Exh. JL-1CT
Docket UE-200115
Witness: Jing Liu
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of **PUGET SOUND ENERGY** **For an Order Authorizing the Sale of All of Puget Sound Energy's Interests in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System**	**DOCKET UE-200115**

TESTIMONY OF

Jing Liu

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Cost-Benefit Analysis for the Sale of Unit 4;
Accounting Treatments;
Suggested Conditions in Case of Approval

October 2, 2020

CONFIDENTIAL PER PROTECTIVE ORDER - REDACTED VERSION

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jing Liu, 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 jing.liu@utc.wa.gov.

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

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as a regulatory analyst in the Energy Section of the Regulatory Services Division.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since 2008.

Q. Please state your qualifications to provide testimony in this proceeding.

A. I hold a Bachelor's degree in English Language and Literature, a Master of Arts degree in organizational communication, and a Master of Science degree in communication technology and policy from Ohio University. I completed four years of doctoral study in public policy at Ohio State University. I worked as a graduate research associate at the National Regulatory Research Institute (NRRI) from 2005 to 2007. I worked in the telecommunications section of the Commission between

2008 and 2014 where I was responsible for developing and implementing telecommunications universal service policies and designating and certifying Eligible Telecommunications Carriers in Washington. I have been working in the Energy Regulation Section of the Commission since 2014. In this role, I have been the lead analyst across a number of topics, including decoupling, temperature normalization, low income bill assistance, purchased gas adjustments, gas pipeline cost recovery mechanisms, depreciation studies, revenue requirement, and attrition models.

Q. Have you testified previously before the Commission?

A. Yes. I provided testimony to the Commission in proceedings addressing United Telephone Company of the Northwest Inc.'s intrastate access charges (UT-081393), the acquisition of Verizon Northwest, Inc. by Frontier Communications Corporation (UT-090842), the acquisition of Qwest Corporation by CenturyLink, Inc. (UT-100820), Frontier Communications Northwest, Inc.'s petition for competitive classification (UT-121994), Avista Corporation's General Rate Case (GRC) (UE-160228/UG-160229), Puget Sound Energy's GRCs (UE-170033/UG-170034 and UE-190529/UG-190530), Avista's depreciation study (Dockets UE-180167/UG-180168), Cascade Natural Gas's GRC (UG-170929) and Northwest Natural Gas's GRC (UG-181053).

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is purpose and scope of your testimony?

A. The purpose of my testimony is to: (1) respond to PSE's portrayal of the quantifiable net benefits associated with the sale of Colstrip Unit 4, as calculated through PSE Witness Cindy Song's cost-benefit analysis; and (2) respond to PSE Witness Susan Free's proposed accounting and regulatory treatments, which are relevant only if the Commission approves the proposed transfers of property.

Q. Please summarize your conclusions with respect to the quantifiable net benefits of the Unit 4 sale.

A. My evaluation indicates PSE has overstated the quantifiable net benefit that would result from the sale of Unit 4, in large part because PSE uses overstated costs from Talen Montana LLC's (Talen) budget when calculating the cost of continuing operations.

In my testimony, I show that if Talen's estimated costs are replaced with historical average costs for operations and maintenance (O&M) and major maintenance costs, the estimated quantifiable net benefits are substantially smaller. While PSE's cost-benefit analysis produces $33 million estimated net benefits over the next five years with a possibility of negative $[redacted] million, my analysis produces $[redacted] million estimated net benefits over the next five years with a possibility of negative $[redacted] million.

The estimated net benefits produced by my analysis demonstrates the potential for PSE's sale of Unit 4 to result in net cost to ratepayers. However, even the low end of estimated net benefits produced by my analysis would be further eroded if Mid-C prices increase beyond the prices PSE assumed in its elevated Mid-C price scenario.

And here's the kicker – the net benefits estimated through PSE's cost-benefit analysis do not even represent the benefits that would accrue to ratepayers. Because customer rates would not change when the sale closes, the net benefits PSE claims – to the extent they even materialize – would not flow through to ratepayers until after PSE's *next* rate case. The accounting and regulatory treatments proposed by PSE do not remedy this problem.

Q. Please summarize your conclusions and recommendations with respect to the accounting and regulatory treatments proposed by PSE.

A. Staff's recommendation that the Commission deny PSE's proposed transfers of property renders PSE's proposed accounting treatment moot. However, in the event that the Commission finds that the Unit 4 sale is consistent with the public interest and approves the transaction, the Commission should authorize regulatory treatment for the net book value of the facility, as well as for remediation costs, allowing PSE to record unrecovered balances to two separate regulatory asset accounts.

Some elements of PSE's accounting proposals would deprive ratepayers of benefits PSE attributes to the transactions. Specifically, PSE's proposals: (a) would have ratepayers pay for the amortization expense for a Colstrip Unit 4 regulatory asset, even though PSE has available Production Tax Credits (PTCs) to offset that regulatory asset; and (b) would limit ratepayers from sharing the full benefit of avoided O&M expense, and would subject ratepayers to potential price surge under the proposed Colstrip PPAs.

To provide mitigation for these issues, the Commission should deny PSE's request to: (1) use ratepayers' contribution to depreciation expense to offset the Colstrip Unit 4 regulatory asset; (2) use ratepayers' contribution to fixed O&M cost to offset the actual variable costs in the Power Cost Adjustment (PCA) mechanism; and (3) provide no deferral treatment to PSE's avoided costs related to the Colstrip Transmission sale. Instead, the Commission should adopt the accounting and regulatory treatments that Staff recommends as conditions for approval.

Q. Please summarize Staff's recommended conditions if the Commission approves any aspect of PSE's application.

A. Staff's overall recommendation is that the Commission should reject PSE's property transfer applications, for both its interest in Colstrip Unit 4 as well as its interest in the Colstrip Transmission System. Staff also recommends that the Commission decline to pre-approve the Colstrip PPAs in this proceeding, regardless of how it rules on the transfers of property.[1] However, in the event that the Commission approves one or more of the proposed transfers of property, Staff offers several recommended conditions of approval for the Commission's consideration.

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[1] Please see McGuire, Exh. CRM-1T.

