted amounts for each period beyond the restating period are also allocated to O&M based on the distribution of wages and then allocated between electric and natural gas based on the direct labor allocator.

18. Adjustment Nos. 6.18 and 11.18 - Wage Increase

This is a restating adjustment that reflects the impact of wage increases and payroll tax changes, as described by Mr. Hunt. No pro forma adjustment is made as wage expense in the forecasted O&M being included in the rate years is used as the basis of the wage expense for the periods beyond the restating period. Mr. Hunt discusses incremental amounts for union wage increases that have occurred since the test year and are included in the forecasted wages in the board approved

O&M used as the basis for this filing. Accordingly, the level of restated wage expense from this adjustment will be automatically adjusted to the level included in the forecasted O&M as indicated on page two of Exh. SEF-14.

For represented (union) employees, the restating adjustment reflects the known annual wage increases that were granted in the approved contracts for the International Brotherhood of Electrical Workers ("IBEW") and United Association of Plumbers and Pipefitters ("UA") union employees. A contracted wage increase percentage for IBEW union employees of three percent occurred on January 1, 2021. A contracted wage increases for UA union employees of two and three-quarters percent occurred on October 1, 2020.

The average wage increase used in the restating adjustment for non-union employees includes the known wage increase of 3.56 percent that was paid effective March 1, 2021. As in prior rate cases, this increase has been weighted by prior year actual salary increases. This is done to account for "slippage," as it is sometimes called, that occurs when new non-union employees are hired at lower salary rates than the more senior employees they are replacing.

19. Adjustment Nos. 6.19 and 11.19 – AMA to EOP Rate Base

As discussed earlier in my testimony, PSE's test year rate base was developed using historical AMA balances for the 13 months ended June 30, 2021. This restating only adjustment moves the average rate base balances to actual EOP balances as of June 30, 2021. As discussed in Section II.B of my testimony, the new MYRP Statute provides for the valuation of utility property that is used and useful as of the first rate effective period. This end of period adjustment provides the basis on which PSE will forecast its rate base to the end of period amount at December 31, 2022 in conformance with treatment provided for in the MYRP Statute.

20. Adjustment Nos. 6.20 and 11.20 – AMA to EOP Depreciation

The adjustment restates test year depreciation expense as if the end of period balances were in effect for the entire test period. Additionally, this adjustment reduces the annual expense for assets that use the end-of-life convention down to their end-of-period levels. The amortization of these assets is calculated by spreading the gross cost of the assets over a specified life and automatically retiring the asset, thus stopping amortization once the accumulated amortization equals the asset's gross cost.

This adjustment also reclassifies the depreciation on asset retirement costs ("ARC") and asset retirement obligations ("ARO") to depreciation expense. For financial reporting purposes, PSE follows Accounting Standards Codification ("ASC") 410 which governs accounting for AROs. An ARO is a legal obligation associated with the retirement of an asset, where the company is legally responsible for such things as removing equipment or cleaning up hazardous materials at some future date. ASC 410 requires that the ARO be recorded at its discounted net present value and then accreted over time to equal the future value of the remediation. In addition to the ARO, ASC 410 also requires the recognition of an ARC that is depreciated over the life of the asset to which the ARO relates ("underlying asset"). To accomplish this, PSE reclassifies amounts from the net salvage component[79] included in the depreciation of the underlying asset, which is recorded at studied rates in order to recognize its ARO accretion and ARC depreciation. In this adjustment, the reclassification is essentially reversed, which restores the depreciation expense from the ARC depreciation and ARO accretion to the underlying assets. This is necessary to properly compare the depreciation expense on the same basis as the rates as studied in the depreciation study presented in this filing. Mr. Allis provides further discussion of how the requested depreciation rates were developed in light of how PSE accounts for ASC 410.

Notably, PSE is not presenting a separate depreciation study adjustment in this case. As I discussed above as well as later in my testimony, PSE is rolling forward all of its existing test year plant as well as including all of its forecasted plant additions in its request. The new depreciation rates are utilized in calculating the adjustments associated with PSE's proposed treatment of utility plant, and therefore, a separate stand-alone adjustment for the depreciation study is not needed.

In order to transparently provide the impact of the depreciation study, I have provided Exh. SEF-20, which calculates the depreciation expense for 2023 through 2025 without the use of the new depreciation rates and provides the

[79] Mr. Allis defines net salvage in his Prefiled Direct Testimony, Exh. NWA-1T.

difference to the amounts that were determined using the new depreciation rates. Exh. SEF-20 shows that depreciation expense is $32 million higher in total in 2023, with increases of roughly $2 million per year thereafter. The largest increases are seen in Other Production Plant of $12.4 million and Gas Distribution Plant of $18.5 million. Mr. Allis discusses the underlying reasons for the changes in the rates for these classes of assets.

Additionally, to recognize the full impact of the increases in depreciation expense on the EOP accumulated depreciation, PSE increased the balance of accumulated depreciation by the respective increases in depreciation expense. Finally, the change to book depreciation expense necessitates a change to deferred taxes, which are decreased by 21 percent of the change to accumulated depreciation.

21. Adjustment Nos. 6.21 and 11.21 – WUTC Filing Fee

This restating adjustment adjusts the test year WUTC Filing Fee to the level of expense that should have been recorded in the test year for these costs. In order to properly match the level of WUTC Filing Fee to the revenues included in the results of operations for each period, PSE applies the WUTC fee of 0.2 percent to all adjustments made to revenue as appropriate. Accordingly, the level of WUTC Filing Fee included in the forecasted O&M in Adjustments 6.22 and 11.22 is replaced with the WUTC Filing Fee from this and all other adjustments as indicated on page two of Exh. SEF-14. This adjustment would need to be updated if Senate Bill 5634, which was discussed above, is passed.

22. Adjustment Nos. 6.22 and 11.22 – Pro forma O&M

As discussed in Section II.B, the level of O&M PSE is requesting is based on its approved O&M levels in its five-year plan. These amounts are presented by Mr. Kensok. I have taken the approved O&M levels and adjusted them to reflect the approved O&M levels on a Commission Basis. Table 10 below provides an overview of how the approved O&M has been adjusted to be reflected on a Commission Basis. Exh. SEF-17 provides additional details for the adjustments that are reflected in Table 10 and provides the detailed level of support for the total approved plan.

Table 10. Overview of Approved O&M Forecast on a Commission Basis

Description	2023	2024	2025
Total Approved Plan	$752,196,640	$774,803,335	$ 805,280,414
Remove Non GRC and Non O&M Items	(44,777,396)	(47,350,873)	(49,939,690)
Remove Items to be Replaced	(180,999,776)	(182,996,382)	(191,901,557)
Add Back Items on a Regulatory Basis	147,265,058	147,892,782	152,812,657
O&M Requested in Base Rates	$673,684,527	$692,348,863	$716,251,824
O&M in Colstrip Tracker	$27,794,431	$29,719,046	$34,976,134
Total O&M Requested	$701,478,958	$722,067,908	$751,227,957

This adjustment, which impacts the rate year periods, adjusts O&M to the level reflected in Table 10. This adjustment also sets the level of payroll taxes to match the wage expense that is included in the approved plan.

