Exh. CRM-1T
Dockets UE-220066, UG-220067,
UG-210918
Witness: CHRIS R. MCGUIRE

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-220066, UG-220067, UG-210918 (consolidated)**
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility**	

TESTIMONY OF

Chris R. McGuire

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Electric and Natural Gas Revenue Requirements
Electric and Natural Gas Restating and Pro Forma Adjustments
Colstrip Tracker (Schedule 141C)

July 28, 2022

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Chris R. McGuire, and my business address is 621 Woodland Square Loop SE, Lacey, Washington, 98503. My business mailing address is P.O. Box 47250, Olympia, Washington, 98504-7250. My business email address is chris.mcguire@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I work in the Energy Regulation Section of the Regulatory Services Division of the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst. I have worked at the Commission since May 2012, and in my current position since February 2022.

Q. Would you please state your educational and professional background?

A. I graduated from the University of Washington in 2002 with a Bachelor of Science degree in Cell and Molecular Biology. I graduated from the University of Colorado in 2010 with a Master of Business Administration and a Master of Science in Environmental Studies. Prior to my employment with the Commission, I held research positions at various institutions, including the University of Washington, the University of Colorado, and the National Renewable Energy Laboratory. Since joining the Commission in 2012, I have held the positions of Regulatory Analyst (2012-2016, 2022-present), Energy Policy Strategist (2016-2018), Assistant Director of Energy Regulation (2018-2021), and Director of Legislation and Policy (2021-2022).

Q. Have you previously testified before the Commission?

A. Yes. With respect to Puget Sound Energy (PSE), I sponsored testimony on behalf of Commission Staff in the following adjudicated proceedings: PSE's 2017 general rate case (GRC), Dockets UE-170033 and UG-170034; PSE's 2018 expedited rate filing, Dockets UE-180899 and UG-180900; PSE's 2019 GRC, Dockets UE-190529 and UG-190530; and PSE's proposed sale of its ownership stake in Colstrip Unit 4, Docket UE-200115.

I also sponsored testimony on behalf of Commission Staff in Pacific Power's 2013 GRC, Docket UE-130043; Avista's 2014 GRC, Dockets UE-140188 and UG-140189; the initial and remand phases of Avista's 2015 GRC, Dockets UE-150204 and UG-150205; Avista's 2017 GRC, Dockets UE-170485 and UG-170486; Avista's 2019 GRC, Dockets UE-190334 and UG-190335; and Cascade's 2020 GRC, Docket UG-200568.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony is to present Staff's revenue requirement recommendations for PSE's electric and natural gas operations for each year the multiyear rate plan (MYRP). I sponsor exhibits for Staff's electric and natural gas revenue requirement models, including the restating and pro forma adjustments Staff contests. I provide testimony addressing pro forma operations and maintenance (O&M) expense (Adjustments 6.22 and 11.22) and adjustments pertaining to PSE's investments in the Tacoma LNG facility (Adjustments 11.33, 11.48, and 11.50).

I also address PSE's proposed Schedule 141C tracker for Colstrip-related costs, including the costs associated with PSE's investments made for the purpose of extending the life of Colstrip Units 3-4 beyond 2025.

Q. Please summarize Staff's recommendation on overall revenue requirement for each year of the MYRP.

A. For electric operations, Staff recommends the Commission authorize revenue requirements of $260.9 million in 2023, $302.1 million in 2024, and $296.3 million in 2025, corresponding to incremental electric revenue increases of $260.9 million in 2023 and $41.2 million in 2024, and an incremental reduction of $5.8 million in 2025.

Staff's recommendation on electric revenue requirement represents $859.3 million in additional revenues for PSE over the three-year rate plan, which is approximately $265.7 million less than PSE's as filed request for $1,125 million in additional revenue over the three years. Staff's recommendation on electric revenue requirements as compared to PSE's as-filed request is summarize in Table 1 of Section III, below.

For natural gas operations, Staff recommends the Commission authorize revenue requirements of $116.1 million in 2023, $138.5 million in 2024, and $160.5

million in 2025, corresponding to incremental electric revenue increases of $116.1 million in 2023, $22.4 million in 2024, and $22.0 million in 2025. Staff's recommendation on natural gas revenue requirements as compared to PSE's as-filed request is shown in Table 2 of Section III, below.

Staff's recommendation on natural gas revenue requirement represents $415 million in additional revenues for PSE over the three-year rate plan, which is approximately $165 million less than PSE's as filed request for $580 million in additional revenue.

Q. Do Staff's recommended revenue requirements include the impact of adjusting the Commission's regulatory fee from 0.2 percent to 0.4 percent of revenues, as will be required per the revisions to RCW 80.24.010?

A. No. Staff recommends that the Commission order PSE to incorporate the new regulatory fee of 0.4 percent into electric and natural gas revenue requirements on compliance.

Q. Please summarize Staff's recommendations regarding PSE's proposed Colstrip tracker (Schedule 141C).

A. Staff recommends the Commission approve the tracking mechanism but disallow recovery of the Dry Ash Waste Disposal System. Staff recommends the Commission set the Schedule 141C revenue requirement for 2023 at $50.5 million, which is $3.4 million less than PSE's as-filed request of $53.9 million.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. I prepared Exhibits CRM-2 through CRM-14.

Exh. CRM-2 Electric Net Revenue Change Recommendation
Exh. CRM-3 Electric Revenue Requirement Detailed Summary
Exh. CRM-4 Electric Restating and Pro Forma Adjustments
Exh. CRM-5 Natural Gas Net Revenue Change Recommendation
Exh. CRM-6 Natural Gas Revenue Requirement Detailed Summary
Exh. CRM-7 Natural Gas Restating and Pro Forma Adjustments
Exh. CRM-8 Rate Base, Net Operating Income and Revenue Requirement by Adjustment
Exh. CRM-9 PSE Response to UTC Staff Data Request No. 229
Exh. CRM-10 PSE Response to UTC Staff Data Request No. 230
Exh. CRM-11 Testimony of PSE Witness L. Anderson, Exh. LEA-1T, Docket UG-151663
Exh. CRM-12 PSE Response to UTC Staff Data Request No. 37
Exh. CRM -13 PSE Response to UTC Staff Data Request No. 182
Exh. CRM -14 Production O&M for Colstrip (Excerpt of PSE Workpapers for Colstrip Tracker)

- Exh. CRM-2 shows Staff's recommended net revenue change for PSE's electric operations for RY1 (2023), RY2 (2024), and RY3 (2025).
- Exh. CRM-3 provides a summary of Staff's revenue requirement calculations for PSE's electric operations.
- Exh. CRM-4 shows Staff's electric restating and pro forma adjustments.
- Exh. CRM-5 shows Staff's recommended net revenue change for PSE's natural gas operations for RY1 (2023), RY2 (2024), and RY3 (2025).
- Exh. CRM-6 provides a summary of Staff's revenue requirement calculations for PSE's electric operations.
- Exh. CRM-7 shows Staff's natural gas restating and pro forma adjustments.
- Exh. CRM-8 shows the net operating income (NOI) and revenue requirement impacts, by adjustment. Page 1 shows the NOI and rate base impacts, page 2 shows the revenue requirement impacts, pages 3 through 6

compare Staff's NOI and revenue requirements by adjustment to PSE's direct case, and pages 7 and 8 show NOI, rate base, and revenue requirements by contested issue for electric and gas operations, respectively.

- Exh. CRM-9 – PSE Response to UTC Staff Data Request No. 229 – shows the amount PSE included in pro forma O&M expense related to PSE's solar and storage DERs.
- Exh. CRM-10 – PSE Response to UTC Staff Data Request No. 230 – shows amounts PSE included in pro forma O&M expense for a management reserve.
- Exh. CRM -11 – Testimony of PSE Witness L. Anderson, Exh. LEA-1T, Docket UG-151663 – shows PSE's description of the purpose of the Bonney Lake upgrades for supporting peak capacity at the Tacoma LNG facility.
- Exh. CRM-12 – PSE Response to UTC Staff Data Request No. 37 – shows PSE's description of the Tacoma LNG capacity limitation resulting from the Bonney Lake upgrade not being completed.
- Exh. CRM-13 – PSE Response to UTC Staff Data Request No. 182 – shows gross plant in service by year for the Colstrip dry ash waste disposal system, from 2020 through 2025.
- Exh. CRM-14 shows the annual production O&M expense PSE projects for Colstrip for 2023-2025, with the major maintenance amortization expense for Colstrip 3-4 highlighted in yellow.

III. REVENUE REQUIREMENTS

A. Electric and Natural Gas Revenue Requirements

1. Summary of Staff's Revenue Requirement Recommendations

Q. Can you please provide a summary of Staff's overall revenue requirement recommendations for all three years of the multiyear rate plan?

A. Yes. Please refer to Table 1 and Table 2, below, which summarize Staff's revenue requirement recommendations for electric and gas operations, respectively, and provide a comparison of Staff's revenue requirement recommendations to PSE's requested revenue increases.

Table 1. Staff's recommended electric revenue increases as compared to PSE's as-filed request.

Electric	PSE Request		Staff Recommendation		Difference (Staff vs. PSE)	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
RY1 (2023)	330,013,401	330,013,401	260,906,947	260,906,947	(69,106,454)	(69,106,454)
RY2 (2024)	62,666,158	392,679,559	41,187,444	302,094,391	(21,478,714)	(90,585,168)
RY3 (2025)	10,185,740	402,865,299	(5,813,256)	296,281,135	(15,998,996)	(106,584,164)
3-yr Total		1,125,558,259		859,282,473		(266,275,786)

Table 2. Staff's recommended natural gas revenue increases as compared to PSE's as-filed request.

Natural Gas	PSE Request		Staff Recommendation		Difference (Staff vs. PSE)	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
RY 1 (2023)	165,483,178	165,483,178	116,109,065	116,109,065	(49,374,113)	(49,374,113)
RY 2 (2024)	29,889,927	195,373,105	22,403,996	138,513,061	(7,485,931)	(56,860,044)
RY 3 (2025)	23,327,182	218,700,287	21,956,726	160,469,787	(1,370,456)	(58,230,500)
3-year Total		579,556,570		410,338,784		(164,464,657)

Q. Do Staff's revenue requirement recommendations include the impact of the statutory change increasing the Commission's regulatory fee?