Regarding the sale of PSE's ownership interest in Colstrip Unit 4, if the Commission approves the Unit 4 sale, Staff recommends that the Commission do so subject to the following conditions:

1. The Commission should order PSE to use monetized PTCs to offset the unrecovered plant balance of Unit 4.
2. If the Commission authorizes the use of PTCs, the Commission should require PSE to record ratepayers' payment for the Colstrip Unit 4 depreciation expense, which PSE will no longer incur after the sale, as a regulatory liability and pass on to ratepayers at an appropriate time.
3. The Commission should require PSE to book ratepayers' payment for the Colstrip Unit 4 O&M expense, which PSE will no longer incur after the sale, as a regulatory liability and credit to ratepayers at an appropriate time.
4. Ratepayer responsibility for Colstrip PPAs costs should be capped at $[redacted] million annually for purpose of calculating the power cost imbalance under the PCA mechanism and for the revenue requirement calculation in future rate proceedings.
5. The Commission should disallow PSE's recovery in rates of any incremental decommissioning and environmental remediation costs directly attributable to continued operation of Unit 4 after the closure of the Unit 4 sale.
6. The Commission should require PSE to take concrete steps after the Unit 4 sale is closed to work with other Colstrip owners towards the closure of

Colstrip Unit 3 by December 2025, and require PSE to provide the Commission with progress reports and documentation, as my colleague David Gomez details in his testimony.[2]

Regarding the sale of PSE's ownership interest in the Colstrip Transmission System (CTS), if the Commission approves the sale, Staff recommends it do so subject to the following condition:

1. PSE should record ratepayers' payment for the CTS depreciation expense, which PSE will no longer incur after the sale, as well as the return associated with the transmission assets, to a regulatory liability and pass that amount on to ratepayers at an appropriate time. The same condition should apply to the PSE's potential sale of CTS in the future.

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

A. Yes. I prepared Exhibits JL-2C through JL-7.

Exh. JL-2C presents PSE's cost-benefit analysis with the assumption of high market prices.

Exh. JL-3C shows a comparison of Colstrip historical O&M expense as compared to budget, historical expenditures on major maintenance and capital additions.

Exh. JL-4C shows the cost-benefit analysis with Staff's alternative cost assumptions.

[2] Gomez, Exh. DCG-1T, 43–45.

Exh. JL-5C shows a cost-benefit analysis with Staff's alternative cost assumptions and the assumption of high market prices.

Exh. JL-6 shows PSE's response to WUTC Staff Data Request No. 15 on the net book value of PSE's Colstrip Transmission for sale.

Exh. JL-7 shows PSE's response to WUTC Staff Data Request No. 36 on dry ash disposal related remediation cost and O&M.

III. STAFF'S RESPONSE TO PSE'S COST-BENEFIT ANALYSIS

A. Overview Of PSE's Cost-Benefit Analysis

Q. Please briefly describe PSE's cost-benefit analysis.

A. The cost-benefit analysis presented by PSE Witness Song purports to compare PSE's costs on a net present value (NPV) basis roughly from 2021 through 2025 under two scenarios: (1) continuing operations absent the sale of Unit 4; and (2) operations after the sale of Unit 4.[3]

Under the continuing operations scenario, PSE retains its ownership interest in Colstrip Unit 4, and continues to receive a 185 MW share of power from the facility. Under the scenario where PSE has completed the sale of Unit 4, PSE receives a 45 MW share from each of the two separate PPAs (90 MW total) and relies on the spot market to replace the other 95 MW share.

[3] *See* Song, Exh. CLS-1T and CLS-8T. The exact time frame for the analysis is between December 17, 2020 and December 31, 2025.

Q. What does PSE claim its cost-benefit analysis shows?

A. PSE claims that its cost-benefit analysis shows it will be more expensive for PSE to retain its ownership interest in Colstrip Unit 4 than to sell its ownership interest in Unit 4 and obtain an equivalent amount of power supply from a combination of the PPAs and market purchases.

Through its cost-benefit analysis, PSE estimates the sale of Colstrip Unit 4, in conjunction with the PPAs and market purchases, will result in a quantifiable net benefit of approximately $33 million over five years, and approximately $6 million with hedge.[4]

Q. How does the assumption that PSE would hedge its market purchases impact the estimated net benefits of the Unit 4 sale?

A. In PSE's cost-benefit analysis, that assumes a potential hedge for the 95 MW market power purchase, PSE projects that the sale of Unit 4 will produce a net benefit of approximately $6 million over five years.[5] Since there is clearly risk associated with *not* hedging 95 MW of exposure to the spot market, it is reasonable to expect that PSE will hedge a portion or all of the market purchases and, therefore, reasonable to include a hedging assumption in the assessment of the range of possible outcomes.

Q. How do the estimated net benefits change under the high market price scenario?

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[4] Song, Exh. CLS-08 at 8:15–9:2.
[5] Song, Exh. CLS-09C at 1.

A. PSE's projected net benefit from the sale of Unit 4 in its high market price scenario was $[redacted] million without hedging, and a <u>net cost</u> of $[redacted] million with hedging.[6]

Q. Please summarize the total quantifiable net benefits presented by PSE's various scenarios.

A. With its high Mid-C price plus hedging scenario on one end and its low Mid-C price without hedging scenario on the other, PSE presents to the Commission possible net benefits of $33 million, with a possibility of negative $[redacted] million.[7]

B. Staff's Assessment Of PSE's Net Benefit Analysis

1. Problem 1 – Faulty assumptions with large impacts on the net benefit calculation

Q. Does Staff accept negative $[redacted] million to $33 million as a reasonable representation of possible outcomes of the sale of Unit 4?

A. No. As I describe in below, Staff is concerned that certain assumptions PSE uses in its cost-benefit analysis bias the analysis in favor of positive net benefits. Additionally, even without addressing the questionable assumptions, the net benefits PSE claims are tenuous at best.

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[6] Liu, Exh. JL-2C at 8.

[7] Song, Exh. CLS-9C at 1; Liu, Exh. JL-2C at 8.

Q. Please explain how the net benefits PSE claims are tenuous.

A. In PSE's cost-benefit analysis, modest changes in individual assumptions have large impacts on the estimated net benefits, such that with only a couple changes in assumptions the net benefit PSE claims evaporates entirely (i.e., becomes a net cost to ratepayers).

For example, in PSE's high Mid-C price scenario, $[redacted] million in projected net benefits evaporated with a fairly modest increase to projected Mid-C prices.[8] This demonstrates not only that the net benefits PSE claims are tenuous, but also that the net benefits are highly dependent on Mid-C prices staying low. In that same high Mid-C price scenario, and under the assumption that the Company will hedge its market purchases, PSE projects that the Unit 4 sale will result in a negative net benefit (i.e., a <u>net cost</u>).

Q. Please explain your concern that certain assumptions PSE uses in its cost-benefit analysis bias the analysis in favor of positive net benefits

A. Specifically, I have concerns with PSE's assumptions for fixed O&M and major maintenance cost, both of which come from Talen's 2019 budget forecast for 2020 - 2024,[9] and both of which appear to be substantially overstated.

Q. Can you please summarize the cost assumptions PSE uses in its cost-benefit analysis?

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[8] *See* Liu, Exh. JL-2C.

[9] Song, Exh. CLS-1T at 22:15-18. Talen budget as of August 30, 2019.