Additionally, page two of Exh. SEF-14, which has been referenced through this testimony, provides an overview of how the items within the approved plan were adjusted to be reflected on a Commission Basis.

23. Adjustment Nos. 6.23 and 11.23 – Advanced Meter Reading ("AMR") Regulatory Asset

Background and Requested Treatment

In 2016, PSE began replacing its Automatic Meter Reading meters and modules ("AMR" or "legacy assets") with Advanced Metering Infrastructure ("AMI") meters and modules. In PSE's 2019 general rate case, the AMI rollout was expected to be complete in 2022 or 2023. In Exh. CAK-1T, PSE witness Catherine A. Koch provides testimony on the prudency to convert PSE's metering system from AMR to AMI and the realized and expected benefits of the deployment. The revenue requirement adjustments associated with PSE's AMI investment is discussed in my next Adjustment. This Adjustment addresses the recovery of the remaining investment in PSE's AMR system.

PSE's 2019 general rate case contained discussion of the regulatory treatment for the legacy assets with the ultimate decision by the Commission being that the appropriate time to address the regulatory treatment of these legacy assets is when the AMI transition is complete.[80] As Ms. Koch testifies, PSE remains on track for the substantial completion of the rollout during PSE's first year of its multiyear rate plan in 2023. Accordingly, PSE is now requesting regulatory treatment for its AMR assets.

In 2000, PSE was an early adopter of AMR technology. The AMR system has been used and useful and providing benefits to customer for over twenty years. However, as Ms. Koch testifies, due to the development of next generation technology, the AMR system has become obsolete, and PSE is unable to obtain technical support or procure replacement parts going forward. The Commission also determined in the 2019 general rate case that "PSE provided ample testimony and evidence related to the obsolescence of its AMR system and the Company's inability to obtain technical support or procure replacement parts going forward."[81] This has resulted in only a portion of the AMR investment being recovered to date. Further, the replacement of an AMR system provides a unique challenge in that the system must continue to be maintained during the AMI roll out period. The above circumstances have resulted in the unrecovered investment for which PSE is seeking regulatory treatment.

PSE is requesting that it be allowed to establish a regulatory asset for the unrecovered AMR investment at the time the AMI rollout is complete, which is expected to be in December 2023, and that it be allowed recovery of, and a return

[80] *WUTC v. PSE*, Dockets UE-190529/ UG-190530, Order 08, ¶ 154 (July 8, 2020).
[81] *Id.* ¶ 153.

on, this regulatory asset beginning in 2023. Mr. Allis provides testimony in support of PSE's requested regulatory treatment and provides references to the regulatory treatment of unrecovered legacy meter costs in other jurisdictions. Furthermore, the Commission has historically provided a return on, and of, other prudently incurred unrecovered investment; for example, PSE's investments in the White River Hydroelectric Project[82] and the Electron Hydroelectric Project.[83] For its legacy assets, PSE is proposing an amortization period of twenty years, which is based on the original service lives of the legacy meters. Using an amortization period that is equivalent to the existing depreciation recovery pattern is similar to the treatment provided for the White River Hydroelectric Project and also results in a minimal impact to customers versus what is currently being recovered for AMR.

Based on the above, PSE requests that the Commission follow past practice and allow recovery of both the amortization over twenty years and the return on the regulatory asset balance. This treatment will prevent a disallowance on a prudently incurred investment.

Explanation of Adjustment

The net effect of retirements on mass plant assets such as the AMR system is that the unrecovered balance ends up in the accumulated depreciation (also known as

[82] Dockets UE-032043 and UE-090399.
[83] Docket UE-131099.

accumulated reserve) balance. A demonstration of the accounting is shown in Table 11 below.

Table 11. Accounting for Establishing the Regulatory Asset for AMR Retirements

Activity	Gross Plant		Accumulated Depreciation		Depreciation Expense	
	Debit	Credit	Debit	Credit	Debit	Credit
Beg Bal	$ 100			$ (55)		
Dep on Existing 7/21 - 11/23				$ (25)	$ 25	
Retirements Transfers		$ (100)	$ 100			
Ending Balances		$0	$ 20		$ 25	

In the above example, a group of assets starts with a beginning net book value ("NBV") of $45 ($100 of gross plant net of $55 of accumulated depreciation). The assets continue to depreciate—$25 dollars in this example—which results in a credit to the accumulated reserve that increases the balance. Concurrently, as assets are retired, a credit is made against gross plant for the book cost of the asset and an offsetting debit is made to the accumulated reserve.[84] Eventually, once all assets are retired, the ending gross plant balance is zero and the unrecovered investment (book cost minus accumulated reserve) is captured in the $20 debit balance in the accumulated reserve.

[84] Retirements also serve to lower depreciation expense. Also of note is that the retirement entry itself, the debit to the accumulated reserve and credit to gross plant, has no impact to rate base as both sides of the entry are included in rate base.

PSE followed the above accounting to calculate the regulatory asset balance for AMR. PSE started with the gross plant[85] that will eventually be retired and the accumulated depreciation balance as of the end of the test year. PSE then calculated a per-unit cost as of the end of the test year. The per unit cost was then applied to a unit retirement schedule supported by PSE witness Catherine A. Koch to determine the expected transfers from gross plant to accumulated depreciation as the assets are retired. These amounts established the transfer to the regulatory asset. In Adjustments 6.29 and 11.29, which I discuss below, an adjustment for the increase to depreciation expense that will occur on existing plant through the multiyear rate plan is made. Additionally, in adjustments 6.30 and 11.30, which are also discussed below, the adjustment to lower depreciation expense and the accumulated reserve for the retirement of test year plant is made. The amount of each of these adjustments associated with AMR retirements is based on the same unit retirement scheduled supported by Ms. Koch. PSE utilized the additional depreciation and offset it by the reduction to depreciation for retirements from these adjustments for AMR assets to increase the depreciation reserve in its calculation and thus decreased the balance of the regulatory asset to be recovered. On lines 21 and 24 of the adjustment, the final balance is then reclassified from the accumulated reserve (a rate base item) to the regulatory asset balance (another rate base item).

[85] AMR investment has historically been tracked in PSE's accounting system in a depreciation group that includes other investment that will not be retired with the AMR system. To determine the AMR gross plant balance as of the end of the test year, PSE utilized a ratio of the amount of the assets to be retired versus those that will not.

The regulatory asset balance is amortized over twenty years beginning December 2023. The related amortization expense is reflected on line 33. The corresponding reduction to depreciation expense for the utility plant that has been transferred to the regulatory asset is adjusted for in Adjustments 6.30 and 11.30 as noted above.