A. No. Although Staff understands that the amendment to RCW 80.24.010 increasing the Commission's regulatory fee from 0.2 percent of gross operating revenues to 0.4 percent[1] will increase PSE's revenue requirements, Staff does not expect the issue to be contentious or require litigation. As a result, Staff does not address the regulatory fee as a contested issue within this proceeding. Given the mechanical nature of incorporating the new regulatory fee into the Company's revenue requirement, Staff recommends that the Commission order PSE to incorporate the new regulatory fee into the revenue requirements on compliance.

2. Staff Response to PSE's Revenue Requirement Calculations

Q. How does PSE develop its electric and gas revenue requirements for each year of the MYRP?

A. PSE begins with its historical test year results of operations for the 12 months ended June 2021, and then makes four separate sets of adjustments to arrive at its projected revenue deficiency for RY1 (2023). The Company first makes restating adjustments (including restating the test year on an end-of-period basis), then a series of three pro forma adjustments: first through December 2021, then through December 2022, and then finally to arrive an average-of-monthly-averages presentation for RY1 (2023).

[1] LAWS OF 2022, ch. 159, § 1.

To arrive at its projected revenue deficiencies for RY2 and RY3, PSE adds to its AMA results of operations for 2023 a fifth set of pro forma adjustments to arrive at the Company's projected AMA results of operations for 2024, and a sixth set of pro forma adjustments to arrive at the Company's projected AMA results of operations for 2025.

Q. Does PSE use a modified historical test year approach for calculating its MYRP revenue requirements?

A. No, I do not believe it would be accurate to say PSE used a modified historical test year (MHTY) approach to develop the Company's projected revenue deficiency across the MYRP. While PSE began with a restated test year with traditional pro forma adjustments through December 2021, PSE's rate year revenue deficiency calculations are based largely on PSE's projected costs for each rate-effective period. The set of pro forma adjustments PSE makes to arrive at its RY1, RY2, and RY3 revenue requirements effectively replace PSE's historical costs and revenues with PSE's projected costs and revenues.

I believe it would be more accurate to characterize PSE's approach as a forecasted (or future) test year. While PSE's revenue requirement calculation begins with the Company's results of operations in the historical test year, it ends at the Company's forecast of its costs and revenues in future periods.

Q. Does Staff take issue with PSE's use of a forecasted test year for its revenue requirement calculations?

A. As a general matter, no. As I discuss in Section III.B, below, the recent statutory changes effected through SB 5295 essentially require rates to be based on forecasted costs and revenues.

However, I will note that PSE's RY1 revenue requirement includes projected plant-in-service at a date beyond what the law requires. While the law requires the Commission to value property used and useful "as of the rate effective date" for the initial rate year,[2] PSE's revenue requirement calculation values property across the full rate year (on an AMA basis). If the Commission were to value property used and useful "as of the rate effective date" it would use projected plant balances on an EOP 2022 basis.

Q. Is Staff contesting PSE's use of AMA 2023 (rather that EOP 2022) plant balances for its RY1 revenue requirement?

A. No.

Q. Why not?

A. The purpose of performing a revenue requirement calculation is to assess the level of revenues sufficient to cover the utility's cost of service *during the rate-effective period*. The plant-related costs that a utility incurs during a rate-effective period is most accurately captured using plant balances during that rate-effective period and

[2] RCW 80.28.425(3)(b) ("For 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.").

valued on an AMA basis, not using the EOP plant balances from the prior accounting period.

Having said that, the use of rate year AMA plant balances (rather that EOP plant balances from the prior period or, equivalently, plant balances as of the rate-effective date) eliminates regulatory lag. While utilities no doubt will cheer the elimination of regulatory lag, regulatory lag historically has provided utilities with an incentive to control costs. As I discuss in further detail in Section III.B, below, with the elimination of regulatory lag, the Commission will need to consider how it will incentivize utility cost control going forward.

Q. Which elements of PSE's revenue requirement calculations does Staff contest?

A. Staff's recommended reductions to PSE's as-filed revenue requirements are driven by the following:

a) A lower cost of capital relative to PSE's request (Parcell),
b) Adjustments to pro forma plant (Nightingale and McGuire),
c) Reductions to depreciation accrual rates (McCullar),
d) Removal of the return on AMI rate base (Snyder),
e) Removal of balances related to deferred return on rate base for AMI (Snyder) and Tacoma LNG (McGuire),
f) Removal of costs related to PSE's storage demonstration project and certain projected investments in distributed energy resources (Rector), and
g) Reductions to pro forma O&M expense (McGuire and Rector).

Q. Do you sponsor exhibits showing the calculation of Staff's recommended electric and natural gas revenue requirements for the multiyear rate plan (MYRP)?

A. Yes. For the electric revenue requirement calculations, I sponsor Exh. CRM-2 through Exh. CRM-4, and for the natural gas revenue requirement calculations I sponsor Exh. CRM-5 through Exh. CRM-7.

Q. What are Staff's recommended revenue requirements for PSE's electric and natural gas operations for each year of the MYRP?

A. Please see Table 1 and Table 2, above, which summarize the MYRP revenue requirements for PSE's electric and natural gas operations, respectively.

Q. Can you please summarize the impact of Staff's accounting adjustments?

A. Yes. Please see McGuire Exh. CRM-8 which summarizes the NOI, rate base, and revenue requirement impacts of Staff's electric Adjustments 6.01-6.56 and natural gas Adjustments 11.01-11.50.

I discuss the individual adjustments Staff contests in Section IV, below.

B. Noteworthy Implications of SB 5295

1. Implications of SB 5295 for Revenue Requirement Calculations

Q. Did SB 5295 – now codified as RCW 80.28.425 – impact how revenue requirements should be calculated in Washington State?

A. Yes. By requiring the Commission to ascertain rate base and operating costs during the rate-effective period, RCW 80.28.425 requires the Commission to set rates using forecasts of the utility's costs in a future period rather than actual costs from a completed (historical) period. Specifically, for ratemaking purposes the law requires the Commission to (a) value property that will be used and useful in each rate-effective period,[3] and (b) ascertain and determine revenues and operating expenses for each year of a MYRP.[4]

Q. What are the practical implications of moving from a historical cost basis to a forecasted cost basis.

A. In short, the first rate cases the Commission hears under the new, forward-looking ratemaking construct – where a utility's revenues are set for the first time using a forecasted cost basis – are likely to contain requests for revenue increases that are, relative to previous cases, quite large. The reason for this is that in addition to capturing increases to the utility's cost of service since its last GRC, the calculations capture the incremental effect using forecasted rather than historical costs when determining the utility's net cost of service for ratemaking purposes.

[3] RCW 80.28.425(3)(b) ("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.").
[4] RCW 80.28.425(3)(c) ("The commission shall ascertain and determine the revenues and operating expenses for rate-making purposes of any gas or electrical company for each rate year of the multiyear rate plan.").

Q. What do you mean by "the incremental effect using forecasted rather than historical costs?"

A. Under a traditional, historical test year approach, the Commission would have been attempting to ascertain PSE's cost of service over the period July 2020 through June 2021, with limited pro forma adjustments through June 2022 (roughly). Under the new, forecasted test year approach, the Commission is now attempting to ascertain PSE's cost of service using the Company's forecasts of its costs during the period January 2023 through December 2023, approximately 18 months later than under the historical approach.

Also, while the modified historical test year approach would have included pro forma adjustments intended to capture post-test year changes to the utility's costs, those pro forma adjustments would have been *limited*.[5] That is, not only would pro forma adjustments be temporally constrained, under the historical cost approach post-test year adjustments would have been limited to only those items the utility can demonstrate to cause a known, measurable, and material change to the utility's cost of service, not offset by other factors. The forecasted test year approach, on the other hand, while beginning at the same historical results of operations, includes pro forma adjustments intended to capture all (*i.e.*, unlimited) post-test year changes to costs and through a much later date.

In short, PSE's revenue request includes an additional 18 months of net cost growth unconstrained by traditional limitations on pro forma adjustments.

[5] The term "limited" in the context of pro forma adjustments refers to the traditional practice of limiting post-test year adjustments only to those items generating a known, measurable, and material change to the utility's cost of service, not offset by other factors. WAC 480-07-510(3)(c)(ii).

Accordingly, the increase in revenues PSE seeks – and the increase in revenues Staff recommends – is large indeed.

2. Implications of the Elimination of Regulatory Lag under SB 5295

Q. In addition to the impact on revenue requirement calculations you discuss above, are there any other implications of moving toward a forecasted test year approach to ratemaking?

A. Yes. The Commission should consider two primary implications of moving to a forecasted test year that effectively eliminates regulatory lag as it formulates its determinations in this case. The first relates to how the elimination of regulatory lag impacts the utility's incentive to control its costs, and the second relates to how the elimination of regulatory lag impacts the risk profile of the utility.

Q. How does the elimination of regulatory lag impact the utility's incentive to control its costs.

A. Under the traditional MHTY ratemaking paradigm, rates were calculated by measuring the utility's costs during an historical accounting period, and growth in the utility's net cost of service after that historical period (beyond that captured by limited pro forma adjustments) would not be captured in the Commission's rate-setting determinations. The fact that any further increases in the utility's cost of service would not be recovered in rates provided a strong incentive for the utility to control its costs; further increases in net cost of service would erode the utility's earnings. With the elimination of regulatory lag comes the elimination of the inherent cost-control incentives created by the presence of regulatory lag.

Without the utility cost-control incentive created by regulatory lag, it is critical that the Commission ensure that new cost control incentives are put into place and recognize when certain decisions or policies risk undermining the limited cost-control incentives the Commission has at its disposal or depriving the Commission of novel options for providing cost-control incentives in this new ratemaking paradigm.

Q. How does the elimination of regulatory lag impact the risk profile of the utility?

A. The elimination of regulatory lag is great for utilities not only because it moves revenue requirement calculations substantially in the utility's favor, but also because it reduces the utility's risk. With the elimination of regulatory lag, it is much, much more likely that the utility will earn at or above its authorized rate of return. And with a MYRP, the utility has predictable revenue over a multi-year time horizon, and is therefore better able to manage its costs according to those revenues. Given that the elimination of regulatory lag and the predictable revenues of a MYRP both reduce risk to the utility, it is important to consider whether that reduction in risk should be reflected in the utility's cost of capital, particularly its risk-adjusted return on equity. All else equal, businesses with less risk to investors should have a lower cost of equity.

As discussed in further detail by Staff Witness Parcell, the impact of SB 5295 on PSE's risk profile – specifically, that the legislation was substantially risk-reducing for PSE – argues strongly in favor of reducing PSE's authorized return on equity.[6]

IV. CONTESTED ADJUSTMENTS

Q. Which of PSE's accounting adjustments does Staff contest?

A. Staff contests the adjustments listed below. Please note that while the Staff witnesses identified in parenthesis sponsor testimony on issues impacting the identified adjustment, I sponsor the exhibits for the accounting adjustments themselves.