A. Yes. The following table lists the cost assumptions on an average annual basis that PSE uses in the no-hedging scenario.

Table 1. PSE's Comparison of Continuing Operations and Proposed Sale Scenarios[10]
(Average Annual Cost Rounded in Millions)

	Continuing Operation	Unit 4 Sale + Colstrip PPAs
Fixed O&M	$[redacted]	[redacted]
Major Maintenance	[redacted]	[redacted]
Capital Expenditure	[redacted]	[redacted]
Variable Dispatch Cost	[redacted]	[redacted]
Property Tax	[redacted]	[redacted]
Colstrip PPAs	[redacted]	$[redacted]
Market Purchase	[redacted]	[redacted]
Total	$[redacted]	$[redacted]
Net Savings (Continuing Operation – (Unit 4 Sale + Colstrip PPAs)):		$[redacted]

Q. What do you mean by your statement that the costs in Talen's budget appear to be substantially overstated?

A. To demonstrate that Talen's budget does not provide a reliable indication of the costs that would actually be incurred, I provide a comparison in Exh. JL-3C of the costs in Talen's budget to actual costs. A summary of that comparison is as follows:

- For fixed O&M expense excluding major maintenance, PSE's cost-benefit analysis assumes around $[redacted] million on an annual basis. However, the historical actual O&M expense excluding major maintenance allocated to Colstrip Unit 4 averaged about $[redacted] million,[11] a striking $[redacted] million less annually than what Talen included in its budget. Also, as proof of Talen's

[10] Song, Exh. CLS-9C, at 3 and 4.
[11] Liu, Exh. JL-3C at 1.

chronical overbudgeting, I show that the actual annual fixed O&M expenses between 2016 and 2019 were on average $[redacted] million lower than what Talen included in its budget.[12]

- For major maintenance costs scheduled in 2024 for Unit 4, PSE relied on Talen's budget to estimate its share at $[redacted] million, including $[redacted] million in managerial reserves.[13] In comparison, the average major maintenance for each Colstrip unit from 2015 to 2020 is around $[redacted] million, or just over half of the $[redacted] million derived from Talen's budget.[14]
- For capital additions, PSE assumed about $[redacted] million each year based on Talen's budget. The historical average of actual capital additions from 2009 to 2019 is $[redacted] million with wide variations from year to year, ranging from $[redacted] million to $[redacted] million each year.[15]

Of these cost assumptions, only Talen's budget for capital additions is reasonably close to the historical average. The assumptions for fixed O&M expense and major maintenance costs based on Talen's budget appear to be substantially out of sync with reality.

Q. What is the consequence of using the overstated costs from Talen's budget?

A. PSE's use of the overstated costs from Talen's budget results in an overstated cost of continuing operations which, in turn, has the effect of making post-sale operations

[13] Song, Exh. CLS-09C at 9.
[14] Liu, Exh. JL-3C at 1.
[15] *Id.*

appear less costly in comparison. In other words, using Talen's budget biases the net benefit calculation in favor of the sale.

Q. Did you attempt to estimate the net benefit of the Unit 4 sale using alternative cost assumptions?

A. Yes. Using PSE's cost-benefit model, I assessed the effect of replacing the Talen budget estimates for O&M cost and major maintenance cost with averages of historical actuals. More specifically, I replaced Talen's O&M cost estimate of roughly $[redacted] million annually with $[redacted] million, which was the average annual O&M expense between 2016 and 2019.[16] I also replaced Talen's major maintenance cost estimate of $[redacted] million with $[redacted] million, which was the average annual major maintenance expense between 2015 and 2020.

Using my alternative cost assumptions, the net benefit in PSE's "best case" scenario (i.e., low Mid-C price, no hedging) decreases by $[redacted] million, from $[redacted] million to $[redacted] million. In the hedging scenario, the net benefit also decreases by $[redacted] million, from positive $6 million to negative [redacted] million.[17]

Under the assumption of high Mid-C prices, PSE's expected net benefits of the Unit 4 sale will decrease by about $[redacted] million, from $[redacted] million down to $[redacted] million in the no-hedging scenario, and decrease by about $[redacted] million, from negative

[16] In my modified cost-benefit analysis, I did not change the capital addition cost assumptions because of the large variations in historical capital expenditures. Staff also assumes the base O&M is 90/185 of the overall O&M in the continuing operation scenario without speculating the amount of non-base O&M, a relatively small expense that will be excluded from the PPA payment.
[17] Liu, Exh. JL-4C at 2.

$[redacted] million down to negative $[redacted] million in the hedging scenario.[18] Table 2 provides a summary of these results.

Table 2. Comparison of Net Present Value of Total Savings (in millions)

	PSE		Staff	
	With Hedging	No Hedging	With Hedging	No Hedging
With Normal Market Price	$6	$33	-$[redacted]	$[redacted]
With High Market Price	-$[redacted]	$[redacted]	-$[redacted]	$[redacted]

As shown above, with a change in just two basic assumptions alone, the net savings shrink down to $[redacted] million in five years even in the most optimistic scenario, with no hedging. It translates to $[redacted] million benefit each year, a minuscule amount in relation to PSE's annual power cost in the magnitude of $1.5 billion. If the spot market price happens to be high, the net savings from the deal would further dwindle to $[redacted] million total over 5 years. In the hedging scenario, the total net cost could be as high as $[redacted] million.

Q What does this say about PSE's cost-benefit analysis and the quantifiable net benefits PSE claims will result from the sale of Unit 4?

A. First, it is worth reiterating here the tenuousness of the net benefits PSE claims will result from the sale of Unit 4. Replacing Talen's budget estimates for just two categories of costs (fixed O&M and major maintenance) with an average of

[18] Liu, Exh. JL-5C at 2.

historical actuals reduces the net benefit by $[redacted] million, and assuming a higher than average Mid-C price reduces the net benefit by another $[redacted] million. That is, with just a couple modest changes in assumptions, $[redacted] million of the $33 million (PSE's initial net benefit estimate) evaporates. In the scenario where PSE hedges its market purchases, with the same modest changes in assumptions, the net benefits disappear entirely. Instead, the sale of Unit 4 would result in an $[redacted] million net cost to ratepayers.

My analysis indicates expected net benefits of $[redacted] million, with a possibility of negative $[redacted] million. However, even that negative $[redacted] million fails to capture the risk of even higher Mid-C prices. The Mid-C price forecast PSE assumes for its "high market price" scenario does not reflect the upper limit of possible Mid-C market prices and, as a result, the "high market price" scenario does not capture the true upside risk of 95 MW of exposure to the spot market. Mid-C market prices above those assumed in PSE's cost-benefit analysis would even further erode the net benefits of the sale (or further exacerbate the net cost). Staff witness Andrew Rector discusses the price volatility of the Mid-C energy market in his testimony.[19]

Q What do you conclude from these net benefit calculations?