24. Adjustment Nos. 6.24 and 11.24 – Advanced Metering Infrastructure ("AMI") Plant and Deferral

Installation of PSE's advanced metering infrastructure began in 2016 under a strategy explained by PSE witness Catherine A. Koch. AMI provides communication network and metering equipment in PSE's electric and natural gas service territory that, as discussed above, will eventually replace its existing AMR system. This pro forma adjustment is comprised of the following components:

1. In paragraph 155 of Order 8 and paragraph 5 of Order 10 in PSE's 2019 general rate case, the Commission ordered that PSE should continue to defer the return on its AMI investment that was made through December 31, 2019. Accordingly, for purposes of conforming with WAC 480-07-510(3)(c)(i) only, the restating adjustment on line 35 removes AMI investment from rate base as the Commission has not yet allowed AMI investment to be included in rate base. The Commission allowed recovery of depreciation on PSE's AMI investment in the 2019 general rate case. Therefore, a corresponding restating adjustment to depreciation expense is not made. This adjustment is immediately reversed in the pro forma period as PSE is requesting all of its AMI investment be included in rate base in this proceeding. The justification for including AMI in rate base in this proceeding is supported by Ms. Koch.
2. An additional pro forma adjustment is made on line 39 which removes the entries to defer the return on AMI plant from the test year.
3. An adjustment in 2023 is made on line 40 to include the rate year amortization of the deferral of the return on AMI plant over three years. A three-year amortization period was chosen due to the relative size of the deferrals.
4. Although PSE believes that it has met all requirements to be allowed to include recovery on its existing and forecasted AMI investment, should the Commission not allow recovery of the return on AMI as requested, PSE

respectfully requests that it be allowed to continue to defer a return on the level of investment approved for AMI in this filing until a proceeding in which return on AMI is granted for recovery in rates.

25. Adjustment Nos. 6.25 and 11.25 – Get To Zero Deferral

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

A. As discussed in the Prefiled Direct Testimony of Suzanne Tamayo, Exh. SLT-1T, the GTZ projects comprise a customer-focused initiative to expand self-service options, remove obstacles for customers, provide proactive communication and quickly anticipate and solve problems for customers when they occur.

Q. Please explain the adjustment for GTZ.

A. This adjustment, which impacts all periods after the restating period, brings the amortization expense and rate base associated with the deferral of depreciation and carrying charges for GTZ program into rate base and net operating income. These deferrals have been maintained in two tranches.

Q. Please explain tranche one for GTZ.

A. Tranche one includes depreciation and carrying charges on GTZ assets with depreciable lives of ten years or less that were placed in service as of December 31, 2019. The ability to defer depreciation and carrying charges on tranche one was approved in PSE's 2019 general rate case.[86] The required ratemaking adjustments for tranche one are partially included in this adjustment with the

[86] *See* Order 10, ¶17.

remainder included in the Adjustments 6.49 and 11.49 “Regulatory Assets and Liabilities”. The portion included in Adjustments 6.49 and 11.49 is for deferred depreciation and carrying charges that occurred through April 2020 on GTZ investments as of December 31, 2019 as these amounts were incorporated in rates with the initial rate effective date from PSE’s 2019 general rate case. GTZ adjustments 6.25 and 11.25 include deferred depreciation and carrying charges that occurred between May 2020 and the initial rate effective date in PSE’s 2019 general rate case, on the same tranche, as these amounts have not yet been incorporated into rates.

The adjustments for tranche one are included on lines 25 through 27 and 40 and 41. The deferral balance is being amortized over three years which is the same time period utilized for the tranche one deferral that is currently included in rates.

Q. Please explain tranche two for GTZ.

A. Tranche two includes depreciation and carrying charges on GTZ assets with depreciable lives of ten years or less that have been placed in service after December 31, 2019. The ability to defer depreciation and carrying charges on tranche two was approved in paragraph 16 of Order 10 in PSE’s 2019 general rate case. This deferral balance consists of seven projects that were placed in service after December 31, 2019 as supported by Ms. Tamayo. The amortization period for the tranche two assets is also three years based on the relative size of the deferrals.

The adjustments for tranche two are included on lines 28 through 30 and 42 and 43. The deferral balance is also being amortized over three years which is the same time period utilized for the other GTZ deferrals.

Q. Are there other adjustments made related to the GTZ deferrals?

A. Yes. Line 39 provides an adjustment to remove the deferral entries for GTZ that were recorded in the test year. In previous rate cases, PSE has included adjustments of this nature to remove the originating deferral entries for deferrals being requested for recovery.[87]

Q. Would you please continue discussing the common adjustments?

A. Yes. The next common adjustment is:

26. Adjustment Nos. 6.26 and 11.26 - Environmental Remediation

The amortization of environmental remediation deferrals impacts multiple time periods. The restating adjustment is necessary to annualize the amortizations granted in Dockets UE-190529 and UG-190530 that are not fully reflected in the test year. The adjustment for the first rate year updates the amortization to include additional environmental remediation costs that have not been incorporated into rates as of the end of the test year. This adjustment also amortizes over five years a corresponding amount of the third party and insurance proceeds, either directly assigned or prorated, that are deferred as of June 30, 2021. This adjustment

[87] This need for such an adjustment was also recognized by the Commission in paragraph 16 of Order 10 in PSE's 2019 general rate case.

follows the allocation methodology that has been developed in collaboration with Commission Staff and that was utilized in Dockets UE-190529 and UG-190530.

The rate year three adjustment reduces the level of amortization to recognize that the layer of environmental remediation deferrals approved for recovery in the 2019 general rate case will be fully amortized by the third year of the multiyear rate plan.

27. Adjustment Nos. 6.27 and 11.27 – COVID Deferral

As discussed in Section III, PSE is requesting recovery of deferred direct costs net of cost savings as requested in Dockets UE-200780 and UG-200781. This adjustment estimates the deferral balance for the direct costs and savings as defined in PSE's petition. PSE's deferred direct costs including the deferral of foregone disconnect and reconnect fees totals $4.2 million. The type of costs deferred are outlined in PSE's petition. PSE did not defer any labor costs in this amount. Its deferral of cost savings is a payable of $2.2 million.

The deferred balances were determined by starting with their actual balances as of September 30, 2021 consistent with the quarterly reporting PSE has submitted to the Commission under Dockets UE-200780 and UG-200781. The deferrals were carried through March 31, 2022 at the same monthly level as was recognized in September 2021. The deferrals were stopped at March 31, 2022 as that is 180 days past the September 30, 2021 Resumption Date, as defined in Docket U-200281.[88] The amortization period for the deferrals is two years.

28. Adjustment Nos. 6.28 and 11.28 – Estimated Plant Retirements Rate Base

As discussed in Sections II.A and B, PSE is forecasting its entire utility plant balance in each of the rate years based on the roll-forward of its test year plant balances and its approved plant additions forecast as presented by Mr. Kensok. This adjustment recognizes the impact on gross plant and accumulated depreciation for the transfer that occurs when assets are retired as was demonstrated in Table 11 above. As shown in Table 11, the retirements transfer has no impact on overall rate base but is needed to present the appropriate amount of gross plant and accumulated depreciation when those categories are used independently.