- Adjustments 6.22 and 11.22 – Pro Forma O&M (McGuire, Rector)
- Adjustments 6.24 and 11.24 – AMI Plant and Deferral (Snyder)
- Adjustments 6.29 and 11.29 – Test Year Plant Roll-Forward (McCullar)
- Adjustments 6.30 and 11.30 – Pro Forma Retirements (McCullar)
- Adjustments 6.31-6.34 and 11.31-11.34 – Pro Forma Plant (McCullar, McGuire, Nightingale, Rector)
- Adjustment 11.48 – Tacoma LNG upgrade plant and deferral (McGuire)
- Adjustment 11.50 – Tacoma LNG plant deferral (McGuire)

Q. Do you provide an exhibit that summarizes the impact of the accounting adjustments Staff contests?

[6] Parcell, Exh. DCP-1T at 18-22.

A. Yes. Exh. CRM-8 provides a comparison of the net revenue change by adjustment for the revenue requirement calculations performed by Staff and PSE.[7]

Please note that in Exh. CRM-8 there are adjustments beyond those identified in the bulleted list above that show revenue requirement differences (between Staff and PSE). The presence of revenue requirement differences for adjustments not identified in the bulleted list above (*i.e.*, for adjustments Staff does not contest) indicates adjustments with a rate base component where the calculation of the "revenue requirement impact" includes the effect of Staff's recommended rate of return.[8]

Q. Can you please provide additional detail on each contested adjustment and the reason Staff is contesting the adjustment?

A. Yes. I describe each of the contested adjustments in turn in the following subsections.

A. Pro Forma O&M – Adj. 6.22 (E) and Adj. 11.22 (G)

1. Summary of Staff Recommendation

[7] McGuire, Exh. CRM-8 at 4 (electric) and 6 (natural gas) provides comparisons of the net revenue change by adjustment for Staff's responsive case to that for PSE's direct case.

[8] Restating and pro forma adjustments themselves impact only net operating income (through adjustments to revenues and expenses) and rate base (through adjustments to rate base items, such as net plant and deferred taxes). In the overall revenue requirement calculation, the return on rate base is calculated at the aggregate level (rather than at the accounting adjustment level) by multiplying the rate of return by the utility's overall rate base. Therefore, only those adjustments where Staff's calculation of NOI or rate base differs from that of PSE should be considered contested adjustments.

Q. Can you please summarize Staff's recommendations regarding the level of pro forma O&M expense to include in Adjustments 6.22 (electric) and 11.22 (gas)?

A. Yes. Staff recommends the Commission remove from Adjustments 6.22 and 11.22 (1) forecasted O&M expense related to the "DER solar and storage" items identified in the Company's CEIP, and (2) amounts for a "management reserve."

Table 3 below shows the O&M expense increases Staff includes in pro forma O&M Adjustments 6.22 and 11.22, as compared to the amounts PSE included in its as-filed Adjustments 6.22 and 11.22.

Table 3. O&M expense increases included Adjustments 6.22 (electric) and 11.22 (gas) for each year of the MYRP (2023-2025)

Electric (Adj. 6.22)	**2023**	**2024**	**2025**
PSE O&M Increase[9]	78,032,532	12,752,102	14,243,120
Staff O&M Increase[10]	63,771,491	6,155,948	5,179,039
Reduction from PSE Request	(14,261,041)	(6,596,154)	(9,064,081)
Gas (Adj. 11.22)	**2023**	**2024**	**2025**
PSE O&M Increase[11]	36,182,215	5,561,668	4,894,968
Staff O&M Increase[12]	33,650,068	4,200,715	3,419,532
Reduction from PSE Request	(2,532,147)	(1,360,953)	(1,475,436)
Combined (E + G)	**2023**	**2024**	**2025**
PSE O&M Increase	114,214,747	18,313,770	19,138,088
Staff O&M Increase	97,421,559	10,356,663	8,598,571
Reduction from PSE Request	(16,793,188)	(7,957,107)	(10,539,517)

[9] Free, Exh. SEF-6 at 22, line 26
[10] McGuire, Exh. CRM-4 at 22, line 26
[11] Free, Exh. SEF-11 at 22, line 26
[12] McGuire, Exh. CRM-7 at 22, line 26

Q. What are the revenue requirement impacts of Staff's pro forma O&M Adjustments 6.22 (electric) and 11.22 (natural gas)?

A. Relative to PSE's as-filed Adjustment 6.22, Staff's Adjustment 6.22 reduces electric revenue requirement by approximately $15.0 million in 2023, $21.9 million in 2024, and $31.4 million in 2025.[13]

Relative to PSE's as-filed Adjustment 11.22, Staff's Adjustment 11.22 represents a reduction in natural gas revenue requirement of approximately $2.7 million in 2023, $4.1 million in 2024, and $5.6 million in 2025.[14]

2. Contested Components of PSE's O&M Expense Projections

Q. Which components of PSE's projected O&M increases does Staff contest?

A. Staff contests just two components of PSE's projected O&M expense increases: (1) amounts for a "management reserve," and (2) O&M expenses related the "DER solar and storage" activities identified in the Company's CEIP. Both items were included as "incremental," post-escalation components of PSE's projected O&M expense.

Q. What do you mean when you say "incremental," post-escalation components of PSE's projected O&M?

[13] McGuire, Exh. CRM-8 at page 7:16-17.
[14] McGuire, Exh. CRM-8 at page 8:16-17.

A. PSE's process for developing an O&M forecast involves first applying escalation factors to two categories of historical O&M expense (labor and outside services),[15] and then adding onto the escalated O&M expense additional costs PSE believes are not already captured in the escalated O&M expense.[16] In its workpapers PSE refers to the post-escalation add-ons as "incremental" O&M.

Q. Can you please describe Staff's concerns with the "DER solar and storage" O&M and the "management reserve?"

A. Yes. I discuss each, in turn, in the subsections that follow.

a. "DER Solar and Storage" O&M

Q. Which Staff witness addresses the contested O&M expense related to "DER solar and storage" activities?

A. Staff witness Rector addresses this issue in Exh. ASR-1T.

Q. What activities do the "DER solar and storage" O&M expenses pertain to?

A. The "DER solar and storage" O&M pertains to various distributed solar and storage resources and programs PSE included in its CEIP.[17] PSE Witness Jacobs provides a

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[15] PSE escalates labor by 3.5 percent per year and outside services by 2 percent per year. Together, labor and outside services make up approximately 80 percent of PSE's O&M expense. *See* Kensok Exh. JAK-1T at 16:10-13.

[16] Kensok, Exh. JAK-1T at 15:9-10.

[17] *See* Jacobs, Exh. JJJ-3, Appendix A-2 and Appendix A-3.

summary of the projected O&M expenses related to items identified in the Company's CEIP, including for "DER resources." [18]

Q. What incremental O&M does PSE include in its electric Adjustment 6.22 related to "DER solar and storage" O&M?

A. In its direct case, PSE identifies projected increases in O&M expense related to "DER solar and storage" of $9.2 million in 2023, $13.3 million in 2024, and $19.5 million in 2025,[19] although in response to discovery PSE indicated that the actual amount the Company included in revenue requirement for 2023 was $9.35 million.[20]

Q. What are Staff's concerns with the costs PSE included in revenue requirement related to "DER solar and storage" O&M?

A. As explained in further detail by Staff witness Rector,[21] PSE is not likely to undertake the "DER solar and storage" activities identified in the CEIP and, accordingly, the O&M expenses PSE projected for those activities represent costs the Company is not likely to incur during the MYRP. Therefore, the O&M expense associated with the "DER solar and storage" activities identified in PSE's CEIP do not meet the Commission's known and measurable ratemaking standard.

Q. What is Staff's recommendation on the incremental O&M increases related to "DER solar and storage resources?"

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[18] Jacobs, Exh. JJJ-1T, Table 2 at 29:1.
[19] Jacobs, Exh. JJJ-1T, Table 2 at 29:1.
[20] McGuire, Exh. CRM-9, at 2.
[21] Rector, Exh. ASR-1T at 38:16-22.

A. Staff recommends the Commission remove from PSE's Adjustment 6.22 the full amount of projected O&M expenses related to "DER solar and storage" activities for each year of the MYRP: $9.35 million in 2023, $13.3 million in 2024, and $19.5 million in 2025.

b. "Management Reserve"

Q. Which Staff witness addresses the contested "management reserve" PSE included in its pro forma O&M Adjustments 6.22 and 11.22?

A. I am the witness of record for Staff on the issue of PSE's management reserve.

Q. What amount of incremental "Management Reserve" does PSE include in its revenue requirement calculation for each year of the MYRP?

A. While a "management reserve" is not identified in any of PSE's exhibits, in response to discovery PSE identified annual amounts for a management reserve on a total-Company basis $7.4 million in 2023, $11.5 million in 2024, and $15.8 million in 2025.[22] Allocated to electric operations, these amounts correspond to management reserves of $4.9 million in 2023, $7.6 million in 2024, and $10.4 million in 2025, which PSE included in its electric Adjustment 6.22. Allocated to natural gas operations, these amounts correspond to management reserves of $2.5 million in 2023, $3.9 million in 2024, and $5.4 million in 2025, which PSE included in its natural gas Adjustment 11.22.

[22] McGuire, Exh. CRM-10 at 5.

Q. Did PSE provide a description and justification for the increase in revenues it requests associated with the management reserve?

A. No. PSE's testimony does not address the increase in revenue the Company seeks for a management reserve.

Q. Did Staff seek additional information on the "Management Reserve" through discovery?

A. Yes. In response to discovery, PSE provided an explanation of the management reserve which the Company described as a "risk management planning tool" and identifies that its purpose is "to fund unforeseen major events."[23]

Q. Is it appropriate to include a management reserve in PSE's revenue requirement calculations?

A. No.

Q. Why is it not appropriate to include the management reserve in PSE's revenue requirement calculations?

A. The amount PSE included in its revenue request for a management reserve - $34.7 million over the MYRP – is to fund "unforeseen events" that the Company itself acknowledges might not occur.[24] Amounts for such unforeseen events fall substantially short of the Commission's "known and measurable" ratemaking standard. As the Commission reaffirmed in its Used & Useful Policy Statement,

[23] McGuire Exh. CRM-10, at 2.
[24] *Id.*

"The known and measurable standard continues to require that an event that causes a change to revenue, expenses, or rate base must be "known" to have occurred during or after the historical 12-months of actual results of operations. It must also be demonstrated (i.e., known) that the effect of the event will be in place during the rate year."[25]

The unforeseen events PSE seeks to fund by including a management reserve in revenue requirement are, by definition, unknown and, thus, the effects of said unforeseen events on the Company's overall cost of service cannot be measured.