A. Given the results of my analysis of PSE's net benefit calculations, I cannot conclude with any degree of certainty that the proposed Unit 4 sale will produce a net benefit in terms of cost savings. In fact, my analysis indicates the transactions could very well result in a net cost to ratepayers. With that distinct possibility in mind, I

[19] Rector, Exh. ASR-1CT at 14:20–15:14.

conclude that the Unit 4 sale is inconsistent with the Commission's "no harm" standard (i.e., its public interest standard).

2. Problem 2 – Estimated net benefits are not passed on to PSE's ratepayers

Q. What is your concern regarding ratepayer benefits from the Proposed Transactions?

A. Assuming net benefits of the Unit 4 sale actually materialize (and as I explain in Section B(i)), those benefits will not accrue to ratepayers absent regulatory accounting treatment. However, the request for accounting treatment put forth by PSE Witness Free does not ensure ratepayers will benefit from the reduction or elimination of certain costs associated with PSE's ownership in Colstrip. Those costs consist of: (a) return of and return on PSE's investment, (b) fixed O&M expense, and (c) variable power costs. Until PSE files a GRC, and until new rates from that future GRC go into effect, cost savings will not be passed on to ratepayers. PSE's proposed accounting treatment fails to remedy these issues.

Q. Please explain PSE's proposed accounting treatment for the return of and return on the remaining book value of Colstrip Unit 4 and your assessment.

A. Although the net book value for Colstrip Unit 4 is approximately $85 million, PSE has agreed to sell its ownership interest in the facility for $1.[20] Accordingly, if and

[20] Free, Exh. SEF-5T at 5:21-24.

when the sale closes, PSE will be required to book an $85 million loss on sale. PSE requests that the Commission authorize the Company to book the $85 million loss on sale to a regulatory asset.[21] Booking the $85 million loss on sale to a regulatory asset will allow PSE to (1) recover the $85 million from ratepayers, and (2) earn a return on the $85 million, which ratepayers also would pay for.

Although PSE will begin to incur amortization expense upon booking the regulatory asset, PSE will essentially recover those costs as ratepayers continue to pay current rates, which includes annual depreciation expense for Unit 4 and the return on the Unit 4 rate base.

Q. Please explain PSE's proposed accounting treatment for the O&M expense currently embedded in rates and your concern.

A. PSE currently incurs about $9.3 million annual O&M expense for Colstrip Unit 4,[22] and that amount is embedded in customer rates as a fixed production cost. After the sale of Unit 4 closes, ratepayers will continue to pay for the $9.3 million expense currently embedded in rates, even though PSE will no longer incur that $9.3 million expense. Curiously, PSE claims a $[redacted] million cost reduction in O&M expense as a benefit in its cost-benefit analysis, [23] even though ratepayers continue to pay $9.3 million of that.

The logical remedy to this problem is to book the annualized amount of $9.3 million to a regulatory liability until rates from PSE's next GRC go into effect and

[21] Free, Exh. SEF-1CT at 7:16-21.
[22] Free, Exh. SEF-05T at 15:1-3.
[23] *See* Table 1 in my testimony.

then return that amount to ratepayers. However, that is not PSE's proposal. PSE's proposal is to include the $9.3 million in its PCA Mechanism imbalance calculation as an offset to its actual power cost. PSE argues that the offset is appropriate because the Company will incur higher variable power costs due to the cost of replacement power.[24]

However, PSE's proposal has the effect of allowing PSE to share in the $9.3 million benefit that the Company includes in its portrayal of net benefits (to ratepayers) associated with the sale of Unit 4. Since annual PCA imbalances pass through the PCA's dead band and sharing bands, a $9.3 million reduction to actual power costs is not equivalent to a $9.3 million refund to customers.

Q. Please explain your concern regarding PSE's variable power cost after the sale.

A. PSE did not propose to modify the PCA variable power cost baseline in this proceeding. However, ratepayers will be on the hook if the actual variable power cost exceeds the authorized power baseline cost. If the Unit 4 sale is approved, everything else being equal, PSE would incur a higher amount of variable power cost via: (1) the new Colstrip PPAs and (2) market purchases. The replacement power cost from the two sources combined exceeds the avoided variable dispatch cost for Colstrip Unit 4.[25] The Colstrip PPAs and market purchases are estimated to cost about $[redacted] million and $[redacted] million, respectively, a total of $[redacted] million on an annual basis.[26] Because the Colstrip PPAs are structured in a way that guarantee

[24] Free, Exh. SEF-1CT at 23:6-15.
[25] *See* Table 1 in my testimony.
[26] Song, Exh. CLS-09 at 4 (tab "No Hedging"); *See also* Table 1 in my testimony.

NorthWestern Energy Corporation (NorthWestern) and Talen's recovery of Unit 4 costs and uses the Mid-C market rate as a minimum price, the actual replacement power costs can be even higher.[27] In that case, the net benefit claimed from the sale could become a net cost. As a result of the transaction, PSE ratepayers could be saddled with very high power costs through PCA rates.

Q. Do you have other concerns about other type of post-sale costs?

A. Yes. I am concerned that PSE ratepayers may have to pay for additional decommissioning and remediation (D&R) costs caused by the continued operation of Unit 4 after the sale for an uncertain duration. It does not seem fair for ratepayers to pay to remediate any incremental pollution after the sale.

IV. STAFF'S RECOMMENDED CONDITIONS

Q. Please summarize the concerns you identify above.

A. As I describe above, PSE's application fails to adequately demonstrate a quantifiable net benefit with certainty; nor does it deliver a plan to pass the net benefit to ratepayers even if there is any. My analysis shows that the Unit 4 sale, in conjunction with the Colstrip PPAs, could produce a net saving of $[redacted] million in the best-case scenario, or a net cost of $[redacted] million in the worst-case scenario over the next five years. PSE's accounting petition does not provide ratepayers the full benefit of the

[27] Roberts, Exh. RJR-9T at 37.

avoided costs, which are currently embedded in rates but PSE will not incur after the sale.

Q. How do you propose to remedy your concerns?

A. I recommend five conditions below as targeted responses to the concerns I identify above, in the event that the Commission approves the Proposed Transactions as a whole or individually:

A. Order PSE to utilize PTCs to address the unrecovered plant balance of Colstrip Unit 4 and book ratepayers' payment for the Colstrip Unit 4 depreciation expense as a regulatory liability;
B. Order PSE to book ratepayers' payment for the Colstrip Unit 4 O&M costs as a regulatory liability;
C. Cap the ratepayers' responsibility for the Colstrip PPAs;
D. Disallow any incremental decommissioning and remediation costs after the sale; and
E. Order PSE to book ratepayers' payment for the depreciation expense of and the return on transmission assets for sale as a regulatory liability.