This adjustment only includes the adjustment to rate base associated with retirements. Adjustment 6.30 adjusts for the impact of retirements on depreciation expense and accumulated depreciation. This adjustment and Adjustment 6.30 are companion adjustments to Adjustment 6.29 – Test Year Plant Roll Forward. Taken together, the three adjustments provide the benefit of the continued depreciation net of retirements that will occur on test year plant during the multiyear rate plan periods.

[88] Docket U-200281, Order 4, ¶ 9.

The estimated retirements are based on a historical three-year average of retirements. The method for estimating retirements is discussed in more detail in Adjustment 6.30. As discussed in Section II.B, retirements after 2021 included in this adjustment have been included in this filing subject to refund.

29. Adjustment Nos. 6.29 and 11.29 – Test Year Plant Roll Forward

As PSE is forecasting its full utility plant balance in each of the rate years, this adjustment provides the benefit of the additional depreciation that will occur on test year plant. Mr. Marcelia provides a detailed description of how this adjustment is calculated.[89] As discussed above, it does not include the impact of retirements, as those impacts are included in Adjustments 6.28 and 6.30.

This adjustment accommodates for three different impacts associated with rolling forward test year plant:

1. **Adjustments to Existing Test Year Depreciation** - Absent retirements, as test year depreciation expense is carried forward, the depreciation for depreciable assets will generally remain at the same level as these assets are depreciated on a straight line basis through the application of a depreciation rate. Changes to test year depreciation expense on existing plant that do occur with the passage of time are decreases to depreciation that are the result of a) asset classes that are accounted for using the end of life convention,[90] and b) intangible assets such as software that are on a set amortization schedule[91] so that depreciation expense on the asset ceases and overall depreciation expense is reduced once the intangible asset is fully amortized. This part of the adjustment accounts for the impact on depreciation expense and rate base for the benefit of the reduction to test year depreciation expense for end of life and intangible amortization. The impacts to rate base are the result of the additional accumulated depreciation that occurs as well as the corresponding

[89] *See* Exh. MRM-1T and Exh. MRM-3.
[90] As defined in Adjustment 6.20 and 11.20 above.
[91] As opposed to through the application of a depreciation rate.

impact to ADIT (not including EDIT). The adjustment to EDIT for both rate base and amortization are not included in this adjustment but are included in Adjustments 6.04 and 11.04 as discussed above.

2. **Incorporation of the Rates from the New Depreciation Study** – As discussed above, PSE is presenting a new depreciation study for approval in this filing. This adjustment reflects the use of PSE's existing depreciation rates through 2022 and the incorporating of new rates beginning in 2023, after the study is approved. Mr. Marcelia discusses how the existing and new depreciation rates were utilized in the calculation of this adjustment.

3. **Treatment of Colstrip Units 3 and 4 in the Net Salvage Component** – In paragraphs 424 through 426 of Order 8 in PSE's 2019 general rate case, the Commission allowed PSE to recover Colstrip D&R costs, which is a component of net salvage, in its existing depreciation rates, but required that PSE propose a tracking and true-up mechanism in this rate case to recover D&R costs in compliance with CETA. Adjustment 6.53 discusses PSE's proposed tracking and true-up mechanism. Because PSE is requesting to move the recovery of D&R costs for Colstrip Units 3 and 4 to a separate recovery mechanism, the new depreciation rates used in the calculation of this adjustment do not include D&R costs in the net salvage component for Colstrip Units 3 and 4. Mr. Allis discusses how these alternative rates are developed and presents them in his Exh. NWA-4. Accordingly, the natural gas and common depreciation rates used in this adjustment are supported in Exh. NWA-3, and the electric depreciation rates are supported in Exh. NWA-4. The electric depreciation rates provided by Mr. Allis in his Exh. NWA-3 include estimated D&R costs in the net salvage component for recovery through 2025. Should the Commission not accept PSE's proposal for including D&R in a tracking and true-up mechanism, the electric depreciation rates from Exh. NWA-3 that include the D&R component should be utilized in this adjustment, as well as adjustment 6.31 Programmatic Provisional Pro forma Additions. The difference that would result from moving the D&R recovery as proposed in the Colstrip tracker into the depreciation rates in this adjustment (so that D&R recovery would be included in base rates) is between $13 million to $16 million per year. The D&R costs in the tracker, net of PTCs, are recovered over the life of the remediation. The increase for moving recovery from PSE's proposed tracker into base rates is due to the costs being recovered over a much shorter time period as would traditionally occur in studied rates.

30. Adjustment Nos. 6.30 and 11.30 – Provisional Pro forma Retirements Depreciation

This adjustment is a companion adjustment to Adjustments 6.04, 11.04, 6.28, 11.28, 6.29 and 11.29 discussed above. This adjustment provides for the benefit of the decrease to depreciation expense and the corresponding impact on accumulated depreciation that will occur during the multiyear rate plan periods for the estimated retirements included in Adjustments 6.28 and 11.28. The impact on ADIT is included in Adjustments 6.29 and 11.29, and the impacts on EDIT rate base and amortization are included in Adjustment 6.04 and 11.04.

Mr. Marcelia discusses how this adjustment is calculated. PSE used a three-year historical average of retirements after adjustment for nonrecurring activity (e.g., the Colstrip Units 1 and 2 shut down, the sale of water heaters, etc.). A further refinement was made with respect to AMR retirements to replace the historical activity with PSE's projected replacement plan for those assets, which is the same underlying information used in calculating the regulatory asset for AMR discussed above for Adjustments 6.23 and 11.23.

This adjustment also takes into consideration the new depreciation rates discussed in Adjustments 6.29 and 11.29 above, in that retirements that occur after 2022 are valued at the proposed new depreciation rates.

31. Adjustment Nos. 6.31 and 11.31 – Programmatic Provisional Pro forma

This adjustment provides for the impact on depreciation expense and rate base for the pro forma and provisional pro forma adjustments related to PSE's forecasted program additions. I discuss how PSE has followed the guidance from the Used and Useful Policy Statement related to its provisional, pro forma adjustments in Section II.B. The method for calculating this adjustment is discussed by Mr. Marcelia. This adjustment also incorporates the depreciation rates from the new depreciation study effective January 1, 2023 as discussed in Adjustments 6.29 and 11.29.

A detail of the rate base by project or program has been provided in Exh. SEF-21. Exh. SEF-21 also provides the list of witnesses who discuss each of the specific and programmatic adjustments.

Q. Have you provided any additional information to assist in understanding the calculations that were performed to determine the rate base and depreciation impacts of the forecasted plant closings?