In addition to failing the Commission's known and measurable standard, amounts in revenue requirement for "unforeseen events" cannot meet the Commission's prudency standard. Without an identified expenditure, there is nothing for the Commission to examine to determine whether that expense was (or likely will be) prudently incurred or whether it is appropriate to recover from ratepayers.

Q. What do you recommend regarding the amounts PSE included in its revenue requirement calculations for a management reserve?

A. I recommend that the Commission remove the management reserve in full from revenue requirement. For electric operations, Staff recommends that the Commission remove from PSE's Adjustment 6.22 the management reserves of $4.9 million in 2023, $7.6 million in 2024, and $10.4 million in 2025. For natural gas operations, Staff recommends that the Commission remove from PSE's Adjustment 11.22 the

[25] *In re the Comm'n's Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Serv. Ratemaking*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date, 8 ¶ 22 (January 31, 2020) (citing *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Docket Nos. UE-090134 & UG-090135, Order 10, 21 ¶ 45 (Dec. 22, 2009)).

management reserves of $2.5 million in 2023, $3.9 million in 2024, and $5.4 million in 2025.

Q. Do you have an alternative recommendation for the Commission to consider for the management reserve PSE includes in its revenue requirement calculations?

A. Yes. Given the high volume of petitions for deferred accounting filed with the Commission in recent years, the Commission is well aware that a regulatory tool already exists for the purpose of enabling utilities the opportunity to recover the costs of "unforeseen major events." If the Commission allows into rates a management reserve that the Company has explicitly stated is for the purpose of "fund[ing] unforeseen major events," the Commission should deny all petitions for deferred accounting that would otherwise serve that same purpose. Indeed, if the Commission is exploring opportunities to relieve regulatory burden, including a management reserve in rates with the stated purpose of eliminating the need for petitions for deferred accounting may be one such opportunity.

B. AMI Deferral and Return on Rate Base – Adj. 6.24 (E) and Adj. 11.24 (G)

Q. What specifically does Staff contest with respect to AMI rate base?

A. Staff contests (1) PSE's requested recovery of the cumulative deferral balance as of December 31, 2022, associated with a deferred return on AMI investments, and (2) PSE's inclusion of AMI in rate base going forward.

Q. What does Staff recommend regarding a return on AMI rate base?

A. Witness Snyder recommends the Commission remove the return on AMI rate base from electric and gas revenue requirements but allow PSE to continue deferring a return on AMI investment until such time as the Company files an updated AMI implementation plan that maximizes benefits to the Company and customers.[26]

Q. What does PSE include in its revenue requirement related to the recovery of the AMI return deferral?

A. With respect to the AMI return deferral, for the deferred return on electric AMI PSE includes in its Adjustment 6.24 an annual amortization expense of $8.3 million reflecting a three-year amortization of the cumulative deferral balance of $25.0 million.[27] For the deferred return on natural gas AMI, PSE includes in its Adjustment 11.24 an annual amortization expense of $3.5 million, reflecting a three-year amortization of the cumulative deferral balance of $10.5 million.[28]

Q. What does PSE include in its revenue requirement related to going-forward return on AMI rate base?

A. With respect to going-forward AMI rate base, for electric operations PSE included in its Adjustment 6.24 an AMI net rate base of $143.0 million for all three rate years,[29] and included in its Adjustment 6.31 an additional $27.7 million in 2023, $118.7

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[26] Snyder Exh. JES 1-T, at 3:11-14.
[27] Free Exh. SEF-6, at 24:40.
[28] Free Exh. SEF-11, at 24:40.
[29] Free Exh. SEF-6, at 24:20.

million in 2024, and $108.2 million in 2025.[30] For natural gas operations PSE included in its Adjustment 11.24 an AMI net rate base of $65.6 million for all three rate years,[31] and included in its Adjustment 11.31 an additional $13.9 million in 2023, $67.7 million in 2024, and $60.3 million in 2025.[32]

Q. How does Staff incorporate the recommendation to remove the return on rate base into its revenue requirement calculations?

A. Staff takes three steps to remove the return on AMI rate base from its revenue requirement calculations. First, Staff removes amortization of the AMI return deferral from Adjustments 6.24 and 11.24. Second, Staff removes the test year AMI rate base PSE had included in its Adjustments 6.24 and 11.24. And third, Staff removes the AMI rate base PSE had included in its pro forma plant Adjustments 6.31 and 11.31

Q. What is the impact Staff's removal of the AMI return deferral PSE from Adjustments 6.24 and 11.24?

For electric operations, Staff removes an annual amortization expense of $6.5 million for electric operations[33] and $2.8 million for natural gas operations,[34] which are the amounts specifically associated with deferred return on AMI rate base. The amortization expense Staff retains in its Adjustments 6.24 and 11.24 – $1.8 million

[30] Free Exh. SEF-21, at 1:8.
[31] Free Exh. SEF-11, at 24:20.
[32] Free Exh. SEF-21, at 2:8.
[33] From $8,344,284, as shown in Free Exh. SEF-6, at 24:25, to $1,830,247, as shown in McGuire Exh. CRM-4, at 24:25.
[34] From $3,499,802, as shown in Free Exh. SEF-11, at 24:25, to $741,782, as shown in McGuire Exh. CRM-7, at 24:25.

for electric[35] and $0.7 million for natural gas[36] – relate to a depreciation deferral and not the return deferral.

Staff's recommendation to remove amortization of the return deferral from Adjustments 6.24 and 11.24 reduces revenue requirement for each year of the MYRP by $6.8 million for electric operations[37] and $2.9 million for natural gas operations.[38]

Q. Through which adjustments does Staff remove rate base associated with pro forma AMI plant additions?

A. To keep the AMI rate base adjustments in one place, Staff removed AMI rate base related to pro forma plant from electric revenue requirement through Adjustment 6.24 and from its natural gas revenue requirement through Adjustment 11.24.[39]

Q. What is the impact of removing the going-forward return on AMI rate base??

A. For electric operations, Staff removed from rate base approximately $170.7 million in 2023, $261.7 million in 2024, and $251.2 in 2025 which reduced revenue requirement by $14.8 million in 2023, $22.7 million in 2024, and $21.9 million in 2025.[40]

For natural gas operations, Staff removed from rate base approximately $79.5 million in 2023, $133.3 million in 2024, and $125.9 million in 2025 which reduced

[35] McGuire Exh. CRM-4, at 24:40.
[36] McGuire Exh. CRM-7, at 24:40.
[37] McGuire Exh. CRM-8, at 7:7.
[38] McGuire Exh. CRM-8, at 8:7.
[39] McGuire Exh. CRM-4, at 24:20, 26, 32; McGuire Exh. CRM-7, at 24:20, 26, 32.
[40] McGuire Exh. CRM-8, at 7:13.

revenue requirement by $6.9 million in 2023, $11.6 million in 2024, and $11.0 million in 2025.[41]

Q. What is the overall revenue requirement impact associated with Staff's Adjustments 6.24 and 11.24?

Relative to PSE's as-filed electric Adjustment 6.24, Staff's Adjustment 6.24 – which includes the impact of removing the electric return deferral as well as the return on electric AMI rate base going forward – reduces electric revenue requirement by $22.8 million in 2023, $31.4 million in 2024, and 30.4 million in 2025. [42]

Relative to PSE's as-filed Adjustment 11.24, Staff's Adjustment 11.24 reduces natural gas revenue requirement by $10.3 million in 2023, $15.5 million in 2024, and $14.7 million in 2025. [43]

C. Test Year Plant Roll-Forward – Adj. 6.29 (E) and Adj. 11.29 (G)

Q. Which elements of PSE Adjustments 6.29 and 11.29 is Staff contesting?

A. Staff is contesting the elements of Adjustments 6.29 and 11.29 impacted by Staff witness McCullar's recommendations on depreciation accrual rates.

Q. How do witness McCullar's recommendations on depreciation accrual rates impact Adjustments 6.29 and 11.29?

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[41] McGuire Exh. CRM-8, at 8:13.
[42] McGuire Exh. CRM-8 at 4:24.
[43] McGuire Exh. CRM-8 at 6:24.

A. Adjustments 6.29 and 11.29 roll test year plant balances forward to each rate year, capturing the effect of accumulated depreciation between the test year and RY1, and between each successive rate year. Staff witness McCullar's recommended depreciation rates impact Adjustments 6.29 and 11.29 in two ways: first through the calculation of depreciation expense in the rate years associated with test year plant, and second through the calculation of accumulated depreciation and deferred taxes which impact revenue requirement through rate base.

Q. What is the revenue requirement impact of reflecting Staff's recommended depreciation accrual rates in Adjustments 6.29 and 11.29?

A. Relative to PSE's as-filed case, reflecting Staff's recommended depreciation accrual rates in Adjustment 6.29 decreases electric revenue requirement by approximately $1.9 million in 2023, $1.7 million in 2024, and $1.5 million in 2025.[44]

Relative to PSE's as-filed case, reflecting Staff's recommended depreciation accrual rates in Adjustment 11.29 decreases natural gas revenue requirement by approximately $9.2 million in 2023, $8.3 million in 2024, and $7.2 million in 2025.[45]

D. Pro Forma Retirements – Adj. 6.30 (E) and Adj. 11.30 (G)

Q. Which elements of PSE Adjustments 6.30 and 11.30 is Staff contesting?

A. Staff is contesting the elements of Adjustments 6.30 and 11.30 impacted by Staff witness McCullar's recommendations on depreciation accrual rates.

[44] McGuire Exh. CRM-8 at 7:20.
[45] McGuire Exh. CRM-8 at 8:20.

Q. How do witness McCullar's recommendations on depreciation accrual rates impact Adjustments 6.30 and 11.30?

A. Adjustments 6.30 and 11.30 remove from revenue requirement the costs associated with test year plant that since has been (or will be) retired by each rate-effective period. While PSE's Adjustments 6.30 and 11.30 remove depreciation expense calculated at PSE's proposed depreciation accrual rates, Staff's Adjustments 6.30 and 11.30 remove depreciation expense calculated at witness McCullar's proposed depreciation accrual rates; effectively, Staff's adjustment removes less depreciation expense.

Q. What is the revenue requirement impact of reflecting Staff's recommended depreciation accrual rates in Adjustments 6.30 and 11.30?