A. PSE Shall Utilize Production Tax Credits And Record Ratepayers' Payment For Depreciation Expense In Regulatory Liability

Q. How much depreciation expense associated with Colstrip Unit 4 (return of the Colstrip Unit 4) is embedded in the rates from the 2019 PSE GRC?

A. In the 2019 PSE GRC, the Commission approved a $19.5 million annual depreciation expense for Colstrip Unit 4 in the revenue requirement, assuming a retirement date of December 31, 2025.[28] Of the $19.5 million, $16.9 million is associated with the physical life of the Unit 4 plant, $0.7 million is associated with decommissioning and $1.9 million is for remediation.[29]

Q. In this docket, what is PSE's proposal regarding the unrecovered plant balance of Colstrip Unit 4?

A. PSE proposes to move the unrecovered plant balance to a "Colstrip Unit 4 Unrecovered Plant Regulatory Asset" account and PSE will amortize this regulatory asset account through December 31, 2025.[30] Under PSE's proposal, ratepayers' contribution to the depreciation expense will be used to offset the amortization expense for the new Unit 4 regulatory asset.[31]

Q. Does Staff support PSE's proposal?

A. No. Although, in principle, Staff does not oppose the establishment of a Colstrip Unit 4 Unrecovered Plant Regulatory Asset (if the Commission authorizes the Unit 4 sale), Staff believes there is a better option than asking ratepayers to continue paying for Unit 4 through the depreciation expense embedded in current rates. With the available PTCs and an expectation that PSE utilizes those PTCs to offset

[28] Free, Exh. SEF-05T at 6:11-12 (Table 1).
[29] *Id*.
[30] Free, Exh. SEF-1CT at 7:16-24.
[31] Free, Exh. SEF-1CT at 9:1-5.

unrecovered plant for Colstrip, it seems unnecessary to ask ratepayers to continue to pay for Colstrip Unit 4.

Q. What is Staff's recommendation?

A. Staff recommends that the Commission order PSE to utilize monetized PTCs to offset the remaining net book value for Colstrip Unit 4 (life asset portion only). More specifically, Staff recommends that at the closure of the Colstrip Unit 4 sale, PSE shall hold the remaining unrecovered plant balance of Unit 4 in a regulatory asset account in rate base until the earlier of (i) the recovery of all plant balances for Colstrip Unit 4 through monetized PTC offsets or (ii) December 31, 2029. PSE shall adhere to the priority for the use of PTCs identified in the 2017 PSE GRC settlement agreement and in sequence of events as they occur.[32] PSE shall assume the risk if it is unable to monetize the PTCs sufficient to fully offset the unrecovered plant balances for Colstrip Unit 4.

Critically, with the remaining plant balance/Colstrip Unit 4 regulatory asset being addressed by monetized PTCs, there no longer would be a need for PSE to continue recovering the Colstrip Unit 4 depreciation expense embedded in current rates. As a corollary to the Commission ordering PSE to offset unrecovered Unit 4 plant balances with PTCs, the Commission should order PSE to begin recording, to a regulatory liability, ratepayers' payment for the depreciation expense for Colstrip

[32] In other words, monetized PTCs shall be used in the following sequence (i) to fund $5 million Montana Community Transition payment; (ii) to recover unrecovered plant balances for Colstrip Units 1 and 2; (iii) to recover unrecovered plant balances for Colstrip Unit 4; (iv) to recover unrecovered plant balances for Colstrip Unit 3, and (v) to fund and recover prudently incurred decommissioning and remediation costs for all units if the cost recovery built in Colstrip units depreciation rates were not sufficient. *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-170033, Order 08, 41, ¶ 112 (December 5, 2017).

Unit 4 embedded in current rates—but which PSE will no longer incur (approximately $16.9 million annually, or $1.4 million monthly). The decision for when and over what time horizon the regulatory liability should be returned to ratepayers can be considered at a later date.

Q. Why do you recommend using PTCs to offset the unrecovered plant balance?

A. Staff's recommended treatment of the Colstrip Unit 4 unrecovered plant balance is based on the Commission-approved settlement terms with regard to Colstrip in the 2017 GRC.

The 2017 GRC settlement term specified the prioritization in use of monetized PTCs as follows:

> PSE shall use the monetized PTCs in the second account in accordance with the following priority for use: (i) to fund community transition planning funds of $5 million, as identified in paragraph 118; (ii) to recover unrecovered plant balances for <u>Colstrip Units 1 through 4</u>; and (iii) to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 through 4.[33] (Emphasis added by Staff)

In that settlement, parties agreed that PSE will move the remaining unrecovered plant balance of Colstrip Units 1 and 2 to a regulatory asset upon their closure and PSE will offset the regulatory asset with PTCs as they are monetized on federal tax returns. If PSE is unable to monetize sufficient PTCs by 2029, PSE agreed to write off the remaining value of the regulatory asset. Staff's recommended

[33] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-170033, Order 08, Appendix B. Settlement Stipulation and Exhibits, ¶117 (Dec. 5, 2017).

use of PTCs follows the exact settlement agreement terms with regards to unrecovered plant balance of Colstrip units.

Q. Will there be sufficient PTCs to offset the undepreciated plant balance of Colstrip Unit 4?

A. Yes. PSE estimates that the total amount of PTC regulatory liability is $240 million.[34] As of December 31, 2019, PSE had monetized $87.2 million of PTCs.[35] Per the 2017 GRC settlement terms, PSE will use $5 million for the Montana Community Transition Fund and $[redacted] million to offset the unrecovered plant balance for Colstrip Units 1&2 upon their closure in December 2019.[36] Approximately $[redacted] million remains.[37] It is reasonable to expect that the remaining PTCs will be able to cover the unrecovered plant balance of Colstrip Unit 4.

Q. What are the advantages of Staff's recommended treatment of the unrecovered plant balance?

A. Staff's recommended treatment balances the interests of the current generation of customers with the previous generations. It allows ratepayers to stop paying for Colstrip Unit 4 assets after the Unit 4 sale and to start benefiting from the avoided depreciation expenses.

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[34] Free, Exh. SEF-1CT at 5: 6-10.
[35] *Id.*
[36] Free, Exh. SEF-1CT at 5:15 – 6:2.
[37] Free, Exh. SEF-1CT at 6:1-2.

Q. Why do you think utilizing PTCs can mitigate the intergenerational inequity issue?

A. Staff recognizes that part of the remaining Colstrip plant balance today is due to the slow depreciation in the past. It is not fair to ask the future generation of ratepayers to pay for the stranded cost of an investment that no longer benefits them and that is partially caused by the under payment of previous generations. Under Staff's proposal with PTC offsets, the future generation of ratepayers will no longer need to pay for the unrecovered plant balance. The PTCs that PSE now monetizes are attributable to renewable projects developed over the last three decades. Staff's recommendation would even out the costs and benefits between two generations of ratepayers. This intergenerational equity issue was the key consideration underlying the 2017 GRC settlement terms concerning PTCs.