A. Yes. I have prepared Exh. SEF-15, which is a series of spreadsheets that re-calculate the results of the process utilized by Mr. Marcelia to determine the depreciation expense, accumulated depreciation, and FIT expense for both forecasted plant additions and retirements. Calculations for gross plant and ADIT are also provided for forecast plant additions. Exh. SEF-15 utilizes one project from Exh. JAK-5 as an example and steps through all of the complex calculations that are performed by the system utilized by Mr. Marcelia. This exhibit is provided in order to allow parties to conduct their own calculations if needed.

Q. Please continue explaining the revenue requirement adjustments.

A. The next adjustment is:

32. Adjustment Nos. 6.32 and 11.32 – Customer Driven Programmatic Provision Pro forma

This adjustment provides for the impact on depreciation expense and rate base for the pro forma and provisional pro forma adjustments related to PSE's forecasted program additions for customer driven programs such as programs for customer construction and public improvement. The additions in this adjustment are offset by the expected amounts to be received from customers in aid of construction that represent an offset to rate base. I discuss how PSE has followed the guidance from the Used and Useful Policy Statement related to its provisional pro forma adjustments in Section II.B. The method for calculating this adjustment is discussed by Mr. Marcelia. This adjustment also incorporates the depreciation rates from the new depreciation study effective January 1, 2023 as discussed in Adjustments 6.29 and 11.29.

A detail of the rate base by project or program has been provided in Exh. SEF-21 along with the sponsoring witness.

33. Adjustment Nos. 6.33 and 11.33 – Specific Provisional Pro forma Adjustments

This adjustment provides for the impact on depreciation expense and rate base for the pro forma and provisional pro forma adjustments related to PSE's forecasted additions for its specific projects. I discuss how PSE has followed the guidance from the Used and Useful Policy Statement related to its provisional pro forma adjustments in Section II.B. The method for calculating this adjustment is discussed by Mr. Marcelia. This adjustment also incorporates the depreciation rates from the new depreciation study effective January 1, 2023 as discussed in Adjustments 6.29 and 11.29.

A detail of the rate base by project or program has been provided in Exh. SEF-21 along with the sponsoring witness.

34. Adjustment Nos. 6.34 and 11.34 – Projected Provisional Pro forma

This adjustment provides for the impact on depreciation expense and rate base for the pro forma and provisional pro forma adjustments related to PSE's forecasted plant closings that have been assigned to the Projected category. I discuss how PSE has followed the guidance from the Used and Useful policy statement related to its provisional pro forma adjustments in Section II.B. The method for calculating this adjustment is discussed by Mr. Marcelia. This adjustment also incorporates the depreciation rates from the new depreciation study effective January 1, 2023 as discussed in Adjustments 6.29 and 11.29.

B. Electric Only Adjustments

Q. Please explain the electric only adjustments.

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

1. Adjustment No. 6.45 - Power Costs

This adjustment impacts multiple periods. The restating adjustment is applied in the same manner as in a Commission Basis Report and is intended to depict power costs under normal temperature and power supply conditions. Test year power costs are adjusted to recognize the changes in load and generation from test year levels summarized below. The following changes in load and generation are priced at the Mid-Columbia flat dollar per MWh embedded in rates that were in effect for the month being repriced.

1) the change in load used in the weather normalization adjustment (Adjustment No. 6.03), and
2) the adjustment to reflect hydro and wind volumes at normal levels based on levels assumed in the most recent rate case as they are also impacted by weather.

Additionally, an adjustment is required for the equity component of the TransAlta Centralia Coal Transition Power Purchase Agreement (“PPA”) approved by the Commission in Docket UE-121373. This adjustment is necessary to make actual booked expenses, which do not include regulatory adjustments, match the recovery built into rates. Further adjustments are required to this item in the rate years as the contracted volumes used to determine the equity adjustment decline.

The rate year adjustments represent the power costs that are projected to be incurred during the rate years. The calculation of the projected power costs for the rate years is explained by PSE witness Paul K. Wetherbee. The change in power costs between the 2020 PCORC, Docket UE-200980, and the current proceeding, are shown in Exh. PKW-4C. The change in power costs between rate years 1 and 2, and rate years 2 and 3 is included in Exh. PKW-5C.

Line 29 represents the production O&M that is forecasted for each of the rate years that is presented by Mr. Mark Carlson in Exh. MAC-1CT.

Line 30 presents the transmission expenses that are related to the Third AC, Northern Intertie and Colstrip transmission lines. This category of costs is left at its historical test year level and requires no adjustment.

Line 31 presents a forecast of revenues associated with variable transmission revenue earned under PSE's Open Access Transmission Tariff ("OATT") for retail wheeling, network and ancillary services.

The increase in Other Operating Revenue from the test year to the first rate year in 2023 stems primarily from BPA customer revenue forecasts and is due to a combination of both increased load forecasts between 2020 and 2022 and the increased formula rate in 2021. PSE uses load forecasts provided by BPA, and these reflect a cumulative increase between 2020 and 2022 of approximately 52 percent. The load forecast increase remains relatively flat between 2022 through 2025. The network and retail wheeling transmission formula rate increased by 33 percent in 2021. A three percent escalation to the rate was applied from 2022 through the end of the third rate year in 2025.

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

A. Yes. I have provided the corresponding fixed and variable power cost baseline rates in Exh. SEF-12. PSE will update these baseline rates at the very least at the compliance filing in this proceeding as these baseline rates will need to be approved for use in the accounting for PSE's PCA and electric fixed production decoupling mechanisms.

Q. Please continue with your discussion of the electric only adjustments.

A. The following are additional electric only adjustments.

2. Adjustment No. 6.46 - Montana Electric Tax

The restating adjustment adjusts the test year amount of Wholesale Energy Transaction Tax and Electricity and Electrical Energy License Tax to the amount that is related to the Colstrip generation included in the restating power cost adjustment.

The rate year adjustments modify the restated taxes to the amount that is projected to be incurred during the rate years based on the power generated at Colstrip that underlies the rate year power cost forecasts and is calculated at the current tax rates.

3. Adjustment No. 6.47 - Wild Horse Solar

This adjustment impacts multiple periods. The restating adjustment removes the effects of the solar project at PSE's Wild Horse wind facility. This solar power project is a demonstration project, and PSE is not requesting recovery of the costs associated with it at this time.

The adjustments beyond the restating period are made to counteract the results of moving test year rate base forward to the rate years in Adjustment 6.29. As discussed above, Adjustment 6.29 adds the additional depreciation expense and accumulated depreciation for test year utility plant that will occur through the rate years. Adjustment 6.29 starts with all test year plant and does not isolate projects such as Wild Horse Solar. Therefore, any inherent incremental changes to Wild Horse Solar that are occurring within Adjustment 6.29, such as the additional accumulated depreciation and the change to depreciation expense that occurs when the new depreciation rates begin being used in 2023, are removed through these adjustments.