A. Relative to PSE's as-filed case, reflecting Staff's recommended depreciation accrual rates in Adjustment 6.30/11.30 has an immaterial impact on electric revenue requirements,[46] and a marginally immaterial impact on natural gas revenue requirement (at between $0.06 million in 2023 and $0.1 million in 2025). [47]

E. Pro Forma Plant – Adjs. 6.31-6.34 (E) and Adjs. 11.31-11.34 (G)

Q. Can you please identify the Staff witnesses contesting issues that impact pro forma plant Adjustments 6.31-6.34 (electric) and 11.31-11.34 (gas)?

[46] *See* Exh. CRM-8 at 7:21.
[47] *See* Exh. CRM-8 at 8:21.

A. Yes. The Staff following witnesses contest issues impacting the pro forma plant adjustments:

- Staff witness McCullar addresses PSE's depreciation study and the associated depreciation accrual rates PSE uses for its depreciation expense calculations in Adjustments 6.31-6.34 and 11.31-11.34.
- I address the Tacoma LNG plant-related costs PSE included in its natural gas Adjustment 11.33.
- Staff witness Nightingale addresses the Energize Eastside plant-related costs PSE included in its electric Adjustment 6.33.
- Staff witness Rector addresses DER plant-related costs PSE included in its electric Adjustment 6.31.

Q. Can you please explain how Staff's recommendations on each of the items in the bulleted list above impact revenue requirements through Adjustments 6.31-6.34 and 11.31-11.34?

A. Yes. I will address how Staff's recommendations on each of the list items impact Adjustments 6.31-6.34 and 11.31-11.34 in the following subsections.

1. Depreciation Accrual Rates (Adjs. 6.31-6.34 and 11.31-11.34)

Q. What does Staff Witness McCullar recommend with respect to depreciation accrual rates that impacts pro forma plant?

A. Staff Witness McCullar recommends rejecting PSE's proposed modifications to the salvage value assumptions for electric depreciation group E3660 (U/G conduit), and gas depreciation groups G3802 (DST Services, Plastic) and G3803 (DST Services, Steel-wrapped). Accordingly, Witness McCullar's recommended depreciation accrual rates affect the going-forward depreciation expense for plant recorded to those accounts which, in turn, affects accumulated depreciation and deferred income taxes in each year of the MYRP.

Most of the pro forma plant additions to depreciation groups E3660, G3802, and G3803 are included in PSE's revenue requirement calculations via Adjustment 6.31/11.31 ("programmatic"), though additional amounts for all three accounts are included in Adjustments 6.32/11.32 ("customer-driven") and 6.34/11.34 ("projected").

Q. What are the revenue requirement impacts associated with Witness McCullar's recommendations on depreciation accrual rates?

A. Specifically with respect to the impact via the electric pro forma plant Adjustments 6.31-6.34,[48] relative to PSE's as-filed request witness McCullar's recommended depreciation accrual rate for E3660 (U/G conduit) reduces electric revenue requirement by approximately $0.2 million in 2023, $0.3 million in 2024, and $0.4 million in 2025.[49]

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[48] Witness McCullar's recommended depreciation accrual rates also affect Adjustment 6.29/11.29 (test year plant roll-forward) and Adjustment 6.30/11.30 (pro forma retirements), the impacts of which are identified separately above.

[49] McGuire Exh. CRM-8 at 7:22.

With respect to the impact via natural gas pro forma plant Adjustments 11.31-11.34, relative to PSE's as-filed request witness McCullar's recommended depreciation accrual rates for G3802 and G3803 reduce natural gas revenue requirement by approximately $0.8 million in 2023, $1.1 million in 2024, and $1.4 million in 2025.[50]

2. Tacoma LNG (Adjustment 11.33)

Q. Which Staff witness sponsors testimony on the Tacoma LNG plant balances PSE includes in its natural gas revenue requirement calculation?

A. I address plant balances associated with PSE's investment in the Tacoma LNG facility.

Q. What does Staff contest with respect to the Tacoma LNG facility?

A. Staff contests the level of plant in Adjustment 11.33 that PSE considers used and useful.

Q. What is the issue with the level of Tacoma LNG plant PSE included in revenue requirement via Adjustment 11.33?

A. A significant portion of the facility is not used and useful to ratepayers, yet PSE includes 100 percent of the facility in revenue requirement.

[50] McGuire Exh. CRM-8 at 8:22.

Q. Why is a significant portion of the facility not used and useful?

The purpose of Tacoma LNG Facility is to serve the peak day requirements for PSE's regulated gas customers. Due to the Company's failure to complete planned upgrades to the Bonney Lake lateral, the facility is limited to approximately 76 percent of its maximum capacity as a peaking facility.

Q. What was the purpose of the upgrades to the Bonney Lake lateral?

A. The upgrades to the Bonney Lake lateral were needed to facilitate injection of vaporized gas for peaking service. More specifically, the upgrades to the Bonney Lake lateral were necessary to allow the outlet pressure at the North Tacoma Gate Station to be lowered which is a requirement for injection volumes above 50 million cubic feet per day (MMCFD). [51]

Q. Did PSE and Puget LNG complete the work necessary to the Bonney Lake lateral to reduce the North Tacoma Gate Station outlet pressure?

A. No.[52]

Q. What impact does not completing the upgrades to the Bonney Lake lateral have on the Tacoma LNG facility's peak day injection capacity?

A. As a peak day resource for regulated customers, the Tacoma LNG Project was originally designed to be capable of injecting 66,000 MMCFD of vaporized gas

[51] McGuire, Exh. CRM-11 at 6:3 to 15.
[52] McGuire, Exh. CRM-12.

directly onto PSE's gas distribution system. However, with the Bonney Lake lateral incomplete, injection capacity is limited to 50,000 MMCFD.[53]

Q. When does PSE expect Tacoma LNG to be available at full capacity?

A. It appears that PSE does not expect the full capacity to be available until at least late 2024. In PSE's 2021 IRP, the Company states that the full capacity "will become available when additional upgrades to the natural gas distribution system allow vaporization of an additional 16 MDth per day; this additional capacity is assumed to be available as a new resource on three years' notice beginning in the 2024/25 heating season." [54]

Q. What do you conclude based on this information?

A. I conclude that the facility will operate at reduced capacity for most, if not all, of the MYRP.

Q. What do you recommend?

A. I recommend the commission remove from natural gas revenue requirement the 24 percent (16,000/66,000 MMCFD) of the facility that is not used and useful for ratepayers.

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[53] McGuire, Exh. CRM-12.
[54] *In re Integrated Resource Plan of PSE*, Docket UE-200304, PSE's 2021 Final Integrated Resource Plan, 9-25 (Apr. 1, 2021).

Q. How does your recommendation impact revenue requirement?

A. Staff includes a gross plant amount for Tacoma LNG of $181.4 million in its Adjustment 11.33, which is $58.0 million less than the $239.4 in gross plant PSE included in its Adjustment 11.33. Relative to PSE's revenue requirement calculation, Staff's recommendation to reduce the level Tacoma LNG gross plant included in rates via Adjustment 11.33 reduces revenue requirement by approximately $6.2 million in 2023, $6.1 million in 2024, and $6.0 million in 2025.[55]

3. Energize Eastside (Adjustment 6.33)

Q. What does Staff Witness Nightingale recommend with respect to Energize Eastside that impacts pro forma plant?

A. Staff Witness Nightingale recommends adjusting plant balances to reflect a delay in the anticipated in-service date for the facility that PSE reported in response to discovery.

Q. What is the revenue requirement impact associated with Witness Nightingale's recommendation on Energize Eastside?

A. Relative to PSE's as filed Adjustment 6.33 (which does not account for the delay in the anticipated in-service date), Staff's adjustments reflecting the delay reduce revenue requirements via Adjustment 6.33 by approximately $3.3 million in 2023

[55] McGuire, Exh. CRM-8 at 8:1.

and $2.2 million in 2024, and increases revenue requirement by approximately $0.1 million in 2025.[56]

4. Solar and Storage DERs (Adjustment 6.31)

Q. What does Staff Witness Rector recommend with respect to solar and storage DERs that impacts pro forma plant Adjustment 6.31?

A. Staff witness Rector recommends removing from revenue requirement all costs associated with (a) solar and storage DERs identified in PSE's CEIP,[57] and (b) PSE's storage demonstration project.[58]

Q. What is the revenue requirement impact associated with Witness Rector's recommendation regarding the plant-related costs PSE included in its case related to the solar and storage DERs identified in PSE's CEIP?

A. Staff's removal from Adjustment 6.31 of the solar and storage DERs in question reduces electric revenue requirements by approximately $1.0 million in 2023, $3.5 million in 2024, and $7.9 million in 2025.[59]

Q. What is the revenue requirement impact associated with Witness Rector's recommendation regarding the costs associated with PSE's storage demonstration project?

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[56] McGuire, Exh. CRM-8 at 7:2.
[57] Rector, Exh. ASR-1T at 38:16-22.
[58] Rector, Exh. ASR-1T at 57:19.
[59] McGuire, Exh. CRM-8 at 7:3

A. Staff's removal from Adjustment 6.31 of the costs associated with PSE's storage demonstration project reduces electric revenue requirements by approximately $0.5 million in 2023, $1.2 million in 2024, and $2.8 in 2025.[60]

5. Overall Recommendations on Pro Forma Plant Adjs. 6.31-6.34 electric) and 11.31-11.34 (gas)

Q. Can you please summarize the combined impact on revenue requirement of Staff's various recommendations pertaining to pro forma plant Adjustments 6.31-6.34 and 11.31-11.34?

A. Yes. Relative to PSE's as-filed Adjustments 6.31-6.34, Staff's electric Adjustments 6.31-6.34 – which include the impacts of witness McCullar's recommendation on depreciation accrual rates, witness Nightingale's recommendation on Energize Eastside, and witness Rector's recommendations on solar and storage DERs – reduce electric revenue requirement by approximately $9.5 million in 2023, $15.6 million in 2024, and $23.2 million in 2025.[61]

Relative to PSE's as-filed Adjustments 11.31-11.34, Staff's natural gas Adjustments 11.31-11.34 – which include the impacts of witness McCullar's recommendation on depreciation accrual rates and my recommendation on Tacoma LNG – reduce natural gas revenue requirement by $10.1 million in 2023, $12.5 million in 2024, and $13.8 million in 2025.[62]

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[60] McGuire, Exh. CRM-8 at 7:4
[61] McGuire Exh. CRM-8 at 4:31-34.
[62] McGuire Exh. CRM-8 at 6:31-34.