Q. Is there any more clarification you would like to make?

A. Yes. Staff's recommended deferral of regulatory liability applies only to the physical life portion of the depreciation expense, and not the D&R portions. The Commission should continue to allow PSE to collect in rates to pay for the Colstrip Unit 4 D&R costs until the rates are re-set in the next GRC.

Q. What is PSE's proposal on the recovery of remediation costs?

A. PSE proposes to move the unrecovered legal remediation asset to a separate regulatory asset and amortize it through December 2025, using the revenue from existing rates to offset the unrecovered balance (approximately $1.9 million annually).[38] PSE proposes to move the legal remediation liabilities currently recorded in FERC account 230 Asset Retirement Obligations (ARO) to FERC account 228.4 Accumulated Miscellaneous Operating Provisions (Environmental Remediation) with appropriate adjustment to the valuation methods.[39]

Q. Does Staff agree with PSE's proposal on the accounting treatment of remediation costs?

A. Yes. If the Commission approves the Colstrip Unit 4 sale on the grounds that it is in the public interest, Staff supports a separate Colstrip remediation regulatory asset account to which the ratepayers will be paying the same amount of remediation costs as currently embedded in rates. It is consistent with the Commission's decision in the 2019 GRC on Units 3 and 4 D&R regulatory asset account.[40] It is also consistent with RCW 19.405.030 (1)(b).[41] The conversion of ARO to a separate environmental remediation liability account is also appropriate.

Q. What does PSE propose for the recovery of decommissioning costs?

A. PSE did not request any accounting treatment for the decommissioning portion of the cost recovery. PSE proposes that ratepayers continue to pay for the decommissioning

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[38] Free, Exh. SEF-1CT at 14–16. The remediation portion of the depreciation expense is updated in Exhibit SEF-5T at 6:11-12.
[39] *Id*.
[40] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 & UG-190530, Order 08, 123–124, ¶ 426 (Jul. 8, 2020) (2019 GRC Order).
[41] RCW 19.405.030 (1)(b) provides 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.

portion of the depreciation expense (approximately $0.7 million annually).[42] The payment would continue to accumulate decommissioning costs in FERC account 108 Accumulated Provision for Depreciation after the sale.[43]

Q. Does Staff agree with PSE's proposal on the recovery of decommissioning costs?

A. Yes. I believe it is appropriate. Staff's understanding is that ratepayers' payment towards decommissioning costs will be recorded in Account 108 under PSE's proposal. When the decommissioning of Unit 4 occurs, the payment will be netted against the actual cost. The difference between the actual decommissioning cost, once known, and the collected payment for decommissioning will be included in the Colstrip Decommissioning and Remediation Regulatory Asset account.

Q. Why does Staff not recommend utilizing PTCs to offset the D&R cost?

A. Staff proposes that PTCs should be first and foremost used to offset the unrecovered balance of the physical assets of Colstrip units. Such prioritization was prescribed in the 2017 GRC settlement stipulation. However, this recommendation does not preclude future discussions on how to best address prudently incurred D&R costs, using PTCs or other sources of funding, if the actual D&R costs exceed the current estimated level. In fact, Staff envisions that if there are monetized PTCs remaining

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[42] Free, Exh. SEF-1CT at 17: 1-12. The decommission portion of the depreciation expense is updated in Exhibit SEF-5T at 6:11-12.
[43] *Id.*

after covering the plant balances, those funds could be available to offset D&R costs for Colstrip Units 3 and 4.[44]

B. PSE Shall Record Ratepayers' Payment For O&M Expense In Regulatory Liability

Q. What is PSE's proposed accounting treatment for this cost?

A. For the purpose of calculating the monthly PCA imbalance, PSE proposes to include the amount of the Colstrip Unit 4 production O&M costs as a credit to actual costs—until the cost of the Colstrip PPAs is reflected in general rates in a future GRC.[45] This cost comes to $9.3 million per year, or $0.8 million per month.

Q. What is PSE's rationale for their proposal?

A. PSE states that its proposal is merely to recognize that the proposed transaction could increase PSE's power cost and that "[a]ligning the costs established in rates with the change in cost structure that occurs with the NorthWestern Energy PPA will allow

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[44] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 & UG-190530, McGuire, Exh. CRM-1T at 37: 3-5 (not included as an exhibit to this testimony). Mr. McGuire in this portion of his testimony stated:

> [I]f there are monetized PTCs remaining after covering unrecovered plant balances, those funds would be available to offset D&R costs for Colstrip Units 3 and 4.

[45] Free, Exh. SEF-1CT at 22:5 – 23:5.

PSE to offset costs with amounts included in rates and flow both through the PCA mechanism."[46]

Q. Do you agree with PSE's proposal?

A. No.

Q. Why do you not agree with PSE's proposal?

A. The PCA mechanism is intended to recover PSE's power costs in rates with built-in incentives. It has a $17 million dead band for either under- or over-recovery of power costs, a sharing band for cost variances between $17 million and $40 million in either direction, and another sharing band for costs beyond $40 million in either direction.[47] The PCA imbalance is calculated as the difference between the authorized variable power cost revenue (baseline PCA rates times actual load) and the actual cost. As I mentioned in Section B(ii), PSE's proposed creative accounting of reducing the actual cost by $9.3 million has the equivalent effect of increasing the PCA baseline by $9.3 million. Staff is opposed to this approach, especially when the PCA baseline was just authorized by the Commission two months ago. Given the

[46] Free, Exh. SEF-1CT at 23:11-13.
[47] In the current PCA design, the costs and benefits of power cost variances are shared between PSE and customers according to three graduated levels of power cost variance, or sharing bands. The dead band includes the first $17 million of power cost variance (+/-). Within the dead band 100% of costs and benefits are retained by PSE. The first sharing band includes power cost variances between $17 and $40 million (+/-). Within this band costs are shared 50 percent to PSE and 50 percent to customers, while benefits are shared 35 percent to PSE and 65 percent to customers. The second sharing band includes power cost variances over $40 million (+/-). Costs and benefits in this band are shared 10 percent to PSE and 90 percent to customers.

dead band and the sharing bands in the PCA, ratepayers may not be able to capture the full amount of production O&M cost savings under PSE's proposal.

Q. What is your recommendation on the O&M expense?

A. If the Commission approves the Unit 4 sale, I recommend that the Commission order PSE to begin recording to a regulatory liability ratepayers' payment for the O&M expense for Colstrip Unit 4, which is embedded in current rates, but which PSE will no longer incur after the closure of the Unit 4 sale, and pass it to ratepayers at a later date. This is the only way to ensure that ratepayers receive the full benefit from the avoided production O&M.