4. Adjustment No. 6.48 - Storm Expense Normalization

This adjustment impacts the restating period and the first rate year. The restating adjustment adjusts the test year expense level of storm damage expense of $10.6 million to the normalized level of storm damage expense, based on the average of the most recent six years as has been done in prior general rate cases.

The adjustment for the first rate year (2023) adjusts the normalized storm expense in the restated results of operations to the current $10 million threshold level of storm expenses included in rates.

Because PSE uses a specific methodology for recovery of normalized storm expenses, PSE has replaced the specific amount of storm expense in the forecasted O&M with the $10 million threshold of normalized storm expense as indicated on page 2 of Exh. SEF-14.

5. Adjustment No. 6.49 - Regulatory Assets and Liabilities

This adjustment includes regulatory assets and liabilities that have been approved for recovery in a previous rate case and impacts all periods beyond the restating period to adjust certain regulatory assets and liabilities to the proper amounts in the rate years. The amortization of power costs-related regulatory assets and liabilities on lines 45 and 47 are considered variable costs in PSE's PCA mechanism and have been adjusted in the power cost adjustment, Adjustment 6.45. As a result, although the rate base section of this adjustment reflects the AMA of the rate year for both power cost and non-power cost regulatory assets and liabilities, only the non-power cost regulatory asset and liability amortizations for the rate years are reflected in this adjustment. The regulatory assets and liabilities for which amortization expires part way through the rate years only include amortization for the applicable months during the rate years.

Q. Are there any new items that have not been included in this adjustment in prior rate case filings?

A. Yes. The SPI Biomass PPA (line 32), Unprotected EDIT (lines 33 and 34), AMI (lines 35 and 36), and GTZ deferrals (lines 52 through 54) are new regulatory assets that were previously approved for recovery in PSE's 2019 general rate case and 2020 power cost only rate case. The GTZ deferrals on lines 36, 53, and 54 were discussed above in Adjustment 6.25. The AMI depreciation deferral was also approved for recovery in that case.[92]

Q. Please continue discussing the electric only adjustments.

A. The next adjustment is:

6. Adjustment No. 6.50 – Green Direct

This adjustment removes the rate base and operating expenses associated with PSE's Green Direct program as Washington law and prior Commission orders require that there be no cross-subsidization resulting from this voluntary program. The revenues for this program were removed in electric Adjustment 6.01. Additionally, the PPAs used to serve this program are not included in power costs as discussed by Mr. Wetherbee. Additional adjustments similar to those discussed for Wild Horse Solar in Adjustment 6.47 above are required beyond the restating

[92] *WUTC v. PSE*, Dockets UE-190529/UG-190530, Order 08 ¶ 155 (July 8, 2020).

period in order to neutralize the impacts of the adjustments to test year net utility plant from Adjustment 6.29.

7. Adjustment No. 6.51 – Storm Deferral Amortization

This adjustment relates to PSE's storm deferral mechanism.[93] PSE provides regular reporting on qualifying events in Docket UE-040641.

The restating adjustment is made to annualize the level of test year storm deferral amortizations to the level approved in PSE's 2019 general rate case.

The adjustment for the first rate year (2023) calculates the impact on amortization of new storm deferral balances that have not been previously approved. PSE's 2019 general rate case provided recovery of storm deferrals as of April 2019. This adjustment includes amortization for qualifying storms that have been deferred since that time for events that occurred in 2020 and 2021 through November 2021. There were seven qualifying events in 2020. There were nine qualifying events in 2021. This adjustment updates the amortization through the November 14, 2021 qualifying event which was the seventh event for 2021 and the most recent event for which deferred costs have been included in PSE's November close. PSE witness Catherine A. Koch discusses PSE's qualifying storm events.

[93] Paragraph 246 of Final Order No. 6, Dockets UE-040641 and UG 040640 et al; Paragraph No. 10 in Final Order No. 12 of Dockets UE-072300 and UG-072301 (consolidated), and paragraphs 206 and 299 of Order 08 in Dockets UE-111048 and UG-111049 (consolidated).

The adjustment for the third rate year (2025) is made to recognize that the storm amortization for the events that were approved for recovery in PSE's 2019 general rate case will finish amortizing in September 2025.

8. Adjustment No. 6.52 – Electric Vehicles Deferral

This adjustment has three main purposes, described as follows:

Recover the deferral authorized under Docket UE-190129

In Docket UE-190129, the Commission granted PSE's request to defer a return on its investment in its Electric Vehicle Supply Equipment ("EVSE") Portfolio[94] approved in Docket UE-180877 as well as to defer net costs for EVSE with carrying charges. Mr. Einstein provides testimony regarding program costs and investment that are included in this deferral. These deferred amounts relate to programs that PSE is operating to support transportation electrification consistent with Washington law and under the Commission's policy statement.[95] PSE has operated the programs prudently and as such, PSE now seeks recovery of the deferrals, including the deferred return.

This part of the adjustment includes the net cost deferral in rate base and the amortization of the deferred net costs, carrying charges, and return. The following provides a description of the method used for estimating the deferral balances as of December 31, 2022:

[94] PSE's program for electric vehicle offerings under its pilot program is titled: *Up & Go*.
[95] Laws of 2019, ch. 287, §1 and Laws of 2015, ch. 220, §1; Docket UE-160799.

Net Cost Deferral: There are four components to the net cost deferral. They are 1) direct program costs; 2) depreciation expense on EVSE investment; 3) power costs associated with public charging facilities; and 4) offsetting program revenues. For each component, the actual deferral balance as of September 30, 2021, plus forecasted amounts through December 2022, was used. The following describes the method for forecasting each component:

Direct Program Costs: The forecasted program costs for October through December 2021 were obtained from PSE's Outlook process. A description of PSE's Outlook process is provided by PSE witness, Joshua A. Kensok. The forecasted program costs for 2022 were obtained from the approved O&M forecast presented by Mr. Kensok.

Depreciation Expense: The forecasted depreciation expense for EVSE investment is included in Adjustments 6.29 based on existing test year investment. The board approved plan which is the basis for this adjustment assumes there is no additional investment expected before 2023. Because EVSE investment is not isolated within Adjustment 6.29, the forecasted depreciation expense was determined using a template similar to that provided in Exh. SEF-15.

Power Costs: The forecasted power costs were derived using forecasted consumption at PSE's public charging facilities under Schedules 551[96] priced at PSE's existing variable PCA baseline rate.

[96] Schedule 551 is PSE's Electric Vehicle Non-Residential Charging Products and Services.

Offsetting Program Revenues: The forecasted revenues that are applied to offset the deferred costs were determined using forecasted consumption under Schedules 551 and 552 priced at tariffed rates.[97]

Carrying Charges Deferral: The deferral for carrying charges was determined based on actuals as of September 30, 2021, that were recorded using the quarterly rate published by the Federal Energy Regulatory Commission[98] ("FERC"). The forecasted amount of carrying charges was calculated leaving the FERC rate the same as the third quarter in 2021 and applying it to the forecasted net cost deferral balance through 2022.