F. Tacoma LNG upgrade and deferral – Adj. 11.48 (G)

Q. Which Staff witness addresses natural gas Adjustment 11.48 – Tacoma LNG upgrade and deferral?

A. I address PSE's Adjustment 11.48. More specifically, I address the deferral balance associated with the deferred *return on* PSE's investments in distribution system upgrades that connect the Tacoma LNG facility to PSE's distribution system.

Q. Why has PSE been deferring amounts related to its investments in the Tacoma LNG distribution system upgrades?

A. In PSE's 2019 GRC, the Commission authorized PSE to defer costs associated with the Tacoma LNG distribution upgrades.[63] PSE had sought to recover those investments in rates in the 2019 GRC, but at that time the Tacoma LNG facility was not yet in service so the distribution system upgrades made for the purpose of supporting the Tacoma LNG facility were not yet used and useful to ratepayers.[64]

Q. What is PSE seeking to recover in this case through its Adjustment 11.48?

A. PSE is requesting recovery of both the depreciation expense and the return on the distribution upgrades the Company will have deferred for the period after rates became effective in its 2019 general rate case through December 31, 2022.

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[63] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 & UG-190530 Order 8, at ¶ 177 (July 8, 2020).
[64] *Id.* at ¶ 684.

Q. Which of PSE's requests to recover deferral balances does Staff contest?

A. Staff contests PSE's request to recover the deferred return on investment.

Q. Did the Commission authorize PSE to defer a return on the distribution upgrades?

A. Not explicitly, no. The Commission stated only that PSE should be allowed to defer the "costs" associated with the upgrades.[65] It is not clear whether the "costs" contemplated included a return on the Company's investment.

Q. What is the cumulative return deferral balance in question, and what is the amortization expense PSE included its revenue requirement calculation?

A. As of December 31, 2022, PSE estimates the cumulative balance for the return deferral will be $4.7 million, and the annual amortization expense PSE included in its Adjustment 11.48 – corresponding to a three-year amortization of the deferral balance – was $1.7 million.

Q. Should PSE be allowed to recover the deferred return on its distribution system upgrades?

A. No. Setting aside the question of whether PSE was even granted deferred accounting treatment for a return on the Tacoma LNG distribution upgrades, recovery of the return deferral is not appropriate.

[65] *Id.* at ¶ 743.

Q. Why is it not appropriate to grant PSE recovery of the deferred return on investment?

A. Most importantly, PSE was deferring a return on its investment when the facility was not yet used and useful to Washington ratepayers. Granting recovery of returns on investment that were deferred when the facility was not used and useful to ratepayers is tantamount to allowing the facility to be included in rate base when it was decidedly not used and useful.[66] At the conclusion of PSE's 2019 GRC, the Commission affirmed, unequivocally, that "the Tacoma Liquefied Natural Gas Plant is not yet in service, and is thus not yet used and useful."[67]

Q. Are there any other reasons the Commission should deny PSE recovery of the return deferral?

A. Yes. Authorizing recovery of the deferred *depreciation* expense alone would provide meaningful benefit to the Company that, absent said authorization, the Company would not have received. When the Commission determined in PSE's 2019 GRC that it was not yet appropriate to include the distribution upgrades (including the depreciation expense) in rates, it could have very easily stopped there, thus requiring PSE to file for cost recovery only after the Tacoma LNG facility was in service. But the Commission took the extraordinary action of allowing PSE to defer costs associated with distribution upgrades, even though PSE's request for cost recovery was premature. And now in this case PSE seeks recovery of the deferred

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[66] *See People's Org. for Wash. Energy Res. v. Wash. Utils. & Transp. Comm'n*, 104 Wn.2d 798, 809-10, 711 P.2d 319 (1985) (explaining rate base/rate of return ratemaking).

[67] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 & UG-190530 Order 8 at ¶ 684.

depreciation expenses, and to the extent the Commission grants recovery of those deferred depreciation expenses (which Staff does not contest), PSE will be much better off than had it waited until after the facility was in service to seek rate recovery.

In short, granting recovery of the deferred depreciation expense alone already is a decision highly favorable to PSE as it provides the Company with recovery of expenses that the Commission had determined were not appropriate to include in rates, which the Company would not have been provided under standard ratemaking treatment. Granting recovery of the deferred return on investment on top of granting recovery of the depreciation deferral would be decidedly generous to the utility and unfair to the ratepayers who already would be paying for the depreciation deferral in addition to the depreciation expense and the return on rate base that would be included in rates going forward.

Q. What do you recommend regarding PSE's request to recover the return deferral through amortization expense embedded in Adjustment 11.48?

A. I recommend the Commission disallow recovery of the return deferral and, accordingly, remove from Adjustment 11.48 the amortization expense associated with the return deferral.

Q. What is the revenue requirement impact associated with your recommendation to remove amortization of the return deferral from Adjustment 11.48?

A. Relative to PSE's Adjustment 11.48, Staff's Adjustment 11.48 – which removes the annual amortization expense associated with the return deferral – reduces natural gas revenue requirement by approximately $1.6 million for each year of the MYRP. [68]

G. Tacoma LNG plant deferral – Adj. 11.50 (G)

Q. Which Staff witness addresses natural gas Adjustment 11.50 – Tacoma LNG plant deferral?

A. I address PSE's Adjustment 11.50. More specifically, I address the deferral balance associated with the return on the Tacoma LNG facility PSE has been recording since the facility was placed in service in early 2022.

I also address the indirect effect on the depreciation deferral embedded in Adjustment 11.50 of my recommendation to reduce gross plant for the Tacoma LNG facility by 24 percent in Adjustment 11.33 (discussed above).

Q. Why has PSE been deferring amounts related to its investments in the Tacoma LNG facility?

A. On November 24, 2021, PSE filed a petition for deferred accounting treatment for PSE's share of costs associated with the Tacoma LNG facility in Docket UG-210918.[69] In its petition, PSE requested deferred accounting treatment for depreciation expense, operating expenses, and return on plant.[70] That accounting

[68] McGuire, Exh. CRM-8 at 8:8
[69] Docket UG-210918, Puget Sound Energy Petition for an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility (November 24, 2021).
[70] *Id.*, at 2 ¶ 5.

petition is still pending, and on May 12, 2022, the docket was consolidated with the general rate case dockets in this proceeding.[71]

Q. What is PSE seeking to recover in this case through its Adjustment 11.50?

A. PSE is requesting recovery of the cumulative balances related to deferred depreciation expense, deferred O&M, and deferred return on the Tacoma LNG facility for the period beginning with the facility was placed in service through December 31, 2022.

Q. When was the Tacoma LNG facility placed in service?

A. The Facility was placed in service on February 1, 2022.

Q. Which of PSE's requests to recover deferral balances does Staff contest?

A. Staff contests PSE's request to recover the deferred return on investment which will have accumulated only during the pendency of this proceeding.

Q. What is the cumulative return deferral balance in question, and what is the amortization expense PSE included its revenue requirement calculation?

A. As of December 31, 2022, PSE estimates the cumulative balance for the return deferral will be $14.2 million. PSE included an annual amortization expense of $3.5 million in its Adjustment 11.50,[72] corresponding to a four-year amortization of the deferral balance.

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[71] Dockets UE-220066 & UG-220067 (*Consolidated*), and UG-210918, Order 14/01 (May 12, 2022).
[72] Free, Exh. SEF-11, at 50:24

Q. Should PSE be allowed to recover the deferred return on its investment in the Tacoma LNG facility?

A. No. Granting recovery of the return deferral is unwarranted.

Q. Why is granting recovery of the return deferral unwarranted?

A. PSE filed its deferred accounting petition on November 24, 2021, approximately two months before it filed a general rate case on January 31, 2022. In its petition PSE requests deferred accounting treatment for depreciation expense, operating expense, and a return on its investment – all standard costs for which a utility would seek recovery through a general rate case. But rather than treat these as standard costs that the Company simply would seek to recover through this general rate case, PSE asks the Commission to treat these as extraordinary costs that must be given special ratemaking treatment.

The facility was placed in service on February 1, 2022, which is after PSE filed this rate case, and which is a date that fits squarely within the period for the Company's "gap year" pro forma adjustments. The Company has indeed included the facility's costs in revenue requirement through its pro forma Adjustment 11.33, but through its requests to defer prior period costs and then to recover the associated deferral balances, PSE seeks to include in customer rates amounts that exceed the annual costs PSE incurs for the facility. It is not clear to Staff why ratepayers in 2023-2025 should be required to pay for more than their share of the facility's costs.

While Staff is unconvinced that deferred accounting for depreciation, O&M, and return on plant – let alone recovery of the associated deferral balances – is warranted, Staff at this point is only contesting PSE's request for recovery of the deferred return on plant PSE estimates it will book in 2022.

Q. What do you recommend regarding PSE's request to recover the return deferral through amortization expense embedded in Adjustment 11.50?

A. I recommend the Commission disallow recovery of the return deferral and, accordingly, remove from Adjustment 11.50 the associated amortization expense.

Q. What is the impact of your recommendation to disallow recovery of the return deferral on Adjustment 11.50?

A. Relative to PSE's as-filed Adjustment 11.50, my recommendation to disallow recovery of the Tacoma LNG return deferral reduces the annual amortization expense in Adjustment 11.50 by $5.1 million[73] and decreases revenue requirement by $5.3 million for each year of the MYRP.[74]

Q. What do you recommend regarding the depreciation deferral embedded in Adjustment 11.50?

A. Consistent with my recommendation regarding the Tacoma LNG plant balances embedded in PSE's pro forma plant Adjustment 11.33 (discussed in Section V.B, below), I recommend the Commission adjust the depreciation deferral balance to remove the deferred depreciation expense associated with the 24 percent of the facility that is not used and useful.

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[73] *See* McGuire, Exh. CRM-7 at 34:40, as compared to Free, Exh. SEF-11 at 33:40.
[74] McGuire, Exh. CRM-8 at 8:9.

Q. What is the impact of your recommendation to adjust the amortization of the depreciation deferral associated with the 24 percent of the facility that is not used and useful?