Q. Why should ratepayers receive the benefit from the avoided production O&M?

A. As illustrated in PSE's cost-benefit analysis, the estimated net benefit claimed by PSE depends on the avoided O&M. If the avoided O&M expense is not passed on to ratepayers, then the alleged net benefit will not accrue to them. In that case, the proposed transaction will not be in the public interest because it will end up saving PSE money–not producing savings for ratepayers. PSE should not be permitted to use this O&M revenue to offset any increased power costs before the Commission makes a prudency determination on the Colstrip PPAs.

Q. Will PSE incur higher variable power costs if the Unit 4 sale and the Colstrip PPAs are approved?

A. I do not know. Variable power costs depend on many factors such as weather, hydro generation levels, load, gas prices, and other market conditions. It appears that everything else being equal, PSE would end up paying for more variable power due to the PPAs. However, it is hard to know the actual difference. For example, if the generation from hydro and wind sources is high and the customer load is low, PSE would not need to replace the full 95 MW share of the Colstrip generation lost due to the Unit 4 sale. In that case, PSE would incur lower variable power cost, everything else equal.

Q. Should there be a revision to PSE's PCA baseline rates to reflect the potential increase in power cost if Unit 4 sale and the Colstrip PPAs are approved?

A. Maybe. Staff recognizes that a number of factors may have changed from the power cost modelled in the 2019 GRC. If there is a need, PSE may initiate a GRC or Power Cost Only Rate Case (PCORC) to update the PCA baseline to more closely align with its projected power costs. Staff is not opposed to a GRC or PCORC. However, Staff is against any proposal to adjust the PCA baseline in a piecemeal fashion due to a change in one single variable, such as the addition of the Colstrip PPAs in this case. The PCA baseline needs to be reviewed holistically.

C. The Commission Should Cap The Colstrip PPAs

Q. Please summarize Staff's concerns about the Colstrip PPAs.

A. I believe the Colstrip PPAs are structured in a way intended to protect NorthWestern and Talen while exposing PSE ratepayers to great risks. The Commission should impose a condition to protect PSE ratepayers from price spikes under the Colstrip PPAs.

Q. Please explain your concern.

A. Pursuant to the Colstrip PPAs, the contract price consists of two portions:

(1) the fixed portion: annual O&M costs (Base);[48] and

(2) the variable portion: the higher of (i) the Mid C Day-Ahead Index Price for on-peak and off-peak periods, as applicable, minus O&M Costs (Base) Equivalent;[49] and (ii) the Floor Price[50] applicable to such hour.[51]

In other words, PSE will be responsible for covering (1) a pro rata share of the ongoing O&M cost for Unit 4 and (2) a variable cost that starts with a Floor Price. This is not a fair deal for ratepayers. The future Colstrip Unit 4 owners would be able to decide the Base O&M amount. PSE and its ratepayers would be passive

[48] "O&M Costs (Base)" means, the 90 MW share of the O&M Cost (Base) fixed costs as identified and approved annually for Colstrip Units 3 and 4 Budget.
[49] "O&M Costs (Base) Equivalent" means, O&M Cost (Base) divided by the annual net generation, as identified and approved annually for Colstrip Units 3 and 4 Budget.
[50] "Floor Price" means, for any hour during the Period of Delivery, a per MWh price calculated in accordance with Exhibit A of the PPA – Methodology for calculating the minimum electric cost. The minimum charge for electricity is the combination of fuel and non-fuel variable costs.
[51] Robert, Exh. RJR-6 at 51–52.

cost takers. Both the Base O&M portion and the variable portion of the pricing structure pose risks to PSE ratepayers.

Q. Why does the <u>Base</u> O&M portion of the PPAs pose risks to PSE ratepayers?

A. PSE's cost-benefit analysis assumes a $[redacted] million annual Base O&M payment based on Talen's budget.[52] However, it is plausible that Talen and NorthWestern would incur a higher O&M expense, knowing a portion of it would be picked up by PSE ratepayers through the PPAs.

Q. Why does the <u>variable</u> cost portion of the PPAs pose a risk to PSE ratepayers?

A. The variable cost portion of the PPAs depends on an hour-by-hour comparison of (1) the Mid-C Day-Ahead price minus Colstrip Unit 4's Base O&M rate and (2) NorthWestern/Talen's actual dispatch cost, also called "Floor Price." Based on Exhibit A to the Colstrip Unit 4 Contingent Confirmation, the Floor Price consists of two parts: [redacted].[53] The curren Floor Price used in PSE's PPA cost calculation is estimated at $[redacted]/MWh, far higher than the hourly market prices from PSE's power cost model minus the Base O&M rate, which averaged at $[redacted]/MWh, for the majority of the hours. PSE's analysis showed that for the PPA duration, the Floor Price is so high that PSE would

[52] In Staff's alternative cost-benefit analysis in JL-4C and JL-5C, I assume a very moderate annual Base O&M payment based on the historical average. If the Base O&M is increased, the net benefit of the Unit 4 sale will further reduce.
[53] Roberts, Exh. RJR-08C at 5.

pay the Floor Price in [redacted] percent of the more than 43,000 hours.[54] In other words, the cost of the PPAs will be predominantly set at NorthWestern and Talen's Floor Price.

Q. What is Staff's evaluation of the cost of the Colstrip PPAs?

A. The Colstrip PPAs clearly guarantee NorthWestern and Talen's cost recovery through the Floor Price when the operational cost is high. The PPAs also deliver NorthWestern and Talen profit if the market price exceeds their cost. Under normal market conditions, the Colstrip PPA costs will be primarily determined by the future Unit 4 owners' cost—over which PSE would have little control. Under extreme market conditions where the Mid-C price is higher than the Unit 4 Floor Price, PSE would end up paying a high PPA price that is benchmarked by the high market price. PSE ratepayers will be at risk in either scenario.

Q. What is Staff's recommendation?

A. Staff believes there needs to be thresholds to protect ratepayers' interest. Staff recommends that ratepayers' responsibilities for the combined PPAs be limited to $[redacted] million on an annual basis for the duration of the PPAs. The proposed cap is based on the PPAs cost estimate with Staff's alternative cost assumptions under normal market conditions.[55] PSE may reflect no more than the cap for the purpose of the PCA imbalance calculation, or for the purpose of the revenue requirement

[54] The percentage is calculated based on PSE Witness Song's workpaper supporting Exh. CLS-09C. The workpaper itself contains a large spreadsheet that is too voluminous to present as an exhibit. Staff will provide Staff's analysis in an electronic workpaper available upon request.
[55] Liu, Exh. JL-4C at 5.

calculation in future GRCs or PCORCs. PSE shareholders shall absorb any payment above the cap.