Return Deferral: The return deferral was calculated using actual deferred amounts as of September 30, 2021, which were recorded using actual plant balances and PSE's authorized rate of return from its expedited rate filing in Docket UE-180899 or its 2019 general rate case as appropriate. As in the depreciation deferral, no additional investment was expected before 2022. Therefore, the forecasted amounts of deferred return continue to be calculated using existing investment at PSE's authorized rate of return from its 2019 general rate case.

The amortization period selected for the net cost deferral is four years. These adjustments are made on lines 28, 38, 39 and 41.

[97] Schedule 552 is PSE's Electric Vehicle Residential Charging Products and Services.
[98] https://www.ferc.gov/interest-calculation-rates-and-methodology

Remove the deferral entries related to Docket UE-190129 from the test year

Lines 33 and 37 show the adjustment necessary to remove the deferral entries for the net cost deferral and the return deferral from the restated results. The deferral for carrying charges was booked below the line in interest income in the test year. Therefore, a similar adjustment is not necessary for the entries associated with the test year deferral of carrying charges.

Incentive return on investments made in PSE's Transportation Electrification Program

Mr. Einstein discusses PSE's request to recover an incentive return that is available on EVSE investments under RCW 80.28.360(2). Line 34 of this adjustment increases the revenue requirement in each rate year for the incentive return. The incentive return is calculated using a two percent return on eligible forecasted investment under PSE's Transportation Electrification Plan. The forecasted investment used for the calculation is from the approved forecast for plant closings as presented by Mr. Kensok, supported by Mr. Einstein, and included in Adjustment 6.33.

9. Adjustment No. 6.53 – Colstrip Decommissioning & Remediation Tracker

The purpose of this pro forma adjustment is to remove the amounts that PSE is proposing to be recovered through a separate tracking and true-up mechanism through electric tariff Schedule 141C. PSE is requesting approval of the proposed mechanism that is described in detail in Exh. SEF-18. Exh. SEF-18 also provides the detail of how this adjustment was developed.

10. Adjustment No. 6.55 – Monetize PTCs for Colstrip

In PSE's 2020 PCORC, PSE incorporated $150.7 million ($119.0 million net of tax) of monetized PTCs into rates. Because the 2020 PCORC rates went into effect on July 1, 2021 after the test year, monetized PTCs are not included in the test year rate base in Exh. SEF-5.

PSE recently monetized additional PTCs totaling $39.1 million ($30.9 million net of tax) on its 2020 tax return. Additionally, PSE anticipates it will monetize the remainder of its PTCs, or $45.3 million ($35.8 million net of tax), on its 2021 tax return that will be filed in 2022. This adjustment incorporates all the monetized PTCs into rates along with the corresponding interest at PSE's net of tax rate of return that has been accrued prior to their inclusion in rates.

Because monetized PTCs are earmarked to be used to offset unrecovered plant and decommissioning and remediation costs on all four units at Colstrip, the PTCs that are included in this adjustment are removed in Adjustment 6.53 above to be incorporated into PSE's proposed tracking mechanism for Colstrip.

11. Adjustment 6.56 – Acquisition Adjustments

PSE has a number of acquisition adjustments recognized in FERC account 114 related to past purchases of generating facilities, one of which will fully amortize during the multiyear rate plan. This adjustment adjusts rate base for the additional accumulated amortization that will occur through the multiyear rate plan periods and reduces amortization expense to recognize that the acquisition adjustment associated with the Encogen Generating Station will be fully amortized by 2023.

C. Natural Gas Only Adjustments

Q. Please explain the natural gas only adjustments.

A. Explanations of the natural gas only adjustments are as follows:

1. Adjustment No. 11.48 – Tacoma LNG Upgrades Plant and Deferral

The Tacoma Liquefied Natural Gas ("LNG") upgrades ("Upgrades") include the costs of a four mile section of new 16-inch pipeline and upgrades made to the Frederickson Gate Station that are necessary to support the Tacoma LNG Facility, but that were completed and placed in service prior to the LNG Facility's completion. In PSE's 2019 general rate case, the Commission authorized PSE to defer costs associated with these Tacoma LNG Upgrades.[99]

This adjustment serves three purposes. First, on lines 15, and 20 through 28, it provides for the recovery of the deferral. Second, similar to the AMI investment discussed in Adjustment 6.24, for purposes of conforming with WAC 480-07-510(3)(c)(i) only, the restating adjustment on line 6 removes the investment in the Tacoma LNG Upgrades from rate base as the Commission has not yet allowed these assets to be included in rate base. This adjustment is immediately reversed

[99] *WUTC v. PSE*, Dockets UE-190529/UG-190530 Order 8, ¶ 177 (July 8, 2020).

in the pro forma period as PSE is requesting that the Tacoma LNG Upgrades be included in rate base in this proceeding. Finally, the last reason for the adjustment is to remove from the test year the entries to record the depreciation deferrals. This part of the adjustment is shown on line 36. The deferral entries for the return were recognized below the line in FERC account 419 in the test year, so a corresponding adjustment for test year deferred return entries is not needed.

PSE witness Roque B. Bamba provides support for the Tacoma LNG Upgrades. Additionally, Mr. Roberts provides testimony describing how these Upgrades relate to the Tacoma LNG Project overall.

PSE is requesting recovery of both the depreciation and return on the Upgrades for the period after rates became effective in its 2019 general rate case through December 31, 2022. As Mr. Bamba testifies, the decision to invest in the Upgrades is a prudent decision and he also explains the difference in the in-service dates between the Upgrades and the Tacoma LNG Facility. I discuss below in Adjustment 11.49 the reasons that the Commission should allow PSE to recover the return on the Upgrades. As the decision to invest in the Upgrades is prudent, PSE would have had the rate base recovered in rates at its authorized rate of return commencing with the 2019 general rate case. Therefore, deferral and recovery of a return at PSE's authorized rate of return is appropriate.

To calculate the balance of the deferral as of December 31, 2022, PSE prepared a depreciation schedule for the Upgrades which have a total gross plant balance at the end of the test year of $32.3 million. As there are no plant additions for these Upgrades after that time, the rate base balances for these investments is known with certainty. The depreciation expense and calculated return at PSE's authorized net of tax rate of return on the declining rate base were then deferred through December 31, 2022, which resulted in a deferred balance of $4.7 million for return and $1.6 million for depreciation expense. These deferrals were then amortized over three years based on the magnitude of the deferred balances.

2. Adjustment No. 11.49 – Regulatory Assets and Liabilities

This adjustment is the gas equivalent to Adjustment 6.49 for electric. The AMI and GTZ deferrals are discussed in Adjustments 6.48 and 6.49. The rate base adjustment for unprotected EDIT was approved for recovery in PSE's 2019 general rate case.[100] PSE passes-back the unprotected EDIT in a separate tariff, Schedule 141Z, which is handled outside of a general rate case. The rate base for unprotected EDIT is included in base rates and not included in Schedule 141Z and is therefore adjusted here. This regulatory liability fully amortizes by 2024.