A. My recommendation to reduce the depreciation deferral by 24 percent reduces the annual amortization expense in natural gas Adjustment 11.50 by $0.4 million,[75] and reduces rate base by approximately $1.6 million in 2023, $1.2 million in 2024, and $0.7 million in 2025. Relative to PSE's as-filed Adjustment 11.50, Staff's adjustment to the depreciation deferral reduces natural gas revenue requirement by approximately $0.6 million for each year of the MYRP 2023.[76]

Q. What is Staff's overall recommendation on Adjustment 11.50?

A. Relative to PSE's as-filed Adjustment 11.50, Staff's Adjustment 11.50 – which includes the impacts removing the return deferral and reducing the depreciation deferral (and associated amortization expense) by 24 percent – reduces natural gas revenue requirement by approximately $5.8 million for each year of the MYRP.[77]

V. COLSTRIP TRACKER (SCH. 141C)

A. Summary of Recommendations

[75] From $1,447,482 to $1,013,237. *See* Free Exh. SEF-11, at 50:23, and McGuire Exh. CRM-7, at 50:23.
[76] McGuire Exh. CRM-8, at 8:10.
[77] McGuire Exh. CRM-8, page 6:48.

Q. Can you please summarize the decision points for the Commission's consideration of PSE's proposed Colstrip tracker – Schedule 141C?

A. Yes. The decision points on the Colstrip tracker are as follows:

- Approve or reject PSE's proposed tracking mechanism which includes costs (and cost offsets) beyond D&R.
- Allow or disallow recovery of the Dry Ash Waste Disposal System, the purpose of which is to extend the life of Colstrip Units 3-4 beyond 2025.
- Approve or reject PSE's request to amend the prioritization of PTCs for use in offsetting D&R and unrecovered plant balances.
- Determine a revenue requirement (and rates) for Schedule 141C – Colstrip tracker for 2023.

Q. Can you please summarize your recommendations with respect to the decision points you identify above?

A. Yes. My recommendations on the decision points identified above are as follows:

- Approve PSE's proposed tracking mechanism.
- Disallow recovery of the Dry Ash Waste Disposal System.
- Approve PSE's request to amend the prioritization of PTCs.
- Order PSE to submit revised Schedule 141C tariff rates reflecting a 2023 revenue requirement of $50,457,000.[78]

[78] McGuire, Exh. CRM-2 at 1:31.

B. Proposed Colstrip Tracking Mechanism

Q. Can you please summarize the Colstrip tracker PSE proposes in this case?

A. Yes. PSE proposes a tracking mechanism that would capture – and allow PSE to recover – all going-forward costs associated with Colstrip Units 1-4, except for variable power costs and transmission related costs.[79] In addition to decommissioning and remediation (D&R) costs, PSE's proposed Schedule 141C tracker rates would include ongoing expenses (including depreciation, O&M, and amortization of unrecovered plant balances), taxes (including EDIT and treasury grant amortization), and return on rate base.[80]

Q. What is the purpose of PSE's electric Adjustment 6.53?

A. Adjustment 6.53 removes from the electric base rate revenue requirement calculation all of the Colstrip-related items PSE proposes to recover through Schedule 141C.

Q. Do the proposed tracker rates for 2023 include investments PSE expects to make in 2023?

A. No. PSE's proposed tracker rates for 2023 includes all costs in 2023 associated with plant additions through December 31, 2022. Post-2022 Colstrip capital additions would be included in Schedule 141C tracker revisions in future years.

[79] Free, Exh. SEF-18 at 2:4-6
[80] *Id.*, at 2:7-3:3.

Q. Does Staff support PSE's proposed Colstrip tracking mechanism?

A. In concept, yes. However, as explained in further detail below, PSE proposes to include in the Colstrip tracker certain costs that ratepayers should not be on the hook for, such as costs associated with life-extending investments in Colstrip Units 3-4.

But with respect to the Colstrip tracking mechanism itself, Staff believes that including all Colstrip-related costs (and cost offsets) in an annually updated tracker would allow for greater transparency into costs PSE incurs annually for the facility, a greater ability for parties to review those costs and bring concerns to the Commission's attention, and a greater degree of ratemaking flexibility if circumstances change at the facility.

Q. Is PSE's proposal to recover D&R costs through a tracker consistent with the requirements of CETA?

A. Yes. Recovery of D&R costs through a tracking and true-up mechanism is consistent with the statutory language of CETA which states that "the Commission shall allow in electric rates all decommissioning and remediation costs prudently incurred by an investor-owned utility for a coal-fired resource."[81] Without a tracking and true-up mechanism it is not clear to Staff how the Commission would ensure that all D&R costs – and ultimately no more than the amount it deems prudent and no less than the amount the utility prudently incurs – are recovered through rates. The Commission recognized this need when in its final order in PSE's 2019 general rate case the

[81] RCW 19.405.030(1)(b).

Commission ordered PSE to propose a tracker for Colstrip D&R costs that complies with CETA as part of its next general rate case filing.[82]

Q. Is PSE's proposal to recover costs beyond D&R costs (such as depreciation expense and return on rate base) through a tracker consistent with the requirements of CETA?

A. Yes, although CETA does not necessitate use of a tracking and true-up mechanism for the recovery of costs beyond D&R. PSE's reliance on the language of CETA to justify including all costs – not just D&R costs – in the tracker is misplaced. This is because the provision of CETA that PSE uses to justify its proposal pertains only to the recovery of undepreciated plant balances *for plant retired from service*.[83] PSE includes in its proposed tracker going-forward costs associated with Colstrip Units 3-4 which, of course, have not been retired.

Nevertheless, Staff recommends that the Commission approve the catch-all mechanism PSE proposes. The necessity of a tracking and true-up mechanism for Colstrip D&R costs combined with the administrative convenience of having all Colstrip-related costs and cost offsets tracked through a single tariff schedule weighs in favor of approving PSE's proposed tracking mechanism.

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[82] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-190529, Order 08 at ¶ 424-30.
[83] RCW 19.405.030(3) ("The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that has been retired from service…") (emphasis added).

C. Dry Ash Waste Disposal System for Colstrip Units 3-4

Q. Does PSE include any life-extending investments in Colstrip Units 3-4 in its proposed tracker rates?

A. Yes. However, given that PSE has filed tariff sheets for Schedule 141C only for RY1 (2023), the only life-extending investment in Colstrip PSE includes in its proposed tracker rates are the investments in the dry ash waste disposal system. PSE's revenue requirement includes recovery of investments in the dry ash waste disposal system the Company made between 2019 and 2022. The life-extending investments in Colstrip PSE plans to make in 2023 and beyond will be subject to review when PSE files for revised Schedule 141C rates for 2024 and beyond. PSE's planned investments in life-extending plant between 2023 and 2025 are discussed in further detail in Section V.E, below.

Q. Regarding the Dry Ash Waste Disposal System specifically, what is the magnitude of the investment PSE made between 2019 and 2022?

A. PSE's annual transfers to plant for the Dry Ash Waste Disposal System are shown in Table 4, below.

Table 4. Dry Ash Waste Disposal System – Annual and Cumulative Plant Additions.[84]

Year	Annual Amount	Total EOP Balance
2019	$64,820	$64,820
2020	$1,285,579	$1,350,399
2021	$6,279,500	$7,629,899

[84] McGuire Exh. CRM-13.

2022	$2,150,000	$9,779,899
TOTAL	**$9,779,899**	

Q. What are Staff's concerns with respect to PSE including the dry ash waste disposal system in its proposed 2023 tracker rates?

A. Only investments that are used and useful for service to Washington may be included in rates, and there is no way around the fact that PSE's investment in the Colstrip dry ash waste disposal system was made for the purpose of extending the life of the facility beyond 2025—for a facility that ratepayers will not use beyond 2025. The Commission has observed that the used and useful standard can be met only when a utility demonstrates that an investment "provides quantifiable direct or indirect benefits to Washington commensurate with its cost."[85] PSE's investment in the dry ash waste disposal system cannot meet this standard because the benefits the investment provides – *i.e.*, power production from Colstrip Units 3-4 beyond 2025 – are benefits that will never accrue to Washington ratepayers.[86]

Q. Has the Commission addressed investment in the dry ash waste disposal system in any other proceeding?

A. Yes. In Avista's 2020 GRC, the Commission declined to allow the dry ash waste disposal system into rates. In that case, the Commission agreed with Staff that the

[85] RCW 80.04.250; *Wash. Utils. & Transp. Comm'n v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Dockets UE-050684 & UE-050412, Order 04/03, 27-28 at ¶ 68 (Apr. 17, 2006).
[86] In addition to not being used and useful to Washington ratepayers, PSE's decisions to make major life-extending capital investments in Colstrip Units 3 and 4 (like Dry Ash) are likely imprudent given the mandates in CETA. RCW 19.405.030 ("On or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. . . .").

investment in a dry ash waste disposal system "is not [a] routine capital maintenance measure and… absent a showing by Avista that it is *not* life-extending, we are unconvinced that it should be allowed in rates."[87]

Q. Does Staff recommend allowing the dry ash disposal system into PSE's rates?

A. No. PSE did not address the question of whether the investment was life extending, let alone make a showing that it was not. As such, and consistent with the Commission's treatment of Avista in the 2020 GRC, the dry ash waste disposal system should not be allowed in PSE's rates.

Q. The Commission excluded the dry ash disposal system from Avista's rates because Avista had previously agreed to not support capital expenditures that would extend Colstrip's operational life beyond 2025, did it not?

A. While the Commission did point to that term in the settlement agreement in the Avista case,[88] the Commission's decision appeared to lean on its findings that the costs were not known and measurable and that the investments were made for the purpose of extending the life of Colstrip Units 3-4.[89]

Q. Why does PSE believe it was necessary to invest in a dry ash waste disposal system for Colstrip Units 3-4?

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[87] *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-200900 & UG-200901, Order 08 at ¶ 279 (emphasis in original).
[88] *Id.* (citing *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-190334, UG-190335 & UE-190222, Final Order 09 at 19, ¶ 51 (Mar. 25, 2020)).
[89] *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-200900 & UG-200901, Order 08 at ¶ 279.

A. PSE claims that the investment was necessary to comply with the terms of a settlement that the owners of Colstrip entered into with Sierra Club, the Montana Environmental Information Center ("MEIC"), and National Wildlife Federation ("NWF")—referred to as the Administrative Order on Consent ("AOC")--- which required the owners of Colstrip to "[C]onvert to a 'non-liquid' disposal system for CCR material generated by Colstrip Units 3 and 4's scrubbers no later than July 1, 2022."[90]

Q. Does Staff find this to be a persuasive argument for recovering the costs of the investment from ratepayers?

A. No. The fact that PSE entered into an agreement to install a life-extending capital additions by a date certain does not make the investment used and useful for Washington ratepayers. As stated above, the benefits of the investment to Washington ratepayers – i.e., zero – are not commensurate with the costs PSE seeks to include in rates.