Q. How does this recommendation protect the public interest?

A. The proposed caps are not intended to penalize PSE, but rather to limit ratepayers' exposure to extreme price fluctuations. If the PPAs are priced at an unreasonable level, the claimed net benefits will diminish, and the Proposed Transactions may no longer generate net benefit and therefore may not be in the public interest. This condition should not be construed as a pre-approval before the Commission determines the prudency of the Colstrip PPAs in a future proceeding.

D. PSE Shall Record Ratepayers' Payment For Depreciation Expense And Return Associated With The Transmission Asset For Sale In Regulatory Liability

Q. How much cost is embedded in rates regarding the transmission asset for sale?

A. PSE estimates that the net book value of the 95 MW transmission asset for sale is about $1.6 million as of December 31, 2020.[56] There is about $0.1 million annual depreciation expense and $0.1 million annual return associated with the segments of the Colstrip transmission assets proposed for sale.

[56] Liu, Exh. JL-6 at 5.

Q. What is PSE's proposed accounting treatment for the Colstrip transmission assets for sale?

A. PSE proposes that no deferral is necessary because: (i) the overall balance in the transmission accounts continues to increase, representing amounts not in rates; and (ii) the difference between the net book value at the time of sale and the revenue requirement associated with these specific assets is minimal.[57]

Q. What is Staff's opinion about PSE's proposal?

A. Staff agrees that the total $0.2 million revenue requirement is rather immaterial. However, PSE shall not continue to recover in rates the return of and the return on the Colstrip transmission asset after it no longer owns and uses it. If the Commission approves the transmission sale, Staff recommends that the Commission order PSE to book ratepayers' payment for the depreciation expense and the return associated with the transmission as a regulatory liability after the closure of the sale and pass it on to ratepayers at a later date. The same condition should apply to PSE's potential sale of more Colstrip transmission assets in 2025.

[57] Free, Exh. SEF-1CT at 21:14-17.

E. The Commission Should Disallow Any Incremental Decommissioning And Remediation Costs In Rates

Q. What problem do you perceive concerning the future Unit 4 decommissioning and remediation costs?

A. The Unit 4 Purchase and Sale Agreement states that "PSE would bear its pro rata share of remediation costs, decommissioning costs, and miscellaneous shutdown costs."[58] It means that PSE would be responsible for 25 percent of the Unit 4 D&C costs—regardless of how the unit runs and how long the unit runs, unless such costs are caused by violations of environmental laws or releases of hazardous substances that wholly or predominantly take place after the closing of the sale.[59] Staff is very concerned about any incremental D&R costs attributable to the prolonged operation of Unit 4 under the new ownership.

Q. What does the Unit 4 Purchase and Sale Agreement say about the incremental environmental liabilities?

A. The Purchase and Sale Agreement specifies that PSE will be responsible for losses (including environmental remediation liabilities) arising from the ownership or operation of the Colstrip 4 Interests, Colstrip Units 3 & 4, or the common facilities that are wholly or partially caused by or arise from events or occurrences which took place before the closing date based on its pre-closing date project shares.[60]

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[58] Roberts, Exh. RJR-1CT at 10.
[59] Roberts, Exh. RJR-6 at 31.
[60] Roberts, Exh. RJR-1CT at 26:7-14.

NorthWestern and Talen will be responsible for such losses which took place on and after closing.[61] However, the incremental environmental liabilities attributable to the new owners' continued coal combustion after the sale do not count as "incremental losses" under this provision.[62] They still fall into PSE's pro rata responsibilities.

Q. Do we have an estimate for the incremental D&C costs which may be caused by the continued operation of Unit 4 after the sale?

A. No. As Staff Witness Gomez stated in his testimony, the final D&R costs as well as the cost for the dry ash disposal system are unknown at this point.[63] The incremental D&R costs after the sale would be even harder to discern. Any change in laws, regulations, and technologies could also affect the D&R measures and costs in the future.

Q. What does PSE say about the cost of the dry ash disposal system?

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[61] *Id.*

[62] *See* Roberts, Exh. RJR-6 at 31–32. Section 8.2 of the Purchase and Sale Agreement provides

> The parties specifically recognize that the Project will continue to burn coal and generate coal combustion residuals after Closing, and agree, notwithstanding anything to the contrary in the proviso contained in the prior sentence, that Losses arising from the continued burning of coal and the generation, storage, deposit, and Release of coal combustion residuals, including the deposit of coal combustion residuals into ponds, the dry storage or staging of coal combustion residuals, and any Release of coal combustion residuals or Hazardous Substances resulting from coal combustion residuals from existing ponds, shall not be considered incremental Losses of the sort described in the preceding sentence and shall not decrease Seller's liability or responsibility for such Losses based on the Parties' respective pre-Closing Date Project Shares, such that all Losses caused by or arising from the AOC and/or CCR Rules that arise from or are caused by the deposit, storage, generation, staging, or Release of coal combustion residuals shall be based on pre-Closing Date Project Shares without regard to whether such deposit, storage, generation, staging, or Release occurs before or after Closing. (emphasis added by Staff)

[63] Gomez, Exh. DCG-1T at 42: 15-20.

A. PSE states that once the Colstrip owners switch to a dry ash disposal system in 2022, the dry ash disposal will be an O&M expense, not a remediation cost.[64]

Q. Do you feel comfortable with PSE's understanding of the cost classification for the dry ash disposal system?

A. No. We do not know how NorthWestern and Talen would classify the cost for the dry ash disposal system. Staff believes that some of the costs may be considered capital expenditures, some O&M, and possibly some environmental remediation costs. There is no clarity at this point. The dry ash disposal system, once constructed, may also increase the future decommissioning costs that PSE will be liable for.

Q. What is your recommendation to address your concern about the incremental D&R costs?

A. PSE's ratepayers shall not be responsible for any incremental D&R costs caused by continued operation of Unit 4 if the sale is approved. Staff recommends that the Commission should disallow PSE's recovery in rates of any incremental D&R costs directly attributable to the continued operation of Unit 4, after the Unit 4 sale is closed. The incremental D&R costs should include any material increase in costs related to the remediation of the existing ash ponds, ground water, as well as any remediation cost related to the future dry ash disposal system or similar systems. Any future request to recover Colstrip D&R costs brought forth by PSE needs to be screened for this purpose.

[64] Liu, Exh. JL-7 at 1.

Q. Do you have any clarification to your recommendation?

A. Yes. PSE states that the dry ash disposal cost is an intrinsic operational cost of electricity production from coal.[65] Staff agrees that, to the extent some dry ash disposal cost is properly classified as O&M costs, and, therefore could be included in the Base O&M under the PPAs.

Q. Does this conclude your testimony?

A. Yes.

[65] Liu, Exh. JL-7 at 1.