3. Adjustment No. 11.50 —Tacoma Liquefied Natural Gas

On November 24, 2021, PSE filed an accounting petition in Docket UG-210918 requesting deferral of the return, depreciation and operating expenses for the Tacoma LNG Facility ("the LNG Facility") as well as carrying charges on the depreciation and O&M deferral starting with its commercial operation date. Mr. Roberts provides testimony for the prudency and expected commercial operation

[100] *WUTC v. PSE*, Dockets UE-190529/UG-190530, Order 08 ¶ 325 (July 8, 2020).

date of the LNG Facility. In its accounting petition, PSE provided support for why the Commission should grant PSE's request for deferral, including deferral of return.[101] The reasons discussed in the petition are the same reasons the Commission should allow recovery of these costs. For these reasons PSE requests that the Commission allow recovery of PSE's deferral balances.

Mr. Roberts provides an overview of the expected costs of the LNG Facility. The deferral balances were determined using the expected capital and operating costs that are allocable to the regulated portion of the facility only. The capital additions utilized for this adjustment are included in the approved plant additions forecast presented by Mr. Kensok and the adjustment to include the rate base and depreciation for the LNG Facility in the revenue requirement is obtained from Adjustment 6.33. The forecasted operating costs utilized for this adjustment are included in the approved O&M forecast presented by Mr. Kensok, and the adjustment to include the operating costs of the LNG Facility in the revenue requirement is included in Adjustment 6.22. This adjustment includes the deferral balance for the corresponding costs prior to December 31, 2022 as requested in the petition. PSE did not include an adjustment for the amortization of carrying charges as it was de minimis when calculated (less than $7,000). The amortization period utilized for the deferrals is four years.

[101] Please see Docket UG-210918 for the detailed discussion.

Q. PSE is requesting recovery of various regulatory assets based on forecasted balances as of December 2022. Is it appropriate to allow these forecasted amounts in rates?

A. Yes. As has been done historically, the balance of regulatory assets are specifically tracked and any under or over amortization that occurs due to the difference in the forecasted and actual balances can be trued up in the next rate proceeding. During PSE's 2017 general rate case, the rate case following PSE's last multiyear rate plan, PSE had a number of storm deferral balances that had been over-amortized due to the five year stay out period. PSE maintained the balance of the over-amortized deferrals on its books and applied the balances against new storm deferrals in the 2017 general rate case after parties and the Commission had a chance to review the new storm deferrals.

VIII. POWER COST ADJUSTMENT MECHANISM

Q. Please summarize Exhibit A-1 in Exh. SEF-12 and explain its importance.

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

This variable baseline rate multiplied by the actual delivered load for a period is the amount of variable power costs that are included in customers' rates. The product of this calculation will be compared against only the actual allowable variable power costs during the reporting period plus any adjustments in Exhibit B,[102] such as the Centralia Equity Adder, to determine the imbalance for sharing against which the bands are applied to determine the deferral balance at the end of each PCA period. PSE has presented an Exhibit A-1 for each of the rate years in the multiyear rate plan. As discussed above in Section II.A, the variable power costs included in 2024 and 2025 represent a placeholder in that they only include known and signed contracts for those years. PSE witness Janet K. Phelps presents a proposal for updating the variable power costs during the multiyear rate plan in Exh. JKP-1T. PSE requests that the Commission provide approval of these schedules in this proceeding in order to provide certainty in its accounting for the PCA mechanism once new rates go into effect.

Q. Are there any new developments related to the PCA baseline rate?

A. Yes. In PSE's 2020 PCORC in Docket UE-200980, the treatment of load for PSE's Green Direct customers was established through settlement. Essentially, Green Direct customer load is not included when running Aurora for purposes of

[102] Exhibit B is the schedule that is used each year to calculate the overall imbalance in PSE's PCA mechanism.

determining power costs, and it is also not included in determining the baseline rate for calculating the PCA imbalance in Exhibit B. It is included in determining the variable unit cost for purposes of calculating the Energy Charge Credit under Schedule 139. Therefore, both the variable baseline rate used for Exhibit B and the variable baseline rate used for determining the Energy Charge Credit in Schedule 139 are presented on these exhibits. As part of the PCORC settlement, PSE engaged in a collaborative to reach agreement with parties on the appropriate way to determine the Energy Charge Credit. Mr. Einstein provides additional details regarding the collaborative process. If the results of the collaborative change the determination of the Energy Charge Credit to no longer utilize the PCA variable rate including Green Direct load, then this measure would no longer need to be calculated on these exhibits.

IX. COLSTRIP DECOMMISSIONING AND REMEDIATION TRACKER TRUE-UP MECHANISM

Q. Please explain the proposed Colstrip Decommissioning and Remediation Tracker Mechanism.

A. As noted above in the discussion of Adjustment 6.53, PSE's proposal for a Colstrip tracking and true-up mechanism is included in Exhs. SEF-18 and 19.

X. START UP COSTS FOR PSE'S VOLUNTARY RENEWABLE NATURAL GAS TARIFF SCHEDULE 138

Q. Please provide a brief history of the outstanding issue from PSE's Voluntary Renewable Natural Gas ("Voluntary RNG") program tariff filing under Docket UG-210194.

A. In Docket UG-190818, the Commission provided guidance in their policy statement on renewable natural gas programmatic design that all costs of Voluntary RNG programs should be borne by program participants. After due consideration of the policy statement, in Docket UG-210194, PSE stated its intention to request recovery of start-up costs associated with the development of software necessary to administer and bill for the voluntary program in general rates as opposed to recovering these costs in the program rate. PSE and other utilities provided arguments for allowing recovery of program start-up costs from all customers and these arguments are outlined in the Docket UG-210194. Ultimately, the Commission allowed PSE's program tariffs to go into effect by operation of law and did not opine on PSE's request to recover these costs in a future general rate case.

Q. Has PSE included the costs of the software upgrades for the Voluntary RNG program in this filing?

A. Yes. These costs were placed in service after the test year, in December 2021. They are included in PSE's forecasted capital additions in the traditional pro forma period in the projected category with an estimated plant closing amount of

$1.2 million. Mr. Einstein provides a discussion of the analysis performed in developing the functionality of the software and the ultimate actual costs.

Q. Why should the Commission allow recovery of these costs from all customers?

A. Mr. Einstein discusses why it is appropriate to allow recovery of these initial start-up costs from all gas customers in Exh. WTE-1CT.[103] Therefore, PSE respectfully requests that the Commission allow recovery of these costs in this proceeding.[104]

XI. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.

[103] The reasons for allowing recovery from all gas customers are further discussed in the filings in Docket UG-210194.

[104] As these costs were in service by December 31, 2021, which is within the traditional pro forma period, PSE is not requesting these costs subject to refund.