Furthermore, the Legislature, as codified in CETA, has instructed this Commission to move away from coal-fired generation—not to facilitate regulated utilities continued major investment in coal-fired generation.

Q. Could the owners of Colstrip have chosen a course of action other than moving forward with the investment in the dry ash waste disposal system?

[90] Roberts, Exhibit RJR-27 (Colstrip Administrative Order on Consent).

A. It appears so, yes. As the Commission took note of, the plaintiffs to the AOC "apper[ed] amenable to discussions about moving or removing the deadline for completing Dry Ash. On February 19, 2021, Sierra Club, MEIC, and NWF sent a letter to Colstrip's co-owners offering to discuss extending the timeline for completing the dry ash waste disposal system in exchange for a definitive closure date for Colstrip Units 3 and 4."[91] However, the record in the current case is void on the outcome of any discussions between these parties and rationale on why PSE decided to move forward with the investment.[92]

D. PTC Prioritization

Q. Can you please summarize the existing priority of Colstrip-related costs that PSE can offset with monetized PTCs?

A. Yes. Order 08 of PSE's 2017 GRC established the order of priority by which PSE shall utilize monetized PTCs.[93] That priority is as follows:

1. To fund community transition planning funds of $5 million for the benefit of citizens in Colstrip, Montana;
2. To recover unrecovered plant balances for Colstrip Units 1 through 4; and
3. To fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 through 4.

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[91] *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-200900 & UG-200901, Order 08 at ¶ 278.
[92] PSE noted only that Northwestern Energy indicated they would not be willing to discuss a closure date for Units 3 and 4. Roberts, Exh. RJR-1T at 98:1-13.
[93] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-170033 & UG-170034, Order 08, 40-41 ¶ 112, 51 ¶ 138 (Dec. 5, 2017).

Q. How does PSE request that the existing priority be modified?

A. PSE proposes to modify the priority by merging items 2 and 3, above. That is, PSE requests that D&R costs be given the same level of priority as unrecovered plant balances when determining which costs can be offset with monetized PTCs. This modification to the priority schedule, PSE argues, would allow the Company to begin using monetized PTCs now to offset D&R costs now rather than waiting until Colstrip Units 3-4 are removed from service to apply monetized PTCs against unrecovered plant balances.[94]

Q. Does Staff support PSE's request to consolidate items 2 and 3 of the existing priority schedule?

A. Yes.

Q. Why does Staff support consolidation of items 2 and 3 of the existing priority schedule?

A. Consolidating items 2 and 3 of the existing priority schedule – in effect, allowing PSE to reduce the balance of D&R costs it must recover through tracker rates – has the effect of reducing the Schedule 141C tracker rates for the next three years. Staff believes it is important to mitigate the rate impact of Colstrip-related costs over the period 2023-2025 in particular because ratepayers over that period already are carrying the burden of paying for the full remaining book value of Colstrip Units 3-4 over a mere three years.

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[94] Free, Exh. SEF-18 at 6:17-7:2.

Q. The existing priority schedule was established via Commission approval of a settlement in PSE's 2017 GRC. Are the parties to the Settlement in the 2017 GRC also parties in the current GRC?

A. Mostly, yes, although one party to the Settlement has not intervened in the current proceeding. The Settlement was entered into by and between PSE, Staff, ICNU, NWEC/RNP/NRDC, TEP, Sierra Club, FEA, Kroger, the State of Montana, and NWIGU. Of these parties, only the State of Montana is not represented in the current proceeding.[95] However, the terms of the Settlement PSE requests to amend pertain to ratemaking and regulatory accounting and do not pertain to the interests of the State of Montana.

E. Schedule 141C Rates

Q. What revenue requirement does PSE calculate for its Schedule 141C rates for 2023?

A. PSE's requested revenue for its proposed Schedule 141C Colstrip tracker for 2023 is $53,883,000.[96]

Q. What is Staff's recommended revenue requirement for the Schedule 141C rates for 2023?

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[95] ICNU and NWIGU subsequently merged and is now named Alliance for Western Energy Consumers (AWEC), which is an intervenor in this proceeding. Fred Meyer and QFC, members of the Kroger family, have intervened as a single party in this proceeding. And while NWEC, RNP, and NRDC intervened as a single party in the 2017 GRC, only NWEC has intervened in this proceeding.

[96] Free, Exh. SEF-3 at 1:31.

A. Staff recommends a revenue requirement of $50,457,000, or a reduction of approximately $3.4 million relative to PSE's requested revenue requirement. The difference in revenue requirement is attributable to Staff's removal of the costs associated with the dry ash waste disposal system and Staff's recommended ROR.

Q. Does PSE provide its revenue requirement projections for Schedule 141C rates for 2024 and 2025?

A. Yes. Although PSE did not file tariff sheets for Schedule 141C for 2024 or 2025, PSE nevertheless presents projected revenue requirements for the Colstrip tracker of an additional $3.6 million in 2024 and another $22.4 million in 2025.[97]

Q. Does Staff have recommendations for the Schedule 141C revenue requirements for 2024 and 2025?

A. Not formally, no. PSE's proposed Schedule 141C is a tracking and true-up mechanism which would require annual tariff revisions, so PSE did not file Schedule 141C tariff sheets in this docket with effective dates for 2024-2025. Therefore, the costs PSE would seek to recover in those years through Schedule 141C are not at issue in this proceeding. Accordingly, Staff does not have a formal recommendation on the Schedule 141C revenue requirements for those years. Staff will develop a position on those revenue requirements when the Company files for revised rates for 2024 and 2025.

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[97] *Id.*

Q. Did Staff make any adjustments to the Schedule 141C revenue requirements PSE projected for 2024 and 2025.

A. Yes. Although the Schedule 141C rates for 2024 and 2025 technically are not at issue in this proceeding, PSE nevertheless presented its projected Schedule 141C revenue requirements for 2024 and 2025. As PSE's projected Schedule 141C revenue requirements for 2024 and 2025 contain costs that likely will be contested, Staff was uncomfortable including PSE's unchallenged projections in Staff's revenue requirement exhibit.

Q. What are the costs that likely will be contested that PSE included in its revenue requirement projections for Schedule 141C for 2024-2025?

A. In addition to PSE's investment in the dry ash waste disposal system (which Staff is formally contesting in this proceeding), PSE also includes in its projected 2024 and 2025 tracker rates costs associated with investments in a superheat section replacement and a condenser tube replacement. PSE also includes a large ($5.6 million) year-over-year increase in major maintenance amortization expense in its projected 2025 tracker rates.

Q. Please describe the issues with PSE's investments in the condenser tube replacement and the superheat section replacement?

A. These investments have the same fundamental issue as the dry ash waste disposal system; they are both investments made to extend the life of Colstrip Units 3-4. Investments made for the purpose of extending the life of Colstrip Units 3-4 beyond

2025 do not provide benefit to Washington ratepayers and thus do not meet the Commission's used and useful standard.

Q. Please describe the issues with the major maintenance amortization expense in 2025.

A. PSE identifies an major maintenance amortization expense for Colstrip Units 3-4 of $9.3 million, which is approximately $5.8 million higher than the amount the Company projects for 2024 ($3.5 million) and approximately $7.3 million higher than the amount it projects for 2023 ($2.0 million).[98] It appears that large increase in major maintenance amortization expense in 2025 is due to PSE's intention to amortize major maintenance expense over one year (2025) rather than amortize the costs over multiple years, as is standard practice. Setting aside the issue of whether it is appropriate to recover from ratepayers any of the costs for major maintenance undertaken in 2025 (given that Washington ratepayers will not receive power from the facility beyond 2025), it is not reasonable or consistent with standard practice to amortize major maintenance expense over one year.

Q. How did Staff adjust PSE's projected 2024-2025 revenue requirements for Schedule 141C.

Staff adjusted PSE's projected Schedule 141C revenue requirements for 2024 and 2025 to reflect (a) removal of the costs of life-extending investments (i.e., the dry ash waste disposal system, the superheat section replacement, and the condenser tube

[98] McGuire, Exh. CRM-14.

replacement), and (b) removal of the increase in major maintenance expense in 2025. Staff's Schedule 141C revenue requirement also includes the impact of Staff's recommended ROR on the return component of the revenue requirement.

Q. How do Staff's adjustments impact PSE's projected Schedule 141 revenue requirements for 2024-2025?

For 2024, Staff preliminarily calculates a projected Schedule 141C revenue requirement of $53.5 million which is $4.0 million lower than PSE's projection of $57.5 million. For 2025, Staff preliminarily calculates a projected Schedule 141C revenue requirement of $64.1 million which is $14.8 million lower than PSE's projection of $79.9 million.

F. If the Colstrip Tracker is Rejected

Q. Is there anything the Commission should be aware of if it rejects PSE's proposed tracker?

A. Yes. If the Commission rejects PSE's proposed tracker, the Commission should be aware that the Colstrip costs PSE had included in the tracker would be moved into the base rate revenue requirement calculation.[99] While the costs PSE intends to recover in the 2024-2025 tracker rates technically aren't at issue in this case, if those costs were to be moved into the base rate revenue requirement calculations they suddenly would be at issue in this case.

[99] PSE removed Colstrip-related costs from the base rate revenue requirement calculation through electric Adjustment 6.53.

This could be particularly problematic for the Colstrip costs PSE projects for its 2024 and 2025 tracker rates, which include the life-extending plant (i.e., the dry ash waste disposal system, the superheat section replacement, and the condenser tube replacement) and the major maintenance expense in 2025. The Commission should be aware that if it rejects the proposed Schedule 141C tracker the Commission will need to determine in this proceeding whether to disallow recovery of those costs in PSE's base rates in 2023, 2024, and 2025.

If the Commission for whatever reason determines that it must make a decision in this proceeding on the recovery of Colstrip costs PSE included in its projected 2024-2025 Schedule 141C rates, the Commission should disallow rate recovery of the three life-extending investments discussed above as well as the incremental major maintenance expense PSE projects it will incur in 2025. Not only will those costs not provide commensurate benefits to ratepayers, but the evidentiary record pertaining to these costs is entirely undeveloped. PSE provided no testimony on the major maintenance expense in 2025, and provided no capital justification or testimony on the superheat section replacement or the condenser tube replacement, with the exception of a single page that concluded by saying: "The superheat project was proposed by Talen MT for the 2020 major maintenance event at Colstrip Unit 4. However, the Owners did not approve the project at that time."[100]

Q. Does this conclude your testimony?

A. Yes.

[100] Roberts, Exh. RJR-1CT at 93.